June 26, 2020

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

RE: Arizona Public Service Company's 2020 Integrated Resource Plan[1]
Resource Planning and Procurement in 2019, 2020 and 2021 Matter
Docket No. E-00000V-19-0034.

In January 2020, Arizona Public Service Company announced an ambitious goal to deliver 100% clean, carbon-free and affordable electricity to our customers by 2050. We set this goal to ensure Arizona remains a healthy and beautiful place to live and work. Today, we are filing our 2020 Integrated Resource Plan (IRP), which provides the direction and approach we plan to undertake to reach our clean energy goals.

While we are excited about fully powering our customers' future needs with clean energy, achieving a carbon-free resource mix by 2050 will be challenging. Setting nearer-term targets was important to ensuring we make meaningful progress, and to that end, our clean energy commitment consists of three parts:

- The ultimate 2050 goal to provide 100% clean, carbon–free electricity,
- A 2030 interim target of achieving a resource mix that is 65% clean energy, with 45% of our customers' electricity needs served by renewable energy[2] and
- A commitment to end our use of coal-fired generation by 2031.

With this IRP, we believe we have developed a comprehensive yet flexible plan to achieve substantial carbon reductions through necessary investments in clean energy resources, while keeping our system reliable and rates affordable for customers. The IRP includes an Action Plan that lays out the near-term actions we must take to progress rapidly to our 2030 interim target and ultimate 2050 goal. The resource portfolios included in this IRP build on the carbon-free foundation that anchors our energy mix: maintaining Palo Verde Generating Station's vital role in supplying clean energy to four states in the Southwest; increasing a diverse renewable energy portfolio that will expand significantly over the next decade; and integrating

[1] Filed in compliance with A.A.C. R14-2-703(C), (D), (E), (F), (H) and (I). The confidential version of the IRP will be provided to Staff pursuant to an executed Protective Agreement in this matter.
[2] "Clean" is measured as percent of energy mix which includes carbon-free resources like nuclear and demand-side management, and "renewable" is expressed as a percent of retail sales.

innovative solar, wind, energy storage, energy efficiency and demand-side management programs for customers that contribute to a cleaner grid.

As we move toward our renewable and carbon-free goals, we will need to solidify plans to move away from coal-fired generation. We understand that closing our coal-fired power plants will significantly impact employees as well as the surrounding communities. We will continue to engage in meaningful dialogue with these stakeholders in order to explore, better understand and prepare to address a range of potential effects, including environmental, social and economic impacts. Because we are in the process of determining the appropriate venue to examine these issues, they do not appear in this IRP, but we are fully committed to—and indeed have begun—engaging with affected stakeholders in advance of plant closures.

We are embarking on our first steps toward achieving our clean energy commitment, and we want to thank the Commission, stakeholders, communities and our customers for their time and feedback in the development of this plan. We look forward to continuing this collaboration and partnership as we address both opportunities and challenges in pursuit of our vision for a 100% clean energy future.

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2020 INTEGRATED RESOURCE PLAN

JUNE 2020 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

aps

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as “forecast,” “estimate,” “projection,” “may,” “believe,” “expect,” “plan,” “require,” “intend,” “assume,” “anticipate,” and other similar words. Because actual results may differ materially from expectations, APS cautions against placing undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by APS. A discussion of some of these risks and uncertainties is contained in APS’s Annual Report on Form 10-K and in its Quarterly Report on Form 10-Q for the quarter ended March 31, 2020 both of which are filed with the Securities and Exchange Commission. The reports are available on APS’s corporate parent’s website at www.pinnaclewest.com, and should be carefully reviewed before placing any reliance on APS’s forward-looking statements, financial statements or disclosures. APS assumes no obligation to update any forward-looking statements, even if internal estimates change, except as may be required by applicable law.

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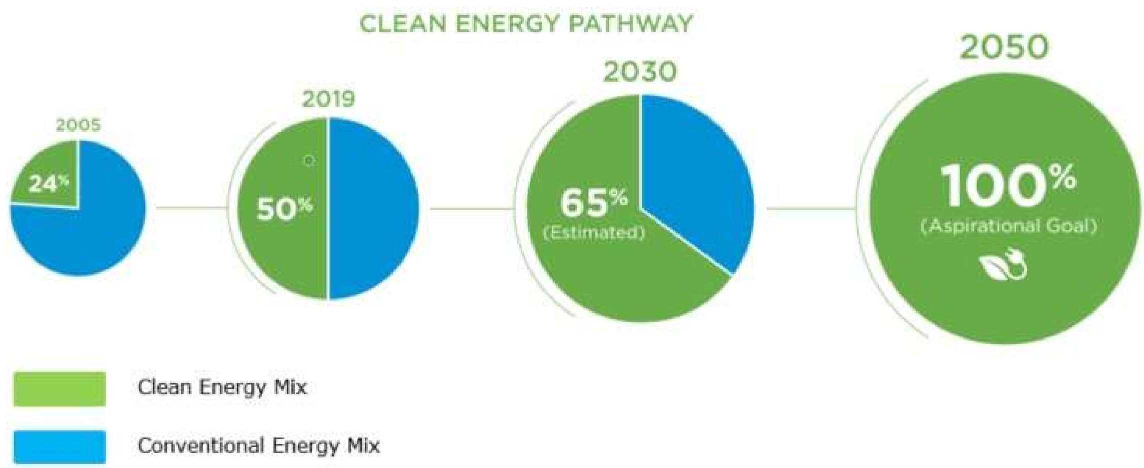
EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

In January 2020, Arizona Public Service (APS or Company) announced an ambitious goal to deliver 100% clean, carbon-free and affordable electricity to our customers by 2050. Demonstrating how the Company will approach clean energy and take a leadership role in moving toward a carbon-free Arizona, we released our clean energy commitment on June 12, 2020.[1] The APS clean energy commitment begins a new era for APS, building on our history of promoting and integrating renewable energy resources, energy efficiency, energy storage and carbon-free generation to benefit our customers and Arizona.



The 2020 Integrated Resource Plan (IRP) informs the Arizona Corporation Commission (ACC), stakeholders and customers about the direction and approach we are undertaking to reach our clean energy goal. Within the IRP, the Action Plan lays out the near-term actions we must take to rapidly progress to our 2030 interim and ultimate 2050 goals. This bold commitment will require collaboration with the Commission, stakeholders, communities and customers, and a policy environment that supports flexibility in creating a clean energy mix.

The path to 100% clean energy by 2050 is expected to be challenging, and we must make significant progress quickly to achieve the goal. To that end, we have developed a strategy to advance rapidly on our clean energy goals, achieve substantial carbon reductions and make necessary investments in clean energy resources while keeping our system reliable and rates affordable for our customers.

Our clean energy commitment consists of three parts:

- **A 2050 goal to provide 100% clean, carbon–free electricity**
- **A 2030 interim target of achieving a resource mix that is 65% clean energy, with 45% of our customers' electricity needs served by renewable energy**[2]
- **A commitment to end our use of coal-fired generation by 2031**

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[1] "We're All in for Arizona: Our Clean Energy Commitment " https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Energy-Resources/CleanEnergyReport.ashx?la=en

[2] "Clean" is measured as percent of energy mix which includes DSM, and "renewable" is measured in accordance with the ACC's Renewable Energy Standard as a percent of retail sales.

Immediate actions for the 2020-2024 Action Plan window include rapid additions of renewable energy (RE), demand response (DR), energy efficiency (EE) and energy storage systems (ESS) to make progress on our clean energy commitment. Table ES-1 summarizes a consistent strategy of resource additions that sets us on a path to meet our 2030 commitment as well as our long-term goal of providing 100% clean, carbon-free electricity. We expect the renewable energy additions will include wind and solar generation, with the exact mix determined through all-source RFP procurement processes. Our Action Plan may include short-term wholesale market purchases to maintain reliability as well. Our expectation is that existing resources in the region can act as a short-term bridge as we transition to higher levels of renewables, energy storage, demand response and demand side management (DSM).

TABLE ES-1. ACTION PLAN RESOURCE ADDITIONS (2020-2024)

2020-2024 ADDITIONS	ALL PATHS (MW)
Demand Side Management	575
Demand Response	193
Distributed Energy	408
Renewable Energy	962
Energy Storage	750
Merchant PPA / Hydrogen-ready CTs	0
Microgrid	6
Total	2,894

Our customers and stakeholders want clean energy, and we are committed to providing it. Our clean energy plan is guided by sound science and focused on achieving environmental gains – all while maintaining affordable, reliable service for our customers.

Our transition to carbon-free energy is approached in this plan over three distinct periods: The Action Plan period (2020-2024) when actions are clear; the remainder of the planning period (2025-2035) during which we have committed to add renewables and remove coal from our fleet; and the period beyond 2035 in our transition to 100% clean, carbon-free energy, a period which has less certainty around resource decisions.

Our plan for a carbon-free future will require existing resources like the Palo Verde Generating Station, the nation's largest carbon-free energy resource and a major source of Arizona's existing clean, carbon-free energy, to be foundational to our commitment. But we also need innovations and new ways of thinking about how we approach clean energy to reach our long-term goal of a fully clean, carbon-free energy mix by 2050. Some of the technologies we will depend on eventually to meet this goal are in their nascency, such as battery energy storage and the use of carbon-free hydrogen as storage medium and an energy carrier, and some are yet to be developed. We anticipate significant advancements in carbon–free electricity generation, delivery and storage, driven in part by our commitment.

We have an extraordinary opportunity to transform our supply portfolio with clean and renewable additions, both to meet our 2030 renewable energy commitment and also chart a path to zero carbon emissions by 2050. Over the next decade, approximately 1,400 MW of APS coal capacity is scheduled for retirement, and another 1,600 MW of medium-term purchases from existing merchant gas plants are scheduled to expire. These resource retirements and contract roll-offs, coupled with the need for additional capacity to serve growth in peak demand, result in new capacity needs of approximately 6,000 MW to reliably serve peak summertime customer demand. Our Action Plan update, which details our plans for the 2020-2024 period, and our IRP portfolios for the period 2025-2035 set out APS's plans to aggressively realize this opportunity for fleet transformation, resulting in a portfolio in 2031 and beyond with no coal and substantial increases in renewable generation, while meeting our reliability obligations and customers' expectations for affordability. As indicated in Table ES-1, our Action Plan relies heavily on renewables, energy storage and demand side management, including demand response and energy efficiency additions.

PLANNING PRINCIPLES

Clean

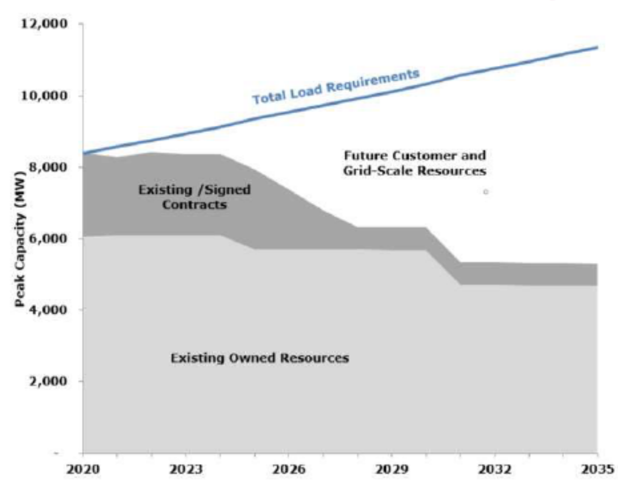
We will strive to rapidly increase the amount of clean energy on our system. Renewable energy is integral to our commitment and will require substantial ongoing investment. We currently rank fifth among all U.S. investor-owned utilities for overall solar capacity. We're also a recognized industry leader in researching and deploying technologies to deliver the sun's energy to our customers later in the day when they need power most. Our plan includes utility-scale solar and maintains rooftop solar as an important option for customers. In addition to depending on solar energy, we will further diversify our energy mix by investing in wind, energy storage, demand response and demand side management resources, including energy efficiency – all of which contribute to a cleaner grid.

Palo Verde and its carbon-free generation are critical to meeting our clean energy goals affordably. As the heart of our generation fleet, Palo Verde provides the foundation for the reliable and affordable service counted on by customers in four Southwestern states. The plant's continued operation is vital to a clean, reliable, affordable energy future for Arizona, and it is a significant contributor to the local economy. Nuclear power provides certain climate and grid resiliency advantages over other energy sources and continuously produces a predictable, steady amount of carbon-free energy.

Reliable

Providing electricity consistently to our customers, no matter the season or weather condition, is essential to the Arizona economy and the state's health and welfare. We continuously balance resource needs and trade-offs associated with affordability and reliability. Our customers' needs are evolving, and as their preferences and needs change, we will adapt to meet them. In the near term, we will utilize all resources to meet peak demand, including renewables, demand response, peak-focused energy efficiency, short-term market purchases, microgrids and of course our existing fleet. Our existing fleet is described more fully in Chapter 2 and is made up of a diverse set of resources. Those resources include renewables, energy efficiency, nuclear, natural gas and coal. And as we transition to 100% carbon-free energy, we will need to both utilize our existing resource for reliability and affordability, and at the same time scale back usage, retire and potentially transform those resources to make them part of our future carbon-free fleet. We are focused on resource decisions that keep us on the path to a cleaner, carbon-free grid.

FIGURE ES-1. APS SUPPLY-DEMAND GAP (IN MW)



Energy storage is an essential piece of our future resource mix and provides the capacity necessary to keep the system reliable. As energy storage technologies continue to develop and evolve, opportunities are created to meet our customers' needs with clean energy. Our investments in energy storage will enable intermittent renewable energy to be stored when it is produced and used later to meet customers' peak energy needs. Storage technologies will also help us use regional excess solar generation that is frequently available at low, zero and even negative prices.

Affordable

The cost of renewable energy has been steadily falling, providing access to carbon-free energy that is more affordable than ever. However, at the same time, renewable energy production levels have, in recent years, reached a point where production sometimes outstrips demand. In these instances, typically months with mild weather, we have witnessed power prices plummet, even becoming negatively priced where APS is often paid to take neighboring states power. We are limited in how much of this power we can take as our demand is near or at its lowest when negative pricing occurs. This creates opportunities for us to bring affordability to our customers.

Energy Imbalance Market
Over **150 million in savings**

Recognizing low-priced, clean energy is available, we have approached our future resources from both flexibility and reliability perspectives. We have opportunities to absorb clean, renewable energy at low or negative prices by turning off current flexible resources and through our pursuit of energy storage. We also can move the sun's energy in the summertime from daytime to later in the day and evening when customers need it most. Additionally, we are developing programs that incent our customers to shift this energy usage to the times when excess energy production is available and reduce consumption when energy is higher priced. This coordination among resource additions, market participation and customer education will allow us to rapidly change our current resource base.

Our ability to use excess clean energy from nearby states already provides significant savings to our customers. We began participating in the Western Energy Imbalance Market (EIM) in 2016, which has increased our ability to import low or negatively priced energy. As a result, EIM's gross benefits to our customers have totaled $151 million through March 2020, and we expect savings from our voluntary participation to continue. The EIM (and potentially other markets like it) will be an effective tool for integrating the region's growing clean energy resources while creating savings for customers.

Customer Focused

Technologies such as rooftop solar, LED lighting and on–site energy management devices have given residential and commercial customers more power to control their energy usage and potentially reduce their costs, while at the same time helping APS manage its system peaks. New APS programs are incentivizing customers to incorporate advanced technologies in their homes and businesses to help maximize the value of abundant solar energy. In addition, we are encouraging the widespread adoption of modern energy efficiency technologies, including smart thermostats, electric vehicle (EV) charging infrastructure, energy storage and more.

We also are extending our communication and partnerships with residential and business customers. This includes supporting their sustainability goals and providing expert advice on ways to reduce their carbon footprints affordably. We will help customers understand the advantages of consuming clean energy when it is readily available and more affordable, and use energy-saving technologies to reduce their electricity use and lower their monthly bills. Many of our industrial and commercial customers are responding to direction from their customers, investors and boards to improve their sustainability profiles. We can draw upon our own experience and our industry's research to assist these businesses in reducing carbon emissions and meeting their clean energy goals.

Partnering with customers
and stakeholders to reach
their climate goals

PORTFOLIO DEVELOPMENT

The APS clean energy commitment serves as the foundation of the 2020 IRP. We have an immediate opportunity to add clean resources while maintaining reliability. With nearly 3,000 MW of resource retirements, contract roll-offs and load growth ahead, we are projecting a need for approximately 6,000 MW of new, reliable replacement capacity.

While our clean energy commitment serves as the IRP's foundation, we could not have come this far without the collaboration of our stakeholders. Forging a new path at APS, we convened a group of stakeholders representing different corners of the utility landscape with the common goal of bringing clean, affordable energy to our customers. Beginning in 2018, we worked alongside these stakeholders to test a variety of portfolios and scenarios to build a collective path forward.

While the working group did not always fully agree on the best resource portfolio, we recognized that we could offer a menu of portfolios that still achieve our clean energy vision. The portfolios discussed here offer just that – a comparison of paths that all ultimately lead APS to delivering 100% clean, carbon-free and affordable electricity to our customers by 2050.

The immediate path ahead is clear: aggressively deploy renewable resources plus storage to replace coal capacity and meet load growth, supplement this clean capacity with additional renewable energy and continue to monitor and adopt advanced technologies, particularly long-duration storage, to reduce the role of natural gas in the portfolio as quickly as possible, consistent with affordability and reliability.

PORTFOLIO DESCRIPTIONS AND HIGHLIGHTS

APS developed three portfolios for the 2020 IRP that meet both our reliability and clean energy needs over the Planning Period:

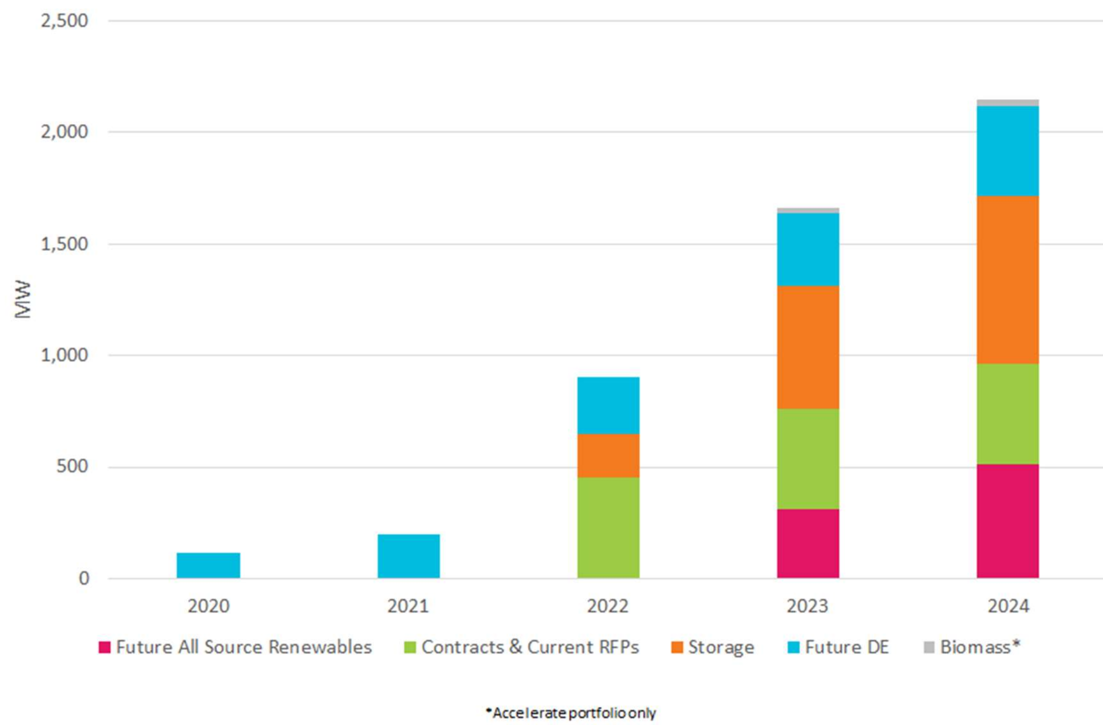
Path 1 – Bridge: Strong and focused, the Bridge portfolio provides APS with all the tools we have today and the ability to adopt all the tools of tomorrow. This portfolio starts with significant renewables plus storage. This portfolio also enables the opportunity to build hydrogen-ready, gas-fired generation and use the region's current fleet of merchant gas generators. The Bridge portfolio recognizes the importance of natural gas as a bridge fuel, allowing us to provide reliability and affordability while transitioning the portfolio to 100% clean. It also allows time for new technologies to mature and become affordable, allowing for a more diverse future portfolio.

Path 2 – Shift: Calculated and committed, the portfolio starts with additional renewables plus storage on top of that contained in the Bridge case. The Shift portfolio also moves APS away from natural gas more quickly by excluding any new natural gas generation. Purchase of regional merchant gas generation under PPAs will still be important to balance the trade-offs of affordability and reliability and allow future resource options time to develop. By maintaining current capacity levels, we can engage emerging technologies and integrate them onto our system through a paced approach.

Path 3 – Accelerate: Fast and ambitious, this portfolio will require an enormous procurement of renewable energy and energy storage to replace system capacity and maintain reliability. It does not allow for any new natural gas generation to be procured, either through new-build or PPAs, but allows for a more rapid approach to our clean energy goals. The reduction in resource options leads to a significantly larger amount of new resource additions to the portfolio to maintain reliability. This path would require the most vigilance in maintaining affordability for customers to ensure the pace and scale of investments remain aligned with the rate-setting processes.

When building the portfolios that reach our 2035 goals, we recognized that all three plans call for the same resources within the near-term Action Plan window. This struck us as significant because it indicates certainty in what our next steps must be to stay on course toward the goals in our clean energy commitment. As we set out to issue the RFPs to procure the next set of resources through 2024, we also know that technology and policy will change. As new technologies emerge and costs decline, we are committed to updating the assumptions of each portfolio above with a commitment to our customers to keep rates affordable, keep their lights on and to deliver increasingly cleaner energy until no carbon is left in our system.

FIGURE ES-2. RENEWABLE AND RESOURCE ADDITIONS



In developing the Action Plan additions for each portfolio, we recognize the need to make rapid progress by adding renewables and clean energy to achieve our goals while maintaining system reliability. The addition of renewables and energy storage to our system is projected to meet those requirements while maintaining affordability for our customers and moving toward a lower-carbon future. All three plans employ almost identical near-term additions during the Action Plan window and are summarized in Figure ES-2[3].

As shown in Figure ES-2, the pace of resource additions is significant and necessary to meet our interim 45% renewable and 65% clean goals by 2030. This will require APS to issue several all-source RFPs, the first to be announced later in 2020, that will provide the clean energy and capacity our system requires. The pace of resource additions will ultimately be dictated by our resource needs and future RFPs as we determine which resource technologies and costs provide the most affordable solution for our customers, while maintaining reliability and capacity obligations. The scale of additions within the Action Plan shown in Table ES-1 could vary somewhat based on resources selected through the all-source RFP process; however, our clean and renewable energy targets will guide us in our resource selections.

[3] Per footnote 1, only the Accelerate portfolio includes biomass (see Chapter 7 for more details). All portfolios include a 6 MW microgrid

Remainder of Planning Period (2025-2035)

Over the remainder of the planning period, 2025 and beyond, we will meet our renewable energy targets and remove all coal from the generation portfolio. The three portfolios developed for this IRP vary in their pace of renewable and energy storage resource additions as described below. Due to the diminishing ability of renewables and energy storage to meet our capacity and reliability requirements, the Shift and Accelerate portfolios require nearly 2,500 MW and 7,500 MW more nameplate capacity than the Bridge portfolio, respectively, to reliably meet our peak load conditions. All portfolios provide carbon reductions in line with levels required to achieve our carbon-free target by 2050. Table ES-2 shows the 2025-2035 additions used to evaluate the remainder of the planning period.

TABLE ES-2. RESOURCE ADDITIONS: FUTURE RESOURCES (2025-2035)

2025-2035 ADDITIONS (MW)	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO
Demand Side Management	1,027	1,027	1,027
Demand Response	500	550	600
Distributed Energy	1,177	1,177	1,177
Renewable Energy	5,488	6,988	9,388
Energy Storage	4,100	5,750	9,800
Merchant PPA / Hydrogen-ready CTs	1,859	1,135	0
Microgrid	125	125	0
Total	14,276	16,752	21,992

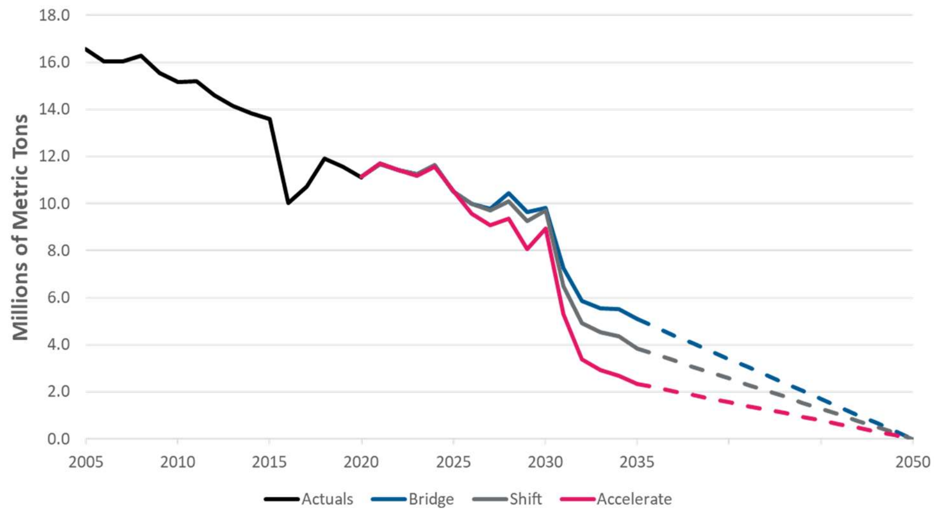
Finally, Table ES-3 presents the APS generation portfolio additions in their entirety by path through 2035, which includes all projected additions to the APS system over the entire IRP evaluation period. Note that these totals will be evaluated and updated through future Action Plan updates and IRPs. A trend that became apparent in our portfolio development was that an increasing quantity of renewable energy and energy storage would be necessary to displace each megawatt of natural gas. This is due, in a large part, to the limits of energy storage technology and costs today. While energy storage has become a competitive peaking resource, the current technology available is not as effective at managing longer durations. The industry recognizes this challenge, and longer-duration energy storage is currently being developed. As such, the future of storage technology will be critically important to our success as we reach our clean energy goals.

TABLE ES-3. RESOURCE ADDITIONS: FUTURE RESOURCES (2020-2035)

2025-2035 ADDITIONS (MW)	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO
Demand Side Management	1,602	1,602	1,602
Demand Response	693	743	793
Distributed Energy	1,585	1,585	1,585
Renewable Energy	6,450	7,950	10,375
Energy Storage	4,850	6,500	10,550
Merchant PPA / Hydrogen-ready CTs	1,859	1,135	0
Microgrid	131	131	6
Total	17,170	19,646	24,911

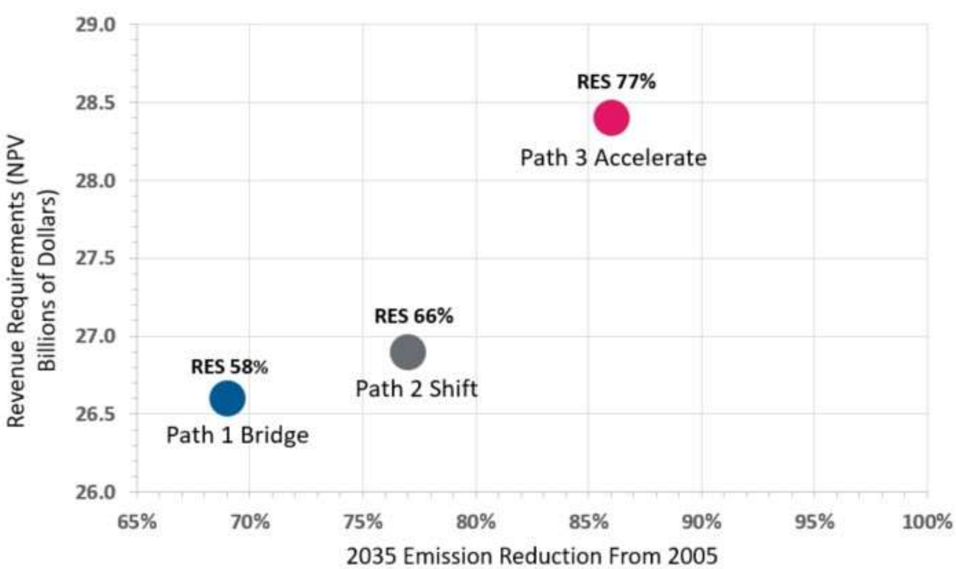
In addition to the resource differences in Table ES-3, our 2030 clean and renewable interim targets guide us to our long-term goal of 100% clean and zero carbon emissions. Depending on which path we follow, Figure ES-3 shows how our carbon trajectory may look over the next 30 years, with all paths leading to 100% clean, carbon-free electricity by 2050.

FIGURE ES-3. CARBON REDUCTION TRAJECTORY



There are many trade-offs and considerations in the analysis of portfolios, and one of the most important trade-offs is between the cost of the portfolios and the amount of carbon reduction achieved. That trade-off is summarized in Figure ES-4, which demonstrates that costs increase with a move from the Bridge to Shift portfolio and increases more rapidly when moving from the Shift to Accelerate portfolio. Energy storage and renewables begin to show diminishing returns to carbon reductions when we exceed a 60%-70% RES. The results suggest that as we approach high levels of renewable energy and energy storage on our system, advances in long-duration energy storage technology and cost reductions will become increasingly critical to helping us meet our clean energy and affordability goals. As more information becomes available and the Planning Period turns into the Action Plan window, we expect to update these trade-offs.

FIGURE ES-4. PORTFOLIO COST AND CO2 EMISSION REDUCTION



PORTFOLIO COMPARISONS

We have not selected a single portfolio, but rather focus on several paths that could enable us to achieve our clean energy goals while maintaining flexibility in how we get there. Importantly, these portfolios all require similar commitments through the immediate (2020-2024) Action Plan window to move us toward our future goals. The portfolios presented are not intended to be prescriptive; rather, they demonstrate we can take our first steps in the Action Plan while maintaining flexibility in how we select clean energy resources in order to preserve affordability and reliability for our customers.

Our plan overall is premised on the ability to safely and economically deploy large amounts of energy storage so that we can provide as much of the needed capacity as possible through a combination of renewable resources and storage. Though deployment of storage at this scale – at least 2,500 MW of storage capacity in the next decade – has not yet been demonstrated, we believe it is likely feasible and reasonable to reflect in our plans. In the Action Plan window through 2024, we plan to add 750 MW of storage capacity in order to meet our customers' peak demands.

As we approach 2030, we plan to deploy at least an additional 1,750 MW of storage resources to meet peak summer demand. These assets will provide the backbone of replacement capacity and energy as we look to exit coal completely by 2031.

During this time frame, we also will aggressively employ DSM programs tailored to high-value opportunities, such as shifting customers' power consumption into the midday peak solar hours and reducing use during the peak demand hours on our system to save customers money and reduce our need for additional system peak demand resources.

Renewables, energy storage and DSM are at the core of our plans to move toward a clean energy future. However, we don't know with certainty what the cost, safety and performance of energy storage technologies are going to be as we move forward. We have made assumptions in this IRP that may either prove to be too ambitious or not nearly ambitious enough. Therefore, we have developed the following portfolios as alternative paths that will evolve over time as we learn more about these technologies. It is in this light that we have provided three plans to illustrate the paths that APS may need to take to get to a clean energy future based on those uncertainties. Again, it is important to note that these three portfolios all share the same actions during the 2020-2024 Action Plan window. Table ES-4 contains a summary of the portfolios analyzed for this plan.

TABLE ES-4. 2035 CAPACITY AND ENERGY MIX BY PORTFOLIO

	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO
Description	Retire coal by 2031; demand reducing DSM; RE and ESS to meet CEC; gas bridge - extend gas-tolling PPAs and add new gas generation	Retire coal by 2031; demand reducing DSM; shift to more RE and ESS, extend gas tolling PPAs and no new gas generation	Retire coal by 2031; demand reducing DSM; accelerate RE and ESS, no gas-tolling PPAs and no new gas generation
Clean Energy	79%	84%	91%
RES achieved	58%	66%	77%
Nuclear	1,146 MW / 15.8%	1,146 MW / 15.7%	1,146 MW / 15.5%
Coal	0 MW / 0.0%	0 MW / 0.0%	0 MW / 0.0%
Natural Gas	5,440 MW / 16.7%	4,716 MW / 12.1%	3,581 MW / 5.5%
Renewable Energy (RE & DE)	9,830 MW / 41.2%	11,330 MW / 46.1%	13,755 MW / 53.5%
Demand Side Management	1,602 MW / 14.8%	1,602 MW / 14.7%	1,602 MW / 14.6%
Demand Response[4]	727 MW	777 MW	827 MW
Microgrids[4]	163 MW	163 MW	38 MW
Energy Storage[5]	4,852 MW	6,502 MW	10,552 MW
Market Purchase[6]	160 MW / 11.4%	160 MW / 11.4%	160 MW / 10.9%

[4] DR and microgrids are considered capacity resources and are not included in the energy mix.
[5] Energy storage does not create its own energy, so energy associated with it is reported under the source that provided the charging energy.
[6] Market Purchase capacity (MW) reflects firm power acquired through PPAs, while Market Purchase energy mix % includes firm purchases plus non-firm market wholesale purchases.

In the measurement of its renewable energy and clean energy goals, APS uses two types of metrics. To report our renewable energy share, we use the accounting conventions specified in the existing Arizona Renewable Energy Standard, under which each utility's share of renewables is expressed as a percentage of its retail sales,[7] relative to our total sales to customers. To measure its clean goals, APS also reports the share of each type of resource as a share of its total energy mix, including DSM. By including DSM in the energy mix, we can show its contribution to our total portfolio. This metric provides a more holistic presentation of our portfolio and treats all resources equally. One of the implications of the differences between these methods is that while our portfolios meet or exceed the 45% renewable goal by 2030 according to the state's RES accounting conventions, the reported share of renewables in our energy mix will appear lower. The difference between the two methods is further discussed in Chapter 7.

Load Forecast[8]

We developed our load forecast prior to onset of the COVID-19 pandemic. We recognize the serious impacts this pandemic has had on our customers and Arizona as a whole and are committed to supporting customers and communities through this challenge. We are monitoring the pandemic's effects and will evaluate its impacts on our load forecast once these effects are better understood. Further, we will keep stakeholders informed of our findings through stakeholder meetings and Action Plan updates.

Our base forecast projects that both annual peak demand and energy needs will increase at a compounded annual growth rate of 2.1% and 2.7%, respectively, during the IRP planning period of 2020-2035. Projected growth in the APS service territory is driven by four major factors: population growth, economic growth, data center growth and changing customer trends related to EVs and distributed generation.

Much of what drives our assumptions is the positive economic environment Arizona offers to businesses and the employees they attract. The state's focus on encouraging technology and economic development, as well as proximity to large population centers, has created many opportunities for Arizona to prosper. We recently announced several new manufacturing additions to our customer base and additional office space required for new businesses.

We recognize the importance of distributed generation, DSM/energy efficiency for our customers as residential and business energy needs grow. As such, our estimates include the effects of those resources. And, while working with our stakeholders, we collectively agreed to engage a third-party consultant to analyze DSM/energy efficiency impacts. Guidehouse examined a set of DSM programs with the greatest potential to help our customers and provided the results in an opportunity study. The study and its results are further explained in Chapter 2. While the study was a great start, we believe more work can be done to enhance DSM programs. We are committed to developing a tool that will allow us to better analyze these programs' potential for creating customer savings, managing system demand and reducing our carbon footprint.

Finally, we expect rooftop solar adoption to continue at approximately 100 MW per year through our planning period. Our forecast was developed in collaboration with our stakeholders and informed by Guidehouse.

[7] This approach to accounting for renewable generation is the same as the methods used in neighboring states for RPS accounting.
[8] APS is aware of the uncertainty surrounding our load forecast, related both to data center additions as well as macroeconomic influences such as the COVID-19 pandemic. As more information is available, we will inform stakeholders on any load forecast updates and adjustments to the associated resource needs through workshops and the Action Plan Update process.

ACTION PLAN HIGHLIGHTS: 2020-2024

We provide this Action Plan, which focuses on near-term developments and has more certainty over the next four to five-year window, to offer a view into potential resource needs and decisions through 2024 that will keep us on pace to reach our longer-term clean energy goals. This Action Plan will be updated in the future with additional details, including the results of outstanding and proposed RFPs.

Continued Expansion of Renewable Resources

Renewable energy is integral to our clean energy commitment and will require substantial ongoing investment. We expect the renewable energy additions will include wind and solar generation, plus investments in energy storage to help us reduce peak demands and utilize excess solar generation frequently available in the region.

RESOURCE ADDITIONS

As discussed above, our Action Plan identifies the need and commitment to add significant amounts of new renewable and energy storage resources to our generation mix. Currently, we are evaluating and developing RFPs expected to reduce our emissions and move us toward our ultimate goal of carbon-free electricity. Based on the additions identified in Table ES-1, we plan to add approximately 300-400 MW of renewables annually and 200-350 MW of storage additions annually beginning in 2022. However, given the uncertainty associated with the COVID-19 circumstances, we will keep stakeholders informed about updates to our plans or future forecasts through stakeholder meetings and Action Plan updates.

INVESTMENT IN ENERGY STORAGE

In February 2019, we announced an initiative to add 850 MW of battery energy storage by 2025. We remain committed to completing this initiative, but the timing and sequence of resource additions will vary due to the impacts of the April 19, 2019 equipment failure at the McMicken battery energy storage facility.

850mw of **battery storage** by 2025

We have advised bidders participating in the APS RFPs that involve storage to stop work on their proposals until further notice. Results of the McMicken investigation will inform our next steps, including any changes to design parameters that may be implemented for future batteries. We will continue to work with RFP participants on revised requirements and timelines.

REQUESTS FOR PROPOSALS (RFPs)

We have several RFPs outstanding at this time. These include:

- 2019 photovoltaic + storage (PVS) RFP requested 150 MW of PVS, which was paused pending the McMicken investigation
- 2019 photovoltaic (PV) Solar RFP requests 150 MW of battery-ready solar additions to the APS generation portfolio by 2021
- 2019 Wind RFP requests 250 MW of wind to be in service no later than 2022
- 2020 Demand Response (DR) RFP requests 75 MW of DR to be in service for summer of 2021

As these RFPs progress, we will keep parties appraised of the situation. Additionally, based on the expected energy and capacity needs shown in this IRP filing, we expect to issue an additional RFPs open to all resource types (all-source) sometime later this year.

INVESTMENT IN APS SOLAR COMMUNITIES

An expansion of rooftop solar installations for limited- and moderate-income Arizonans was approved by the Commission in August 2017. The program, under which APS owns and controls the generation, renewable energy credits and other program attributes, requires us to invest from $10 million to $15 million annually from 2018-2020 in rooftop solar for single-family and multifamily homes, allocating at least 65% of annual program expenditures to residential installations. Although the program focuses primarily on single-family homes, it also is available to multifamily housing, Title I schools, nonprofits aiding limited-income groups and government entities serving rural communities located in our service territory. The program is no longer open to new enrollees, but the ongoing evaluations and benefits to customers over the life of the system will help APS remain an innovator in integrating distributed solar onto the grid.

Innovation in Customer-Side Resources

We are offering programs that both help customers save money and energy and have the greatest resource value, with emphasis on load shifting and reducing peak load. The following programs focus on customer participation and simplicity by aligning technologies, rates and the grid's operational needs.

TAKE CHARGE AZ

EVs can help Arizona achieve an increasingly clean energy mix and cleaner air. Drivers are expected to have more than 130 EV models to choose from by 2022, but barriers to adoption still exist. We seek to make driving EVs convenient for participating customers by reducing range anxiety through access to more charging infrastructure.

The APS Take Charge AZ pilot programs offer free EV charging equipment, including installation and maintenance, to businesses, government agencies, nonprofits and multifamily communities. Participants pay for the electricity used to charge EVs, which they are encouraged to do when solar energy is abundant and energy prices are lower.

DSM IMPLEMENTATION PLAN

The APS 2020 DSM Plan (filed on December 31, 2019, amended May 18, 2020) consolidates and incorporates all elements of the 2018 and 2019 DSM Plans currently awaiting Commission review. Our 2020 DSM Plan continues our work to reshape DSM to better align with excess production of electricity in the middle of the day from solar generation and peak reductions in the evening when the sun has set. This translates to customer savings on bills and emissions reductions from using clean midday solar output. Among other measures, the plan proposes to continue the 2017 Demand Response, Energy Storage, Load Management program (see APS Rewards programs), which supports deployment of residential load management, demand response and energy storage technologies. The technologies help residential customers shift energy use and manage peak demand while reducing their energy costs.

Further, our 2020 DSM plan commits to funding our Limited Income Weatherization Program by an additional 50% and focuses on disadvantaged communities and limited-income multifamily properties. We are also expanding our education and outreach to help our customers make choices to reduce energy consumption when possible and shift energy usage to clean, lower-cost portions of the day when reduced consumption is not possible.

The 2020 DSM Plan also includes a proposed new pilot initiative for EV load management, new measures designed to address new data center loads with energy efficiency savings opportunities and proposed pilots for beneficial electrification measures that provide energy cost savings, emissions reductions and flexible electric loads that can be managed to flatten system load shapes by charging EVs during appropriate off-peak times.

APS REWARDS PROGRAMS

We have implemented a number of demand response and load management programs that facilitate emerging energy storage technologies such as grid-connected batteries, water heaters, and smart thermostats throughout our service territory. The increasing adoption of rooftop solar is rapidly changing system load shapes and creating need for more flexible resources to back up intermittent solar generation. Customer-sited batteries, water heaters, and thermostats, or distributed energy resources that support load management, demand response and load shifting to help meet these flexible resource needs by limiting peak demand and shifting energy use away from peak periods and toward midday, when rooftop solar production is highest.

The Rewards portfolio include the following programs and technologies, plus a platform to manage the devices:

- **Cool Rewards (demand response)** – APS has enrolled more than 19,300 connected residential smart thermostats in this demand response program in which we can operate the thermostats to reduce load during summer system peak events. By year-end 2020, We expect to be managing up to 35,000 connected thermostats in the Cool Rewards program.

- **Reserve Rewards (thermal storage) –** APS has enrolled 219 connected heat pump water heaters that shift water heating to the middle of the day when clean solar power can be used and reduce electric consumption during our evening peak.

- **Storage Rewards and Intermediate Feeder Energy Storage (battery storage) –** This includes 37 residential batteries deployed on targeted distribution feeders and 1-2 commercial-scale batteries and intermediate feeder energy storage deployed on targeted distribution feeders.

Short-Term Summer Peaking Needs

With the revised battery project timelines, we will likely use existing gas generation in the region as a bridging strategy to meet the projected load plus reserve margin. These short-term purchases ensure that we can meet summer reliability requirements and will be structured not to impact longer-term resource planning strategies. Currently, we expect short-term needs will be met with wholesale market purchases from a combination of existing merchant natural gas units, neighboring utilities and wholesale market participants.

Palo Verde Lease Extension

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. Through those agreements, APS retains the assets through 2023 under one lease and 2033 under two other leases. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years or return the assets to the lessors.

Natural Gas Transition

Managing customer affordability is an important element of the clean energy commitment. We will need to transition a large quantity of fossil fuel peaking capacity to clean peaking capacity over the next 30 years. This capacity is expensive to replace, and currently, energy storage is one of the few clean resources available in Arizona that can meet the need. In addition, natural gas prices are historically low and are expected to remain low into the foreseeable future.

Along with its affordability, natural gas is a source of reliable system capacity that will allow us to transition the fleet while maintaining a reliable safety net for the system should any new resource projects be delayed. Natural gas will help us to negotiate the best possible prices for new resources by providing flexibility in renewable and clean peaking capacity timing.

Natural gas-fired turbines are also increasingly showing the ability to be co-fired or exclusively fired by hydrogen. For these reasons, we recognize that the entire natural gas fleet should not be replaced overnight and expect to use gas as a transition fuel to a cleaner future while maintaining affordability.

Transmission Resources

With nearly 1.3 million customers across the state depending on us for reliable and affordable electric service, we rely on our network of transmission and distribution lines to safely deliver power. In planning the future development of our transmission infrastructure, we consider a broad range of technologies, including generation, transmission and distribution resources and non-transmission alternatives to address the challenges of an increasing array of resource types and geographies.

The 2020-2029 Ten-Year Transmission System Plan[9] includes approximately 26 miles of 230-kV transmission lines, 3 miles of 115-kV transmission lines and 38 new transformers. The total investment for the projects is estimated at approximately $590 million. Annual updates to the Ten-Year Transmission System Plan will address future needs and opportunities as they develop.

Transmission System Optimization

We recently announced on our OASIS website that we will use a new methodology for transmission system utilization. We will transition from a Rated System Path Methodology (MOD-029) to a Flowgate Methodology (MOD-030) for the calculation of Available Transfer Capability (ATC). This transition process will take approximately two years to complete and will result in more efficient use of and greater capacities for our transmission system, may result in some avoided future transmission build, may provide more flexibility in siting generation resources and will save customers money.

Extended Day Ahead Market (EDAM)

The Western electric grid is evolving significantly in order to reduce greenhouse gas emissions from electricity production. Changes to the wholesale market structure will be needed to integrate additional renewable resources reliably and economically onto the grid. We are working actively with the CAISO and other regional utilities in the design of a new market, called EDAM (Extended Day-Ahead Market), that takes advantage of the existing CAISO and Energy Imbalance Market (EMI) infrastructure. This new market would facilitate operation of renewable resource production in a manner that improves reliability and reduces curtailment when excess production occurs in some areas. We participated in a feasibility assessment with other EIM entities to evaluate extending EIM to this day-ahead market. While we have not yet made a decision to join the EDAM, APS is participating in the market design and stakeholder processes now underway. This again is an opportunity for the region to optimize its renewable energy resources and provide savings to customers.

MOVING FORWARD

We are excited about our clean energy future as well as the opportunity to make that journey with all of you – our regulators, our stakeholders, our communities and, above all, our customers. We have many challenges in front of us, including coal plant retirements, expiring PPAs and robust customer growth. The good news is that those same challenges provide an opportunity to begin transforming the resource mix we use to serve our customers to one that is cleaner and ultimately carbon-free. As a first step, we plan to focus our long-term commitments on renewables plus energy storage, demand response and DSM in the Action Plan window from 2020-2024. This allows us to begin the transformation to a clean energy future while maintaining reliability and affordability for our customers. Those same priorities will remain fundamental to how we will achieve the 2050 goal of a 100% clean energy mix.

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[9] Arizona Public Service Company 2020-2029 Ten-Year Transmission System Plan, Docket No. E-00000D-19-0007.

CHAPTER 1

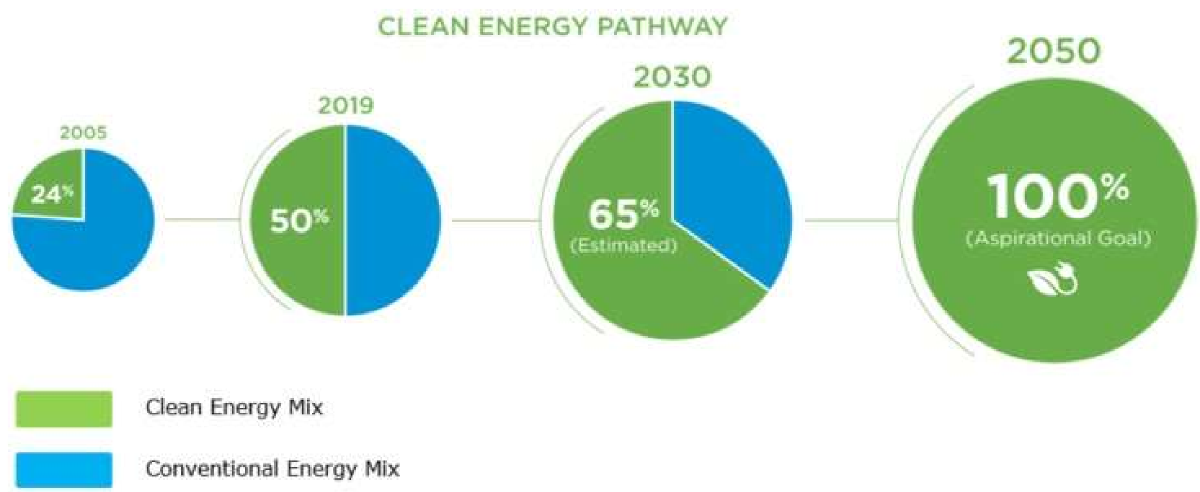
CLEAN ENERGY COMMITMENT & SUSTAINABILITY

Water Conservation
Emissions Control
Waste Management

CLEAN ENERGY COMMITMENT

On January 22, 2020, APS marked a historic milestone in its 134-year history as Arizona's largest electricity provider, setting a bold, three-part goal to provide a clean energy future for its customers.[1] The Company has been on a trajectory of increasingly clean energy through solar power innovation, major investments in energy storage technology, carbon-free nuclear operations and advances in energy efficiency solutions. Now the Company's clean energy pathway is set as the boldest clean energy goal of all Arizona electric companies, as well as one of the most ambitious in the country. The goal consists of the following:

- A goal to provide 100% clean, carbon-free electricity by 2050
- A nearer-term 2030 target of achieving a resource mix that is 65% clean energy, with 45% of our generation portfolio coming from renewable energy
- A commitment to end all coal-fired generation by 2031, seven years sooner than previously projected



The clean energy plan will be guided by sound science and focused on achieving environmental and economic gains – all while maintaining affordable, reliable service for customers. Collaboration with customers, regulators and other stakeholders is key to the plan's ultimate success. By working alongside those who believe in this vision, the Company expects to move forward together to keep Arizona clean, beautiful and thriving.

PATHWAY TO A 100% CLEAN FUTURE

On June 12, 2020, APS released its clean energy commitment that expounds upon how the Company will approach clean energy and take a leadership role in moving toward a carbon-free Arizona.[2] Along the journey to a carbon-free future, APS plans to ensure reliability and affordability through intelligent investments in renewable resources and developing technologies, nuclear power produced at Palo Verde

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[1] Pinnacle West Capital Corporation, *APS Sets Course for 100 Percent Clean Energy Future* (January 22, 2020). http://www.pinnaclewest.com/newsroom/company-news/news-release-details/2020/APS-Sets-Course-for-100-Percent-Clean-Energy-Future/

[2] "We're All in for Arizona: Our Clean Energy Commitment," https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Energy-Resources/CleanEnergyReport.ashx?la=en

Generating Station (Palo Verde), as well as energy efficiency and other programs for customers. Achieving this 100% clean goal while maintaining reliability of service at affordable rates for customers also will rely on:

- **Existing power sources** in the near term, including some natural gas, as APS makes a sensible transition to clean generating resources. In time, APS expects technological advances to eliminate the need to supplement renewable energy with even low-emitting carbon resources like natural gas in order to maintain reliable service around the clock at reasonable prices.
- **Continued modernization of the electric grid** as APS builds an advanced infrastructure that is more responsive and resilient, supports more renewables, minimizes outages and provides customers more choice and control over their energy decisions.
- **Energy storage solutions** to increase the effectiveness of renewable resources and provide more clean energy to customers after the sun has set. These will include APS's previously announced plans for an 850-megawatt expansion of large-scale energy storage, mostly paired with the Company's innovative solar farms.
- **Policy decisions** that leverage market-based technology and innovation and keep Arizona and its utility industry an attractive place to invest.
- **Electrification** of the state's different economic sectors, particularly the transportation sector and specific building applications. In addition to supporting affordability for utility customers, electrification will drive a cleaner environment and more energy-efficient operations throughout the economy.
- **Evolving regional and market-based solutions** such as participation in Western Energy Imbalance Market, which is saving customers tens of millions of dollars each year.

Policy decisions	Support policy decisions that leverage market-based technology and innovation to attract investment in Arizona
Existing power sources	Near-term use of natural gas until technological advances are available to maintain reliable service at reasonable prices
Evolving market-based solutions	Participation in the Energy Imbalance Market provides access to clean energy resources while saving customers money
Electrification	Electrification will drive a cleaner environment and more energy-efficient operations throughout the economy
Modernization of the electric grid	Continue to advance infrastructure that is responsive and resilient while providing customers more choice and control
Energy storage solutions	Storage creates opportunity to take advantage of midday solar generation and better respond to peak demand

COLLABORATION WILL BE FUNDAMENTAL TO SUCCESS

Based on stakeholder feedback of prior Integrated Resource Plans and the Arizona Corporation Commission's efforts to update the state's energy rules, APS initiated a thorough review of its generation mix and future plans. APS spent more than a year engaged with a variety of stakeholders including customers, business organizations and non-governmental organizations. Our plans reflect those experiences and discussions.

Collaboration with stakeholders and regulators will be key to the plan's ultimate success, with transparency regarding APS's roadmap and progress through Arizona's established process of Integrated Resource Plans. Flexibility, reliability, affordability and customer focus will remain fundamental planning principles that will guide the addition of carbon-free resources at a reasonable cost and on pace and scale with customers' growing and changing energy needs.

Meeting our clean energy goal by 2050 will mean transitioning away from coal. APS does not take this transition lightly, and the Company is committed to working with its employees and stakeholders on the economic impact and other effects of retiring those assets.

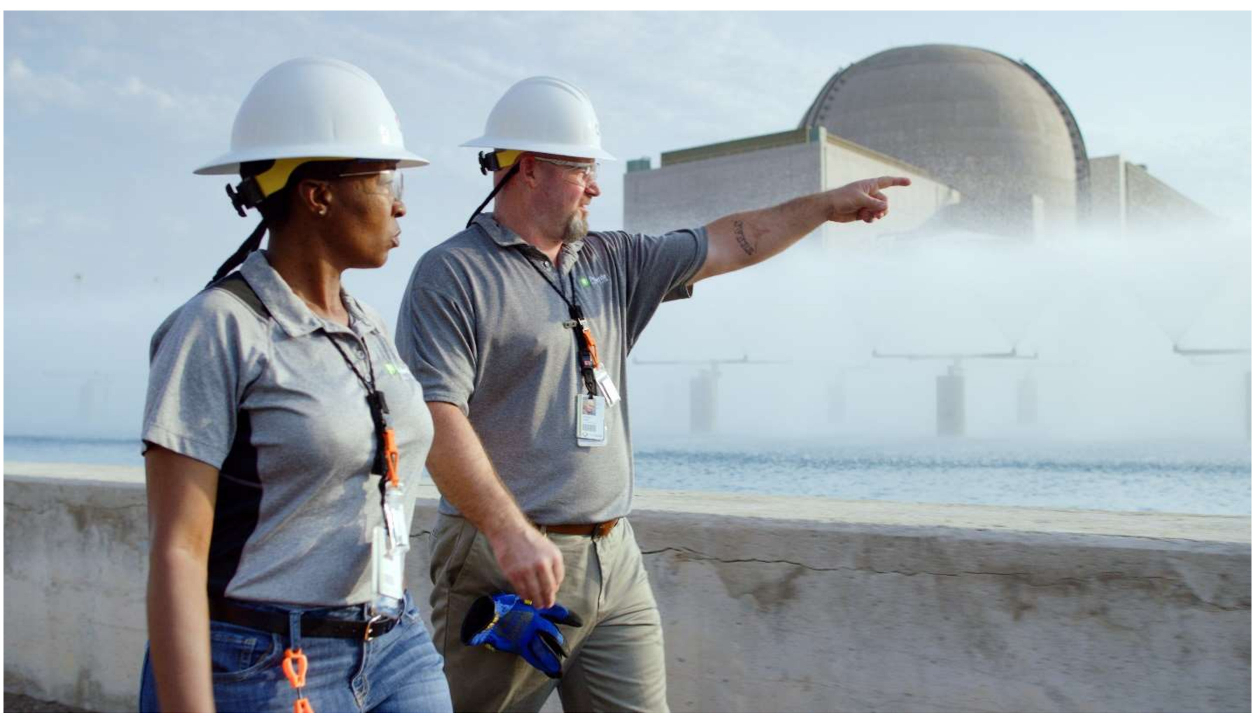
APS also acknowledges that some of the solutions needed to achieve the goal are nascent or even yet to be developed, and that realizing the full potential and benefits of a completely clean energy mix will take partnerships. APS's progress to date and developing this goal would not have been possible without the support from an array of stakeholders that include Arizona's universities and non-governmental organizations.

The benefits of a 100% clean energy portfolio include helping customers achieve their own sustainability goals and attracting more employers to Arizona who want to be served fully by carbon-free resources at a reasonable cost and without compromising reliability.

SUSTAINABILITY

Sustainability, in its purest form, is about careful use of resources so that APS is able to successfully conduct operations today and long into the future. The most sustainable companies adhere to Environment, Social and Governance (ESG) principles that guide decision-making and help achieve shared value for communities, the economy and the environment. At APS, it means doing the work to strike a balance between providing reliable, affordable energy and being responsible stewards of the environment. The sustainability activities of APS operations are founded on the principle that promoting Arizona's vibrant economy, protecting a healthy environment and supporting stable communities will strengthen the Company's service territory and the state for future generations.

Sustainability is also about transparency. APS believes it is important to disclose its carbon management strategies and GHG emissions as well as its water management actions to customers, investors and other stakeholders. The Company voluntarily reports annually to the CDP (formerly the Climate Disclosure Project), a global nonprofit organization that collects and analyzes environmental data for investors to use in financial decisions. CDP reporting provides a benchmark to evaluate how well APS manages its impacts on the environment and identifies opportunities for improvement. In 2019, APS was one of only ten American companies to make the prestigious "A List" for both Water and Climate.



In 2019, APS produced more than 50% of its energy mix from carbon-free resources including renewable energy, energy efficiency, other DSM programs and, most importantly, the carbon-free nuclear generation from Palo Verde. The nation's largest power producer of any kind, Palo Verde produced 31.9 million MWh in 2019 – the only U.S. generating facility to produce more than 30 million MWh in a single year. Over the course of the Planning Period, the Company's commitment to clean energy will continue as it evaluates further advances in water conservation, emissions control and waste management programs and technologies, in addition to supporting customers' increasing interest in DSM solutions.

WATER CONSERVATION

Arizona's water challenges are balanced between two realities: increasing demand for water due to high growth rates and limited supply of water given the arid conditions of the Desert Southwest. The state's electric utility industry has long recognized these challenges and continuously engages in water conservation efforts that have resulted in Arizona power plants consuming less than 3% of the state's water supply. APS's achievements in this effort include the largest water/energy project in Arizona's history: Palo Verde became the first nuclear power plant in the world not bordering a large body of water to use reclaimed water. APS continues to explore innovative solutions in pursuit of the "right water for the right use." Towards that end, each APS power plant has a unique water strategy, which is developed to promote efficient and sustainable use of water and reliability of water supplies. Other efforts such as retiring or upgrading water-intensive power plants, increasing the use of renewable energy and implementing DSM programs add to APS's overall water conservation.

EMISSIONS CONTROL

APS strives to cost-effectively reduce the impact of its operations on the environment and communities that we serve. APS has recently completed (a) the installation of state-of-the-art air pollution controls at the Four Corners Power Plant, (b) the replacement of older gas-fired turbines with new, modern turbines and modernized air pollution controls as part of the Ocotillo Modernization Project, and (c) the installation of upgraded combustion technology that increased output from the Redhawk Power Plant (Redhawk) without increasing emissions of nitrogen dioxide. APS is currently evaluating installation of additional air pollution controls on two of its combined cycle units at the West Phoenix Power Plant.

WASTE MANAGEMENT

APS's waste management efforts encompass the responsible handling of discharges of wastewater and streams originating from fly ash and bottom ash handling facilities, solid waste, hazardous waste and coal combustion products, which consist of bottom ash, fly ash and air pollution control wastes. APS currently disposes of coal combustion residuals in ash ponds and dry storage areas at Cholla and Four Corners and sells a portion of its fly ash for beneficial reuse as a constituent in concrete production.

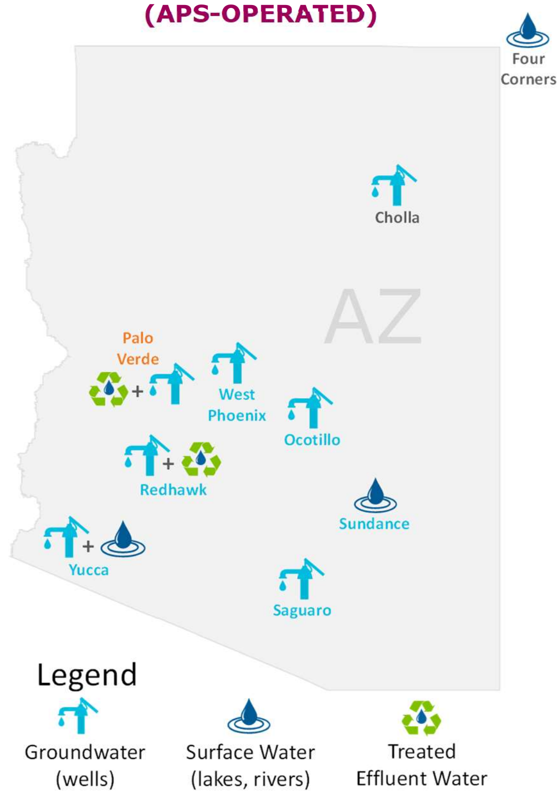
Approximately 47% of the non-hazardous waste tracked through the Company's Investment Recovery group is recycled. In terms of hazardous waste, APS has achieved reductions since 2002, and each year since 2006, APS has successfully generated 88%-97% less hazardous waste from routine activities than what was produced in 2001.

High-level nuclear waste (i.e., spent fuel) continues to be stored on-site at Palo Verde. APS has identified and implemented the safest, lowest maintenance and effective interim storage options pending a permanent solution from the U.S. Department of Energy. Low-level nuclear waste is safely shipped off-site for disposal.

Water Conservation

Water is growing in importance as a factor in assessing the viability of new energy projects for all utilities. Utilities operating in water-constrained areas – such as APS's service territory – face greater challenges. To meet those challenges while maximizing the use of renewable water resources and minimizing the use of non-renewable resources, it is important to consistently monitor water use, both in terms of the amount of water used and water intensity (gallons per MWh). Reductions for the period 2012–2035 are associated with unit retirements at APS owned and operated plants Saguaro, Four Corners, Cholla and Ocotillo, increased reliance on renewable energy that does not use water (wind, PV solar) and increased energy efficiency.

FIGURE 1-1. WATER SOURCE BY FACILITY (APS-OPERATED)



We will continue to conduct water efficiency audits of power plants, implement leak reduction programs and ensure equipment is functioning as designed, which will help the Company achieve conservation of groundwater resources. In 2016, APS developed and implemented a groundwater conservation strategy designed to reduce fleetwide consumption of groundwater by 8% compared to the reference year 2014. Goals of 10%, 12%, and 14% reductions were established for 2017, 2018, and 2019, respectively. In 2019, the actual reduction was 22.4% below 2014 consumption. This strategy supports an APS Tier I metric entitled Conservation of Non-Renewable Water Supplies, which is achieved by implementing water conservation measures at APS plants.

The use of reclaimed water at both Redhawk and Palo Verde are examples of water strategies that have most clearly defined APS's water footprint in Arizona. In 2019, 71% of all water used by the APS fleet was reclaimed water, which frees up fresh water for other uses by the communities we serve. Between 2019 and 2035, APS will further reduce use of groundwater, increase the proportion of treated effluent to support power generation, and use very small quantities of surface water at Sundance.

APS STAKEHOLDER ENGAGEMENT

To bolster water efficiency efforts and improve communication with other water stakeholders, APS is a member of the Governor's Water Augmentation, Innovation, and Conservation Council, the Kyl Center for Water Policy at the Morrison Institute, the Groundwater Users Advisory Council, the Post-2025 Active Management Area Committee, the Colorado River Water Users Association, the Water Reuse Association and the ADWR 5th Management Plan Workgroup. Participation in these water stakeholder groups improves the Company's understanding of water needs and trends and allows it to communicate and model plans to support sustainable water practices.

OUTLOOK FOR WATER INTENSITY IN APS OPERATIONS

Over the 2020-2035 Planning Period, water intensity is expected to decrease due to:

- Increased penetration of renewable energy resources;
- Increased penetration of energy efficiency;

- Retirement of older, water-intensive units;
- Technological advancements in new power plants that use efficient water-cooling strategies such as hybrid cooling systems; and
- Implementing water conservation measures at existing plants.

A forecast of the reduction in water intensity measured as gallons per MWh for the Resource Plans is included in the response to Rule D.17.

APS WELL SURVEY PROGRAM

Water Resource Management undertook a statewide survey of the location and condition of wells associated with APS power plants and other properties in Arizona and New Mexico. This evaluation included production wells, monitoring wells, remediation wells, drinking water wells, agricultural wells, cathodic protection wells and grounding wells. Wells were evaluated for safety, degraded operational condition and potential to allow aquifer cross-contamination or surface water intrusion. The intent was to map all APS well infrastructure and to identify the current status of each well, with a focus on identifying wells in need of maintenance or abandonment. Eleven of the highest priority wells were abandoned in 2019 and another 41 wells were planned for abandonment in 2020. This program will continue to evaluate future needs for maintenance or abandonment consistent with regulatory requirements.

WATER OVERVIEW BY FACILITY

APS manages the water use at nine APS-owned/operated facilities. The focus is on non-renewable water (i.e., groundwater) because this supply is at the greatest risk of depletion and is a significant source of supply at seven of nine APS power plants.

NUCLEAR

PALO VERDE

Source: Treated effluent (reclaimed) water

With operating licenses in place for Units 1, 2 and 3 through June 2045, April 2046 and November 2047, respectively, the current water supply contract ensures a reliable supply will be available through 2050. We will evaluate a second license renewal request for an additional 20 years in the future. Opportunities include working with state and federal agencies as well as West Valley communities to develop alternative water supplies, which can be used directly or indirectly through recharge and recovery.

Palo Verde uses treated effluent for cooling water and a comparatively small quantity of groundwater for drinking water and industrial process water. Avoidance of groundwater use as cooling water is very important because two adjacent power plants, Mesquite and Arlington Valley, rely upon groundwater from the same aquifer. APS (for Palo Verde and Redhawk), Mesquite and Arlington Valley send a report every five years to the ACC, ADWR and U.S. Geological Survey (USGS) concerning subsidence and land fissure development around the four power plants. Use of effluent by Palo Verde and Redhawk in lieu of groundwater reduces the probability of subsidence in the area.

In 2016, Palo Verde's Water Reclamation Facility built a seventh treatment train that provides redundancy and allows rehabilitation of existing equipment with no loss of treatment capacity. In 2019, rehabilitation of the original six treatment trains was in progress. This provides greater reliability of treated effluent for use at Palo Verde and Redhawk.

COAL

FOUR CORNERS

Source: Surface water from the San Juan River

Following a drought in 2000, a shortage sharing agreement was executed between the Bureau of Reclamation (BOR) and the parties utilizing San Juan River surface water as their water supply. The current agreement will expire in December 2020, and plans are in place to continue this significant partnership that reduces the probability of adverse impacts to participants in the event that a shortage is declared on the Colorado River. In 2019, APS worked with the BOR and other major water users on the San Juan River to keep more water in Navajo Reservoir, ensuring that all of the water needs, including environmental needs, are met while minimizing the potential of future water shortages.

In 2017, APS implemented commitments under the National Environmental Policy Act to support endangered fish and bird populations near the Four Corners Power Plant. Actions in 2019 included providing funds to the National Fish and Wildlife Foundation to support fish stocking and studies, maintaining a non-native fish control structure on Morgan Lake, supporting development of a fish ladder around the APS pump station in the San Juan River that will improve endangered fish passage, coordinating river pumping with fish stocking and spawning, and performing endangered bird studies.

CHOLLA

Source: Groundwater from 18 production wells located on both sides of the Little Colorado River

To mitigate concerns of the wells' proximity to the Little Colorado River, a Cholla groundwater flow model was developed in 2014 and a groundwater monitoring program has been conducted since 2012. Further development of this model is ongoing and is expected to minimize possible adverse impacts on groundwater levels, water quality and surface water flows. Cholla's groundwater modeling and water quality sampling has enabled development of a Cholla Wellfield Operations Plan that has identified variable water quality in wells and directs plant staff to use higher quality water first. This optimizes the water quality available for use as cooling water, drinking water and industrial process water, and also results in reduced overall water consumption.

PacifiCorp, a Cholla Power Plant participant, announced in 2019 that they would cease operation of Unit 4 by the end of 2020. This will reduce water consumption at Cholla by approximately 40% and the remaining water consumption for Cholla generation will be eliminated by 2025. APS is working closely with the Coconino Plateau Watershed Partnership to understand groundwater conditions in Northern Arizona and partner with other stakeholders to protect water supplies.

NATURAL GAS

OCOTILLO

Source: Groundwater in the Phoenix Active Management Area

As part of the 2019 Ocotillo Modernization Project, APS replaced the two existing 1960s-era steam units with five new quick-start combustion turbines (CTs) that incorporate hybrid (wet/dry) cooling towers into the design. The new CTs used 164 gallons/MWh in 2019 compared to the steam unit consumption in 2018 of 827 gallons/MWh, thereby reducing the quantity of groundwater required to support plant operations. To increase reliability of water supply, Ocotillo's existing wells were rehabilitated, and a new well was placed in service in 2019.

WEST PHOENIX

Source: Groundwater in the Phoenix Active Management Area

The West Phoenix Power Plant utilizes a zero-liquid discharge (ZLD) brine concentrator and evaporator that allows reclamation and reuse of treated water, reducing reliance on groundwater. A new well was placed into service at West Phoenix in 2019, increasing water delivery reliability at the plant.

REDHAWK

Source: Treated municipal effluent (reclaimed water) provided by the Palo Verde Water Reclamation Facility (PVWRF) as the primary cooling water supply plus groundwater.

The effluent is delivered to the Redhawk reservoir with a minimum 20-day supply at 100% capacity factor and is ready for use. Groundwater reliability was enhanced in 2019 with equipment installation in the new East Well.

In 2016, the PVWRF built a seventh treatment train that provides redundancy and allows rehabilitation of existing equipment with no loss of treatment capacity. In 2020, rehabilitation of the original six treatment trains was in progress, with two complete and the third expected to be complete in September. This provides greater reliability of treated effluent for use at Palo Verde and Redhawk.

SAGUARO

Source: Groundwater from four on-site wells

Decommissioning of the two steam turbines has significantly reduced the need for water to support generation. However, smaller quantity water needs persist for the plant's combustion turbines. Saguaro Well #5 was drilled in 2019, increasing water delivery reliability.

SUNDANCE

Source: Surface water

In addition to its rights for excess Central Arizona Project (CAP) water, APS has purchased as an alternative 5,000 AF of water from the Gila River Indian Community (GRIC) and entered into a recovery and exchange agreement with the GRIC for the next 45 years, continuing its reliance on renewable surface water.

YUCCA

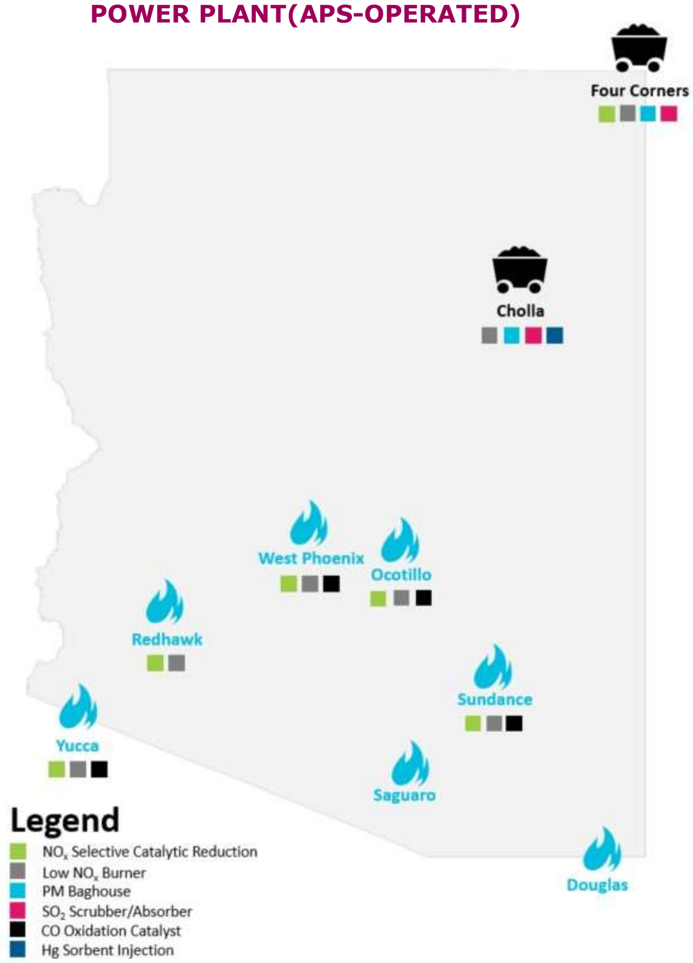
Source: Surface water from the Colorado River and groundwater from three on-site wells

A new well was drilled in 2014 and placed into service in 2015. This well is out of the Colorado River accounting surface, pumps groundwater and will meet the needs of the plant in the event of a Colorado River shortage. APS entered into an agreement with the CAP and USBR to forego use of 5^{th}-6^{th} priority surface water rights and instead use groundwater whenever possible, conserving the surface water in Lake Mead as a hedge against future shortage.

Emissions Control

APS is working to reduce its carbon footprint through the Company's Commitment to Clean Energy, which relies upon the addition of low- and zero-emitting resources to its portfolio mix and the cessation of burning coal by 2031. See Chapter 7 – Portfolio Analysis for a carbon analysis of the three portfolios reviewed in the 2020 IRP. Reduction in other pollutants, such as mercury (Hg), nitrogen oxides (NOx), sulfur dioxide (SO2), particulate matter (PM) and carbon monoxide (CO) is managed through installation of various environmental controls and other efforts. Since 2005, overall Company-wide emissions have been reduced as a result of the retirement of generating units at some facilities, the installation of new air pollution controls at existing units and investments in state-of-the-art air pollution control technology at new and modernized facilities. A recent example is the Ocotillo Modernization Project, which began operation in 2019. The project replaced two 1960s-era natural gas-fired steam generating units with five new gas-fired turbines that are equipped with state-of-the-art air pollution control technology. As a result, the energy generation capacity at the site more than doubled while the NOx and CO emissions from the facility were cut by more than half. Figure 1-2 provides a visual overview of the air pollution controls that are in existence for the facilities within the Company's fossil fuel-fired fleet of generating facilities.

Figure 1-2. AIR POLLUTION CONTROLS BY POWER PLANT(APS-OPERATED)



NITROGEN OXIDES (NOx)

Nitrogen oxides are a family of highly reactive gases that form when fuel is burned at high temperatures. The pollutant appears as a brownish gas and is known to react with Volatile Organic Compounds (VOC) and heat to form ground-level ozone, often referred to as smog. In 2016, APS reported a total of approximately 14,866 tons of NOx emissions for all APS-owned facilities. By the end of 2019, and as a direct result of emissions controls at Four Corners, that number was cut by approximately 56% to approximately 6,547 tons for all APS-owned facilities. All of APS's coal-fired facilities and many of its natural gas-fired facilities, especially those that impact or are impacted by nearby ozone non-attainment areas, have installed at least one of the air pollution controls detailed below.

LOW NOx BURNERS (LNB)

By volume, dry air from the earth's atmosphere contains approximately 78% nitrogen in the form of N_2. At high temperatures, the naturally occurring nitrogen molecules break apart and react with oxygen to form NOx. LNBs effectively control this reaction by changing the characteristics and location of fuel combustion as well as the peak flame temperature. LNBs are one of the better values in air pollution control, providing a high level of removal efficiency of NOx at a lower overall cost than other NOx control options.

APS-owned and operated facilities that currently employ LNB technology:

- Cholla
- Four Corners
- Ocotillo
- Redhawk
- Sundance
- West Phoenix
- Yucca

SELECTIVE CATALYTIC REDUCTION (SCR)

SCR is a post-combustion control device that utilizes a catalyst and a chemical reaction with ammonia to reduce emissions of NOx into water, oxygen and nitrogen. In the United States, SCR has been applied to both coal- and natural gas-fired electrical utility boilers and turbines, effectively reducing overall emissions by 70% to 90%. SCR also results in the emission of small concentrations of ammonia, often referred to as ammonia slip, as the chemical reaction performs best in the presence of excess ammonia. SCR is the most expensive of all NOx air pollution control strategies.

APS-owned and operated facilities that currently employ SCR technology:

- Four Corners
- Ocotillo
- Redhawk
- Sundance
- West Phoenix
- Yucca

OVERALL BENEFIT

In 2007, APS reported more than 9,801 tons of NOx emissions from the units it owns at the Cholla Power Plant and more than 20,406 tons of NOx emissions from the units it owns Four Corners Power Plant, respectively. That same year, all APS-owned units were responsible for a total of 35,953 tons of NOx emissions. As a result of air pollution control projects at several facilities, including Cholla and Four Corners, the permanent retirement of Unit 2 at Cholla, the permanent retirement of Units 1, 2 and 3 at Four Corners, and the replacement of steam generating units at Ocotillo, the entire APS-owned fleet emitted just 6,547 tons of NOx emissions in 2019. The fleet-wide emissions rate represents an overall reduction of approximately 82% when compared to 2007 levels. It will now take the entire APS owned fleet approximately five and a half years to emit the same amount of NOx that had been emitted in just a single year.

SULFUR DIOXIDE (SO2)

Sulfur dioxide is part of a larger family of reactive gasses that form as a result of burning fuels that contain sulfur. Because natural gas is inherently low in sulfur, coal- and oil-fired facilities are the most likely to generate SO2 emissions. SO2 in the atmosphere contributes to the formation of acid rain and can react with other compounds in the atmosphere to form fine particles that create visibility impairment, or haze, throughout the United States. In 2016, APS reported a total of 3,798 tons of SO2 for all APS-owned facilities. By the end of 2019, and as a direct result of additional controls at Four Corners, SO_2 emissions have decreased another 40%, to a total of 2,275 tons for all APS-owned facilities. A total of 1% of all SO_2 emissions come from APS-owned natural gas-fired generation.

SO2 SCRUBBER/ABSORBER

SO_2 scrubbers and absorbers, sometimes referred to as flue gas desulfurization, typically use aqueous limestone slurries to create a chemical reaction that eliminates the gaseous SO_2. This acid-base reaction forms calcium sulfide, which is absorbed by the liquid in the scrubber, resulting in significant control of the SO_2 acid gases that form as part of combustion. Because natural gas is inherently low in sulfur content, SO_2 scrubbers and absorbers are only used on coal-fired generating stations in the APS fleet. Scrubbers also provide an additional benefit by reducing particulate matter emissions.

Both APS-owned coal facilities, Four Corners and Cholla, include SO_2 scrubber or absorber technology.

OVERALL BENEFIT

Improvement in pollution control at APS's coal facilities have resulted in significant reductions of SO_2 throughout the fleet. In 2007, prior to its voluntary emissions reduction program, APS owned Cholla units reported more than 12,504 tons of SO_2 emissions, and APS owned Four Corners units reported more than 3,777 tons of SO_2 emissions. As a result of the retirement of Unit 2 at Cholla and Units 1, 2 and 3 at Four Corners, the use of SO_2 scrubbers and absorbers on the remaining units and load demands, total SO_2 emissions from both facilities were reduced in 2019 to approximately 1,522 and 1,169 tons, respectively. Total SO_2 emissions from both facilities are expected to remain approximately the same in future years, representing more than 83% overall reduction since 2007.

PARTICULATE MATTER (PM)

Particulate matter, also known as particle pollution, is a term that describes the mixture of solid particles and liquid droplets that are found in the air. Unlike gaseous pollutants, particulate matter is regulated by size. Larger particles, called PM_{10}, are often associated with activities that break up the earth's crust or generate dust. Smaller particles, called $PM_{2.5}$, are often associated with the burning of a fuel and are commonly referred to as soot. Both forms of particulate matter have been a focus of the Clean Air Act since its inception. Combustion of natural gas produces almost no PM emissions. Coal-fired facilities are the primary contributor to PM stack emissions. In 2019, APS reported a total of approximately 578 tons of PM_{10} emissions for all owned facilities. The most common control device is a baghouse.

BAGHOUSE

A baghouse is an air pollution control device that is specifically designed to remove particulate matter by passing the exhaust gas from a process through a fabric filter or series of fabric filters that resemble a large sock or bag. These socks or bags physically collect the particulates in the folds or on the surface of the fabric. Self-cleaning mechanisms are used to periodically remove the dust cake from the surface of the fabric to ensure optimal removal efficiency.

APS-owned and operated facilities that currently employ baghouse technology:

- Cholla Power Plant
- Four Corners Power Plant

CARBON MONOXIDE (CO)

Carbon monoxide is a colorless, odorless gas formed through the incomplete combustion of fuel. Problems with concentrations of CO in the atmosphere have largely been resolved through the proliferation of modern air pollution controls.

CO OXIDATION CATALYST

CO oxidation catalyst is a post-combustion control device that utilizes a precious metal catalyst (typically platinum) and heat to achieve the maximum conversion of carbon-based compounds, including carbon monoxide gas, to carbon dioxide.

APS-owned and operated facilities that currently employ CO oxidation catalyst technology:

- Ocotillo
- Sundance
- West Phoenix
- Yucca

MERCURY (Hg)

Mercury is a naturally occurring chemical element that is found in rock and other materials in the earth's crust, including deposits of coal. Because mercury does not degrade in the environment, most mercury emitted into the atmosphere eventually deposits into land or water bodies.

Arizona utilities have been working collaboratively with the Arizona Department of Environmental Quality to reduce mercury emissions since 2007, when they agreed to a state mercury emissions reduction program that set a long-term goal of complying with EPA's final Mercury Air Toxics Standard or a 90% emissions control by the end of 2016. APS also selected an interim goal of achieving a 50% control for Cholla by 2011, which it accomplished. In 2016, total mercury emissions from APS owned coal-fired generating units at Cholla and Four Corners was approximately 51 pounds. By 2019, total mercury emissions from APS owned coal-fired generating units at Cholla and Four Corners decreased to approximately 23 pounds.

TABLE 1-1. MERCURY EMISSIONS

APS-OPERATED FACILITY	2019 MERCURY EMISSIONS
Cholla	10 pounds
Four Corners	13 pounds
TOTAL	23 pounds

ACTIVATED CARBON INJECTION

Activated carbon injection is a post-combustion control technology that typically introduces activated carbon into a gas stream in an effort to reduce emissions of mercury. The activated carbon is injected into the gas stream upstream of the particulate matter control device to absorb mercury before being captured and removed by the particulate matter control device.

Cholla is the only APS-owned and operated facility that currently employs activated carbon injection for mercury control. Four Corners has been able to achieve significant mercury emissions reductions and comply with EPA's Mercury Air Toxics Standard without the need of additional controls. APS achieved these emissions reductions by improving the method in which coal is combusted in the boiler, introducing electrostatic chemistry in the baghouse and utilizing the SO2 scrubber's ability to remove all but the remaining elemental mercury.

SULFUR HEXAFLUORIDE (SF6)

SF6 is an inorganic, colorless, odorless, non-flammable, non-toxic but extremely potent greenhouse gas with a warming potential that is more than 23,900[3] times greater than CO2. SF6 is used worldwide due to its outstanding insulation properties and its capacity for arc quenching, a critical safety feature.

In 2016, APS reduced its SF6 emissions by implementing process, procedure and tracking improvements including an active breaker replacement program[4]. Because of the high warming potential, small emissions of SF6 can have large impacts. To account for the difference, the relatively small emissions are scaled up to equal the number of tons of CO2 that have the same warming potential. Through its ongoing efforts, APS achieved an almost 52% reduction in SF6 emissions year-over-year, from 60,285 equivalent tons of CO2 emissions in 2015 to 29,162 equivalent tons of CO2 in 2016. APS has continued to refine these efforts, with excellent results. In 2019, SF6 were reduced to just 10,683 equivalent tons of CO2, an 82% overall decline since the start of the effort[5].

TABLE 1-2. SF6 EMISSIONS

YEAR	SF6 EMISSIONS EQUIVALENT TONS OF CO2
2015	60,285
2016	29,162
2017	16,931
2018	10,773
2019	10,683

Waste Management

Sustainability is about being a good steward of resources, using only what is needed today and keeping the balance to meet similar needs in the future. For APS, this translates into efficiently extracting the value from those resources that are necessary to deliver clean, affordable and reliable energy to meet customer demand. Towards that end, APS maximizes the use of its fuels and supplies and works not only to minimize or eliminate waste where possible but also to responsibly manage waste that is generated by the Company's processes (e.g., waste management).

COMMON WASTE MANAGEMENT

APS's Investment Recovery group is a leader in corporate recycling and landfill use reduction. Waste materials are recycled through specialized streams (such as scrap metal and E-waste) as well as comingled, which is a single-stream recycling of common waste materials. APS continues its efforts to understand and limit its impact on the environment by tracking wastes diverted through the APS forestry program and by capturing the quantities of vegetation that are removed and able to be mulched. The Investment Recovery team also helps smaller Arizona communities that lack adequate recycling services, such as Douglas, Globe and Wickenburg, recycle and recover resources[6].

APS continues to explore opportunities for increased redeployment of equipment internally and makes an effort to send material out for refurbishment, resale or donation before making it a waste. These opportunities extend the life of the Company's resources, reduce its contribution to landfills and allowed

[3] Changes in Atmospheric Constituents and in Radiative Forcing. *Climate Change 2007: The Physical Science Basis* 2007. https://www.ipcc.ch/site/assets/uploads/2018/02/ar4-wg1-chapter2-1.pdf
[4] CDP 2017 Climate Change 2017 Information Request: Pinnacle West Capital Corporation. http://s22.q4cdn.com/464697698/files/doc_downloads/performance_summary/ProgrammeResponseClimate-Change-2017.pdf NOTE: Source reports emissions in metric tons. Converted to short tons for consistency in the report. Equation is Metric Tons * 1.1023
[5] CDP Pinnacle West Capital Corporation – Climate Change 2019. http://s22.q4cdn.com/464697698/files/doc_downloads/2019/corporateresponsibility/Programme-Response-Climate-Change-2019.pdf NOTE: Source reports emissions in metric tons. Converted to short tons for consistency in the report. Equation is Metric Tons * 1.1023
[6] Pinnacle West Capital Corporation, *Waste Recycling & Investment Recovery* (April 2020). http://www.pinnaclewest.com/corporate-responsibility/environment/waste/default.aspx

APS to recover approximately $1.8 million, while donations benefitted nonprofit organizations including Goodwill of Arizona and Treasures for Teachers.

HAZARDOUS WASTE MANAGEMENT

APS has been proactively reducing its hazardous waste for a number of years. After generating more than 240 tons of hazardous waste in 2001, APS has undertaken efforts to reduce its hazardous waste generation. Since 2006, APS's annual routine hazardous waste reduction efforts achieved from 88% to 97% reductions from 2001 levels, and since 2015, APS's routine hazardous waste has remained more than 96% below 2001 levels.

Routine activities do not include episodic events and remain very well controlled. Episodic generation can occur at sites that are routinely small or very small quantity generators of hazardous waste. These episodic events are usually the result of non-routine activities that cause the site to generate hazardous waste over the limits for their normal categorization. APS experienced episodic generation in 2017 through 2019. In 2019, two non-routine projects generated additional hazardous waste. The first project was replacement of spent selective catalytic reduction material from the air pollution control devices at Yucca Power Plant, and the second project was the decommissioning of a large fuel tank that entailed a lead abatement project.

APS was one of the first U.S. utilities to recycle solar panels without generating any hazardous waste materials

This commitment was underscored in the summer of 2016 when several of APS's solar facilities experienced heavy damage due to high winds and hail from a monsoon storm. Samples revealed that approximately 200 tons of damaged solar panels would qualify as hazardous waste if they were simply to be disposed. APS's review of its fleet of solar assets indicates that as many as half of its solar panels could also qualify as hazardous waste if not recycled in the event of disposal. Through exhaustive research, APS identified a single recycling Company in the United States capable of handling and completely recycling the solar panels without generating any hazardous waste. This breakthrough ensures APS's continued success in reducing the amount of hazardous waste ending up in landfills each year.

COAL ASH MANAGEMENT[7]

When coal is burned to produce electricity, it generates several by-products, one of which is coal combustion residuals (CCR), generically referred to as "coal ash." Coal ash is primarily made up of rocks, minerals and other non-combustible, natural materials that are mixed in with the coal when it is mined from the earth. Cholla and Four Corners consume about 6 million tons of coal each year, yielding approximately 1.2 million tons of CCR annually.

APS manages to the reuse of coal ash to help reduce our environmental footprint and reduce costs. To prevent coal ash from being landfilled, more than half is sold to cement manufacturers who use it as an essential component in concrete production. In 2019, Cholla and Four Corners collectively generated a little more than 1.2 million tons of coal ash and sold more than 715,000 tons, preventing more than 58% from being landfilled. These sales also benefit air quality, as the quantity sold resulted in a reduction of more than 431,000 tons of CO2, the equivalent of removing more than 84,000 vehicles from the road.

APS has plans to cease the combustion of coal at Cholla by mid-2025 and Four Corners by the end of 2031. APS is currently monitoring groundwater quality around its coal ash impoundments, implementing

[7] Pinnacle West Capital Corporation, *Waste Recycling & Investment Recovery* (April 2020). http://www.pinnaclewest.com/corporate-responsibility/environment/waste/default.aspx

projects to minimize the impacts associated with CCR management, and has immediate plans to reduce the overall number of regulated coal ash impoundments at both facilities from ten to five. APS remains committed to finding beneficial reuses for CCR and to reduce our overall coal ash management footprint.

NUCLEAR WASTE MANAGEMENT

Like all nuclear power plants, Palo Verde produces nuclear waste in the form of spent fuel – commonly referred to as high-level waste – along with low-level waste such as used protective clothing, filters and other contaminated items. There are currently no options for disposal or reprocessing of high-level waste. As a result, Palo Verde continues to move spent fuel from its spent fuel pools to dry cask storage. Dry cask storage is safe, secure and low maintenance and an effective interim, on-site storage option for nuclear waste that the Company will continue to use until the U.S. Department of Energy meets its obligation to provide a permanent nuclear waste storage facility. Low-level waste, including low-level water waste, is packaged in proper containers and shipped for disposal in permitted disposal facilities.

POLYCHLORINATED BIPHENYLS (PCB) MANAGEMENT

APS has been implementing a PCB management program in an effort to manage and reduce the amount of PCB and PCB-contaminated equipment. The company has successfully reduced the use of PCBs in electrical equipment by targeting suspected equipment based on manufacturer information and the serial numbers. Since 2000, APS removed 17,690 pieces of equipment from its distribution and substation systems, resulting in disposal and replacement of more than 4 million pounds of PCB-containing material. APS expects to continue its program through the Planning Period.

A Sustainable Future

When developing its clean energy commitment, the Company recognized that the sustainability must be at the center of the plan. Like many of its customers, APS is committed to doing its part to protect the environment and resources for future generations. The focus is to procure the resources that will allow APS to meet its goal to provide 100 % clean energy by 2050 and do it in a manner that continues the Company's record of providing affordable, reliable energy. Using the clean energy commitment as the waypoint, the next few chapters outline the assumptions and how the Company developed the portfolios that are core to its goals.

To Learn More

U.S. Bureau of Reclamation
https://www.usbr.gov/

U.S. Environmental Protection Agency
https://www.epa.gov/

Arizona Department of Water Resources
http://www.azwater.gov/azdwr/

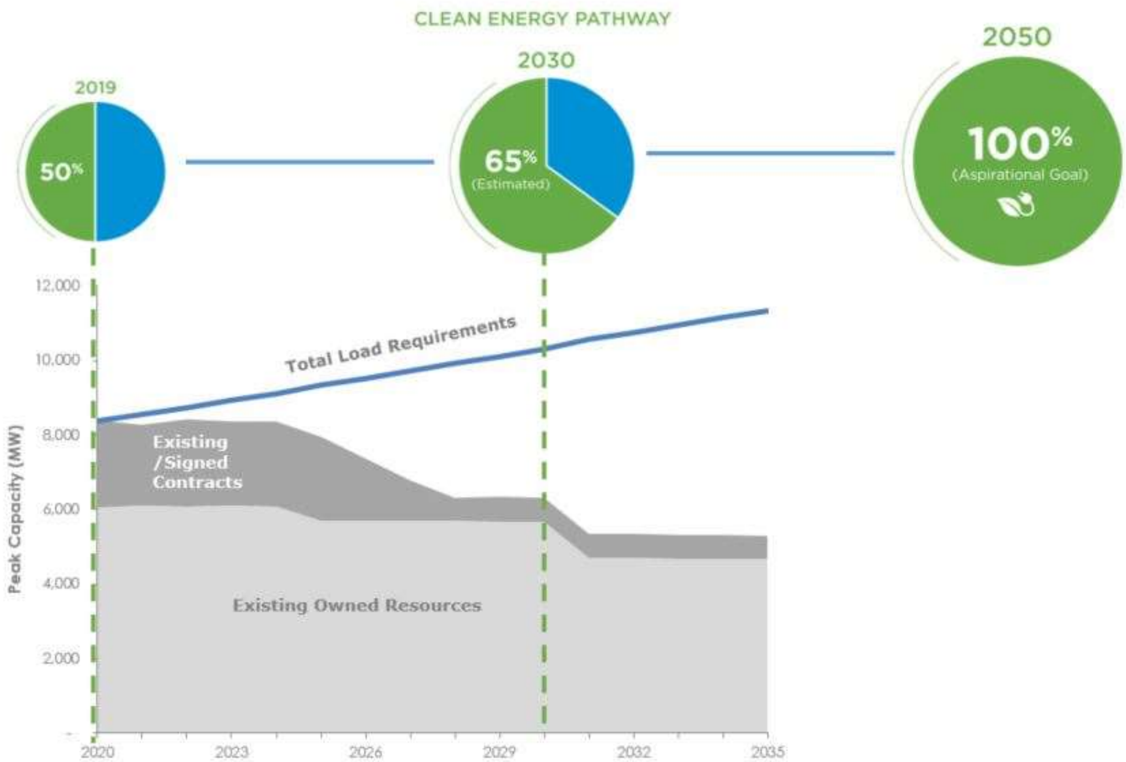
CHAPTER 2

MEETING FUTURE NEEDS

MEETING FUTURE NEEDS

APS will meet its future needs with current and new resources and technologies that fulfill reliability requirements, achieve carbon goals and keep rates affordable for customers. In 2019, APS had reduced its carbon dioxide emissions to 12.3 million metric tons, a 26% decline from 2005 levels. The Company expects to further reduce emissions by another 7-8 million metric tons by 2030 and totally eliminate them by 2050. Even after anticipating additional customer resources of more than 1,600 MW of distributed solar generation and 1,200 MW of energy efficiency (EE) by 2035, APS still expects a reliability need of over 6,000 MW[1] to meet peak load requirements. Approximately half of that need is driven by load growth, and the other half by plant retirements and expiring purchase power contracts. Not only will the peak load requirements need to be met to maintain reliability, but future energy requirements also must be transitioned to zero-emitting carbon resources to meet the ultimate goal of 100% clean, carbon-free electric generation.

FIGURE 2-1. SUPPLY-DEMAND GAP (2020 – 2035)



[1] It is important to note that all resource portfolios will see significantly more additions than 6000 MW due to new resources being paired to meet reliability requirements (i.e., solar with storage requires 100 MW of solar plus 100 MW of storage to provide the reliability equivalent of nearly 100 MW).

Meeting future needs will require APS to ensure it:

- meets its clean energy commitment goals
- maintains customer reliability
- maintains a customer focus
- maintains customer affordability
- maintains the financial health of APS

Elements of the APS clean energy commitment include:

- Counting on Palo Verde as a clean energy cornerstone
- Increasing clean energy resources
- Developing energy storage
- Retiring existing coal plants
- Managing demand with a modern, interactive grid
- Promoting customer technology and energy efficiency
- Utilizing clean regional resources

While clean energy resources and energy storage technologies required to meet the Company's near-term goals are either currently available or expected to be available soon, technology required to meet its long-term goals may not yet exist. This chapter portrays technologies as they are known today or can reasonably expect them to be in the near future, though it is not possible to predict emerging technologies that may be available in the longer term. APS will collaborate with stakeholders including universities, policymakers and potential suppliers to drive development of technologies that will enable the Company to meet its long-term goals. APS is technology neutral and ultimately will choose technologies that best meet customers' energy and reliability needs while maintaining affordability.

EXISTING APS RESOURCES

Palo Verde is the cornerstone of the APS fleet, providing reliable, carbon-free power to millions of customers across the southwest. Additionally, renewable generation on the APS system includes nearly 2,000 MW of Company-owned, contracted and customer resources and over 1,000 MW of DSM products, which all contribute to APS's already 50% clean energy mix. The DSM group of programs also contributes to affordability by giving customers a variety of options to manage their energy usage. Natural gas resources, needed for reliability and to integrate variable solar resources, provide low-cost, low-emitting and flexible capabilities, although in the longer term they will need to transition to lower and zero-carbon emissions. The baseload power provided by the Company's coal-fired generating units will be phased out by 2031. This chapter provides additional details on the current set of APS resources.

FUTURE RESOURCE OPTIONS

New capacity, energy and low-carbon solutions needed to close the supply-demand gap during the Planning Period will come primarily from renewables, energy storage, customer DSM programs, rooftop solar, demand response and microgrids. APS engaged stakeholders and has an open public process as part of the IRP to better understand how to better meet the needs of its customers. The Company is working with stakeholders and consultants to balance industrywide knowledge with the unique energy usage patterns witnessed in the Desert Southwest. Further, APS will continue to work with industry groups and is in regular contact with developers in the utility industry. This allows the

Company to continuously evaluate new resources, technology and ideas that will be required to meet its clean energy goals.

Generation Resources – In assessing generation resource options for the Planning Period, APS considered grid-scale solar, rooftop solar and wind renewable energy resources, energy storage and natural gas. Longer term solutions will consider new and emerging technologies, such as small modular nuclear, advanced forms of long-duration energy storage, hydrogen and carbon capture and sequestration (CCS), among others.

DSM Programs & Initiatives – Regarding customer-based options, APS considered DSM programs ranging from those in current use to emerging concepts aimed at providing load shifting and integration with advanced grid technologies.

PLANNING STUDIES[2]

With the magnitude of change in projected system operations going from the Company's existing resource base towards meeting its clean energy commitment, it was appropriate to re-evaluate some key planning inputs affecting the composition of future resource plans.

DSM Opportunity Study - APS conducted a DSM Opportunity Study in 2019 that was closely coordinated with DSM stakeholders, in order to provide updated information on the technical, economic and achievable potential from a number of traditional and emerging energy efficiency technologies and program opportunities. From this study, APS identified multiple new energy efficiency (EE) opportunities for non-residential customers that were proposed in the 2020 DSM Plan, including efficiency measures targeting the increasing load from computer server facilities (data centers) that are expanding in APS territory. This study is currently being enhanced with a second phase of stakeholder participation and is looking at flexible distributed capacity opportunities from DSM, including a focus on load shifting, demand response, storage and beneficial electrification potential. APS is using the data collected from these studies in conjunction with information from current and historic DSM program activities to develop more granular DSM planning tools to support future load forecasting and integrated resource planning needs. The study is summarized below and included in Appendix A of the IRP.

APS forecasted energy savings and costs for EE opportunities between 2021-2035 to support IRP and DSM planning efforts.

- Scope: 34 new and existing EE technologies across eight customer segments, and two climate zones.
- Methodology: Combined APS DSM planning, load forecasting and resource planning data with market saturation information from 60 subject matter experts to develop estimates of technical, economic and achievable potential and corresponding costs.

APS can achieve from 175 GWh to 200 GWh in cost-effective energy savings at an estimated cost of $37M to $49M annually.

- Residential Sector EE potential primarily consists of:
    - Specialty LEDs, HVAC Quality Installation and Energy Star Homes
- Non-Residential Sector EE potential primarily consists of:
    - Data Center Computer Room AC, Custom Projects and Strategic Energy Management programs
- Other technologies contributing to achievable EE potential include:
    - Smart Thermostats, Linear LEDs, Packaged AC, Home Energy Reports, Limited Income Weatherization, Attic Insulation and Multifamily New Construction

Approximately 60% of technical potential savings pass the economic screen of the ACC Cost Test.

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[2] Additionally, a load forecast review was conducted and reviewed with stakeholders and is described in Chapter 5: Load Forecast.

APS incorporated these opportunities into its 2020 Amended DSM Plan[3]. In addition to the EE potential identified here, APS is currently conducting a second market potential study focused on the following distributed flexible capacity opportunities:

- Demand response
- Energy storage
- Managed EV charging
- Strategic beneficial electrification

Further, the Company has been working with Guidehouse to develop an informed DSM planning tool that will allow it to optimize DSM portfolios to maximize customer benefits and clean attributes.

Electric Vehicle Adoption Forecast and Charging Station Siting Analysis – In 2019, APS retained Navigant Consulting (Guidehouse) to develop a forecast of plug-in electric vehicles (PEVs) in Arizona and in APS's service territory over the next 20 years, and to determine the electric charging infrastructure required to support that level of EV adoption. The study is attached in Appendix B. Navigant used the VAST™ Adoption and VAST™ Charging Forecasting modules to perform the studies. The VAST™ Adoption module is a systems dynamics model that forecasts the penetration of vehicles, by powertrain (battery electric vehicle [BEV], plug-in hybrid electric vehicle [PHEV]), vehicle class, and ownership type (individual/fleet) for plug-in electric vehicles (PEV). It was used to generate geographic outputs for estimated vehicles in operation in the state. The VAST™ Charging Forecasting module estimates the number of chargers needed to meet future demand. The result can be used to estimate load growth, grid impacts, costs and more.

Key inputs to the study included:

- Baseline vehicle registrations and charging infrastructure – from APS
- Historic vehicle sales and vehicle availability
- Gasoline, battery, and component price forecasts – including electricity rates from APS
- State, national, and utility incentives
- Demographic data: Income, educational attainment, units in structure

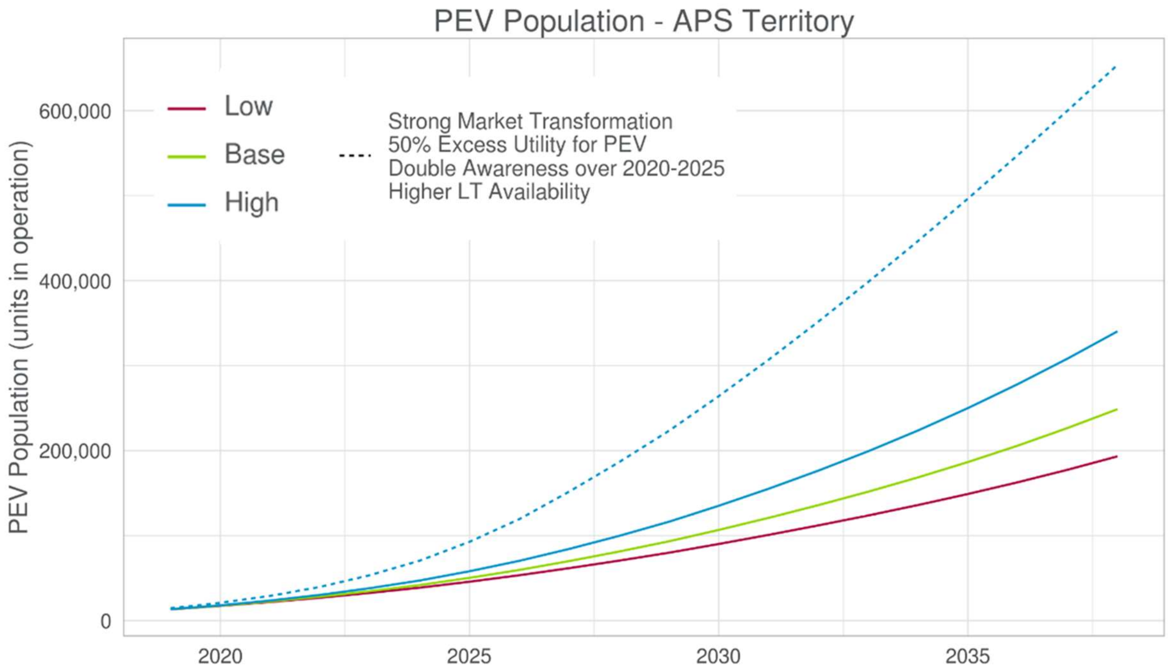
Key outputs of the study were:

- Light-duty vehicle registrations and sales by year, powertrain, and ownership from 2019-2038
- Infrastructure, education/awareness, incentive, eligibility, and utility rate sensitivity scenarios to simulate market and utility interventions
- Estimated number of charging ports by charger type in APS territory

The results included low, base, and high scenarios as well as a Strong Market Transformation Scenario, and are shown in Figure 2-2 below. Navigant estimated the number of light duty plug-in electric vehicles (PEVs) in APS's territory will increase from about 10,000 in 2018 to about 250,000 in 2038 if the current market trajectory persists, under the Base scenario. Under the Market Transformation scenario, the number of PEVs could reach 650,000 by 2038 in APS's territory and 1.5 million statewide if there are significant changes in consumer preference, awareness, and PEV product availability in the near-term. These results were factored into APS load forecast.

[3] Application for approval of APS's Amended 2020 Demand Side Management Implementation Plan, Docket No. E-01345A-19-0088

FIGURE 2-2 – PEV FORECAST IN APS TERRITORY



Integration Cost Study – APS is committed to providing clean energy to its customers and that means planning for the addition of more Variable Energy Resources (VERs) to the system. VERs come with their own unique benefits and challenges – although their fuel is free, their forecasts are not perfect. The potential for weather variation, whether it is unexpected cloud cover that reduces solar generation or a forecasted windy day that does not materialize, does not alleviate APS of its obligation to provide reliable power to its customers at all times. Because of the forecast error associated with variable energy resources, APS asked Energy Exemplar to conduct an integration study to assess the additional costs for integrating both solar and wind resources into APS's generation portfolio.

Energy Exemplar looked at the historical variability of solar and wind resources to develop a view of APS's system in the future. Renewable forecast errors place the system in a position of either generation deficiency or generation surplus on a sub-hourly basis. In order to account for this and maintain resource adequacy, APS must carry operating reserves to either "fill the gap" left by renewables underperforming with respect to its forecast (Regulation Up) or to absorb the additional unexpected energy from the renewable resources (Regulation Down). Energy Exemplar found that there are additional costs associated with both scenarios that are captured in the integration costs, namely increased operating and maintenance costs. Additionally, APS plans to utilize storage resources to aid in the integration of VERs, facilitating cleaner integration while maintaining system flexibility.

The results of the VER integration cost study show that there are additional costs associated with incorporating renewable resources onto the APS system. The costs are resource dependent and are outlined in Table 2-1. APS considers these costs when evaluating renewable resources to ensure affordability and reliability for its customers.

TABLE 2-1: RENEWABLE INTEGRATION COSTS

	2030	2035
Solar Integration Cost ($/MWH)	$ 1.28	$ 1.79
Wind Integration Cost ($/MWH)	$ 2.89	$ 3.11

Reserve Margin Planning – APS typically employs a 15% planning reserve margin in the development of future resource plans based upon a Loss of Load Probability of one event in ten years. With the evolving nature and economics of limited use resources or resources that only produce energy for a fixed amount of time (i.e., solar and energy storage), the Company is currently reviewing additional methods to ensure the reliability of its system. As a result, APS evaluated a similar metric to assess its reserve margin for the current resource plan, Loss of Load Hours (LOLH). LOLH measures the quantity of hours that are not able to be served with existing resources over a given period of time. APS used an estimate of 24 hours over a ten-year period as a basis for its analysis; however, the Company will continue to update and evaluate both the modeling and assumptions on a going-forward basis.

APS utilized the AURORA Production Cost Model's Risk Analysis Functionality to conduct this study. Uncertainty was introduced into the modelling with various load, solar and wind shape sensitivities driven by historical system volatility. The model also simulated different random unit forced outage patterns for each iteration. Numerous model simulations were run and resulted in the necessary reliability data to calculate LOLH for each year from 2020 to 2024, those results are extrapolated throughout the 2035 planning window. Results of the Reserve Margin Study conclude that a 15% reserve margin is sufficient to meet the Company's reliability requirements. However, as the system evolves and new resources are introduced, APS will continue to evaluate and update its approach.

Natural Gas – Natural gas generation has been, and for some time into the future will continue to be, a critical part of delivering reliable and affordable energy to customers. Natural gas generation is a "bridge" resource that will allow APS to manage the transition to a clean energy future while maintaining reliability and affordability. As an important resource for APS and its customers, and due to the changing supply and demand picture of natural gas and the fully subscribed nature of certain pipelines running through Arizona, APS asked Concentric Energy Advisors to perform an assessment of the natural gas outlook.

Concentric assessed the following:

- Natural gas demand in the Desert Southwest and California, and trends
- Natural gas supply and pricing from the Permian Basin
- Natural gas reliability, including contracts on existing pipes, storage landscape, rate impacts of new capacity and pipeline flexibility
- Impact of market changes on APS natural gas portfolio, including pipeline capacity and intraday pipeline flexibility

Key takeaways of the assessment were:

Natural Gas Demand

- Natural gas demand in Arizona and New Mexico are expected to remain strong in short-term driven by electric generation
- Demand is expected to decline over time in California and New Mexico due to meeting RPS goals and scalability of battery storage

Natural Gas Supply

- Permian natural gas prices are currently below market due to pipeline constraints
- However, abundance of supply is expected to keep Permian natural gas prices moderate for the long-term

Natural Gas Reliability

- Weather: Freeze-offs, not hurricanes, are an event to consider for reliability of Southwest gas markets
- Pipeline Rupture: APS's risk related to reliance on natural gas is not seen as materially different than certain other areas in the United States that are more reliant on gas-fired generation
- There is a need to weigh the probability of reliability events against the timing and cost of mitigation

Impacts of Market Changes

- The service quality, reliability, flexibility and rates of APS's existing pipeline contracts would not be affected if existing pipelines require expansion
- APS is only subject to cost increase of an expansion if it contracts for additional capacity that requires an expansion
- Any additional future flexibility would require contracting for additional capacity that may or may not require a pipeline expansion

Natural Gas Storage – Natural gas storage in Arizona has been a matter of discussion for several years. The benefits offered by natural gas storage are local redundancy of fuel should a pipeline disruption occur. Kinder Morgan (KM) has proposed building a natural gas storage facility near Eloy, Arizona to help meet those needs. The Arizona Gas Storage (AGS) project has been offered by El Paso Natural Gas (EPNG) on behalf of KM through an open season notice issued in 2017.

The AGS project offers Arizona a sizeable gas storage solution. AGS, as proposed, could build a salt dome storage facility with a minimum of four caverns and offering at least 4 Bcf of working gas. Salt dome gas storage facilities offer the highest deliverability and cycling of any geological gas storage facility. Due to a lack of interest and increasing alternative storage options (including batteries), the project has been delayed indefinitely, and no other natural gas storage projects are currently being offered. APS will continue to monitor developments in this area and consider if or how natural gas storage fits into the Company's resource strategies.

Existing APS Resources

The map in FIGURE 2-3. **APS RESOURCE MAP**-3 details the location of APS's existing resource mix, with the exception of small-scale solar projects, customer-side resources such as EE, rooftop solar and demand response and conventional purchased power contracts. These resources are existing as of 2020.

FIGURE 2-3. APS RESOURCE MAP

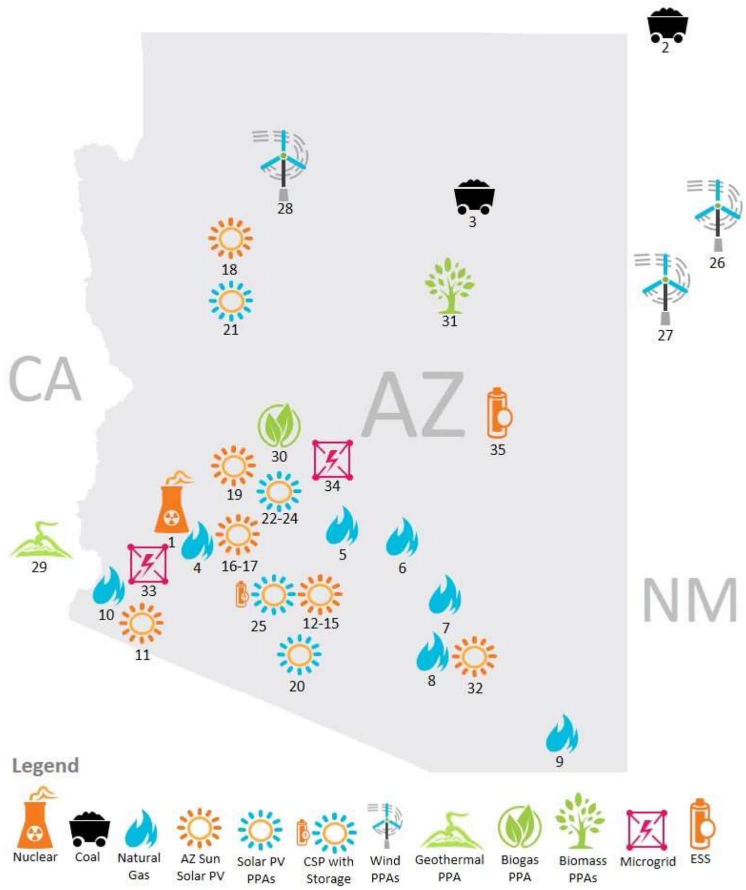


TABLE 2-2. APS EXISTING RESOURCES

By Resource	
Total Resources	**10,773 MW**
Nuclear	1,146 MW
Coal	1,357 MW
Natural Gas	5,233 MW
Owned Resources	3,573 MW
PPAs	1,660 MW
Microgrid	32 MW
ESS	2 MW
Renewables	883 MW
Solar	567 MW
Owned Resources	242 MW
PPAs	325 MW
Wind (PPAs)	289 MW
Other (PPAs)	27 MW
Customer-Based	2,120 MW
Energy Efficiency	1,038 MW
Distributed Energy	1,044 MW
Demand Response	38 MW

TABLE 2- 3. APS RESOURCE MAP NUMBER GUIDE

Map #	Plant	APS MW	In Service	Map #	Plant	APS MW	In Service
1	Palo Verde	1,146	1986-88	**19**	Luke AFB	10	2015
2	Four Corners	970	1969-70	**20**	Ajo Project	5	2011
3	Cholla	387	1962-80	**21**	Prescott Project	10	2011
4	Redhawk	1,088	2002	**22**	Saddle Mountain	15	2012
5	West Phoenix	997	1972-2003	**23**	Badger 1 Solar	15	2013
6	Ocotillo	620	1960-1970	**24**	Gillespie	15	2013
7	Sundance	420	2002	**25**	Solana	250	2013
8	Saguaro	189	1972-2002	**26**	Aragonne	90	2006
9	Douglas	16	1972	**27**	High Lonesome	100	2009
10	Yucca	243	1971-2008	**28**	Perrin Ranch	99	2012
11	Foothills	35	2013	**29**	Salton Sea	10	2006
12	Paloma	17	2011	**30**	NW Regional	3	2012
13	Cotton Center	17	2011	**31**	Snowflake	14	2008
14	Gila Bend	32	2014	**32**	Red Rock	40	2016
15	Desert Star	10	2015	**33**	MCAS Yuma	22	2016
16	Hyder	16	2011	**34**	Aligned Microgrid	11	2017
17	Hyder II	14	2013	**35**	Punkin Center	2	2018
18	Chino Valley	19	2012				

Existing Nuclear

POWER PLANT (APS MW Entitlement) - Total: 1,146 MW

PALO VERDE NUCLEAR GENERATING STATION (1,146 MW)

Palo Verde is a three-unit nuclear power plant located 50 miles west of Phoenix. APS operates the plant and owns 29.1% of Palo Verde Units 1 and 3 and has a combined ownership/leasehold interest of 29.1% in Unit 2. The NRC issued renewed operating licenses for each of the three units in April 2011, which extended the licenses for Units 1, 2 and 3 to June 2045, April 2046 and November 2047, respectively.

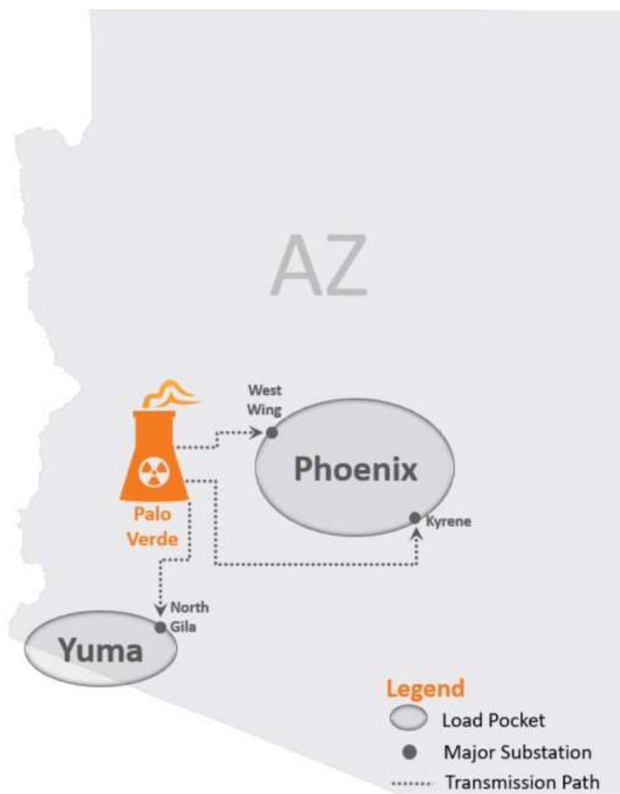
Palo Verde is the nation's largest power producer of any kind. In 2019, Palo Verde produced 31.9 million MWh of carbon-free energy – the only U.S. generating facility to produce more than 30 million MWh in a single year.

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. Through those agreements, APS retains the assets through 2023 under one lease and 2033 under two other leases. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years or return the assets to the lessors.

Other Plant Highlights:

- Total plant operating capacity: over 4,000 MW (APS's share: 1,146 MW)
- Commercial operation of Units 1 and 2 began in 1986 and Unit 3 in 1988
- Provides electricity to four million people in Arizona, California, New Mexico and Texas
- Only nuclear plant in the world not located near a large body of water
- Only nuclear power plant in the world that uses reclaimed municipal wastewater as its cooling water. On average, Palo Verde recycles 20 billion gallons of wastewater per year
- Has a $2.1 billion annual economic impact and is the largest single commercial taxpayer in Arizona
- Major trading hub in the West

FIGURE 2-4. HOW PALO VERDE MEETS CUSTOMER DEMAND



Existing Coal

POWER PLANTS (APS MW Entitlement at Beginning of Planning Period) - Total: 1,357 MW

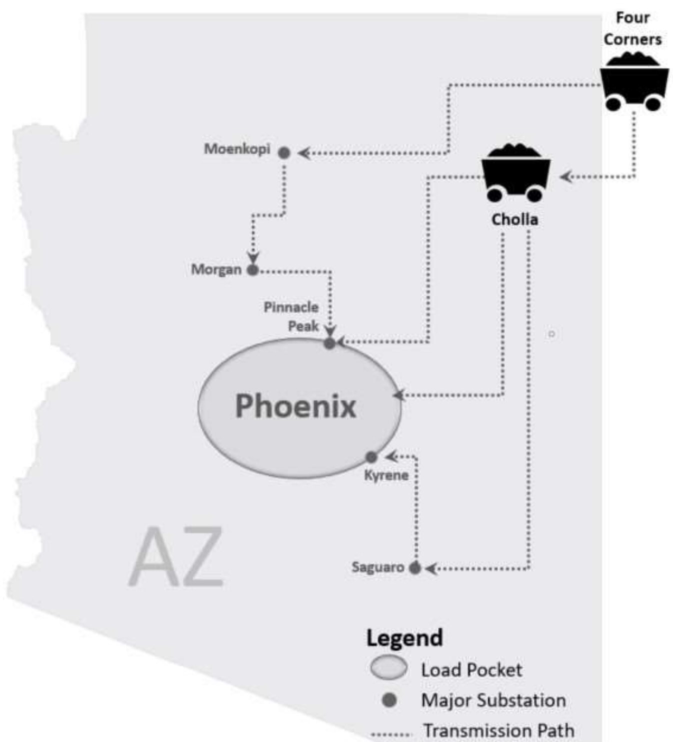
FOUR CORNERS POWER PLANT (970 MW)

Four Corners Power Plant is composed of two 770 MW units located near Farmington in the northwest corner of New Mexico. APS operates and owns 63% of the plant. Currently, operation of Units 4 and 5 have a large economic impact on the region that benefit the Navajo Nation and local citizens significantly. It has delivered reliable power to APS customers and the Southwest for more than 50 years, however, in order to fulfill the Company's clean energy commitment, the plant will cease operation by 2031. The Company will work with employees and affected communities to ease the transition from coal and help with their long-term economic planning. APS strives to be open and transparent, and is providing as long a lead time as possible to reduce the impact of job losses and lower tax revenue.

CHOLLA POWER PLANT (387 MW)

Cholla, originally a four-unit coal-fired power plant, is located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1 and 3. PacifiCorp owns the 380 MW Unit 4, the plant's largest unit, and plans to retire it by the end of 2020. Unit 2 was closed on October 1, 2015 as part of an environmental agreement with the United States Environmental Protection Agency (EPA). Units 1 and 3 are projected to stop burning coal no later than 2025 as part of the same agreement.

FIGURE 2-5. HOW EXISTING COAL RESOURCES MEET CUSTOMER DEMAND



Existing Natural Gas

POWER PLANTS (APS MW Entitlement at Beginning of Planning Period) Total: 3,573 MW

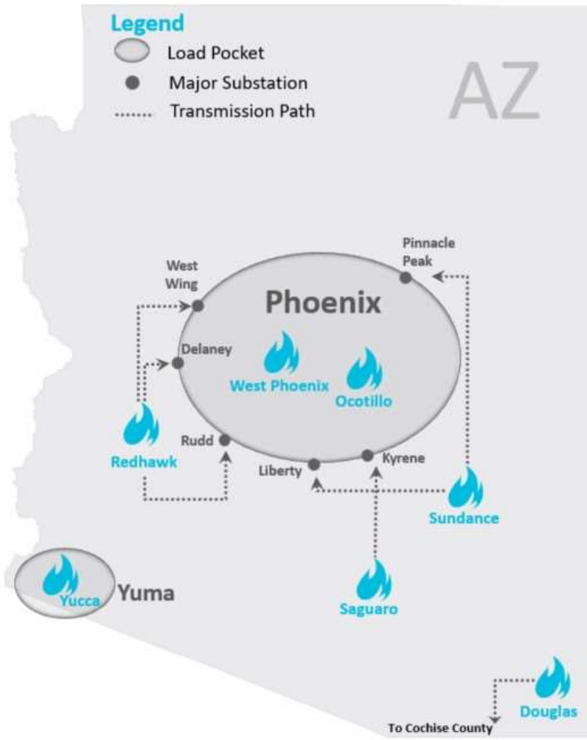
REDHAWK POWER STATION (1,088 MW)

Redhawk Power Station, which began operating in mid-2002, consists of two identical approximately 500 MW natural gas-fueled combined-cycle units. Located west of Phoenix, the station utilizes treated effluent purchased from Palo Verde to meet its cooling needs. Redhawk also is a zero liquid discharge site, meaning that the cooling water is continually reclaimed and reused. The plant is owned and operated by APS.

WEST PHOENIX POWER PLANT (997 MW)

West Phoenix Power Plant, located in southwest Phoenix, has seven natural gas-fueled generating units – two combustion turbine units and five units that employ combined-cycle technology. The plant is owned and operated by APS.

FIGURE 2-6. HOW EXISTING NATURAL GAS RESOURCES MEET CUSTOMER DEMAND



OCOTILLO POWER PLANT (620 MW)

Ocotillo Power Plant in Tempe is a seven-unit gas plant. In 2019, APS completed modernization of the plant, which involved retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increased the capacity of the site by 290 MW, to 620 MW. The plant is owned and operated by APS.

The completed Ocotillo project supports service reliability and renewable integration in the Phoenix metro area, improves the plant's appearance, benefits the environment and adds additional tax revenue to the local economy.

SAGUARO POWER PLANT (189 MW)

Saguaro Power Plant, a natural gas-fueled facility located north of Tucson, includes three combustion turbine units. The plant is owned and operated by APS.

SUNDANCE GENERATING STATION (420 MW)

Sundance Generating Station in Coolidge is a natural gas-fueled combustion turbine plant that consists of ten quick-start units. The plant is owned and operated by APS.

SAGUARO POWER PLANT (189 MW)

Saguaro Power Plant, a natural gas-fueled facility located north of Tucson, includes three combustion turbine units. The plant is owned and operated by APS.

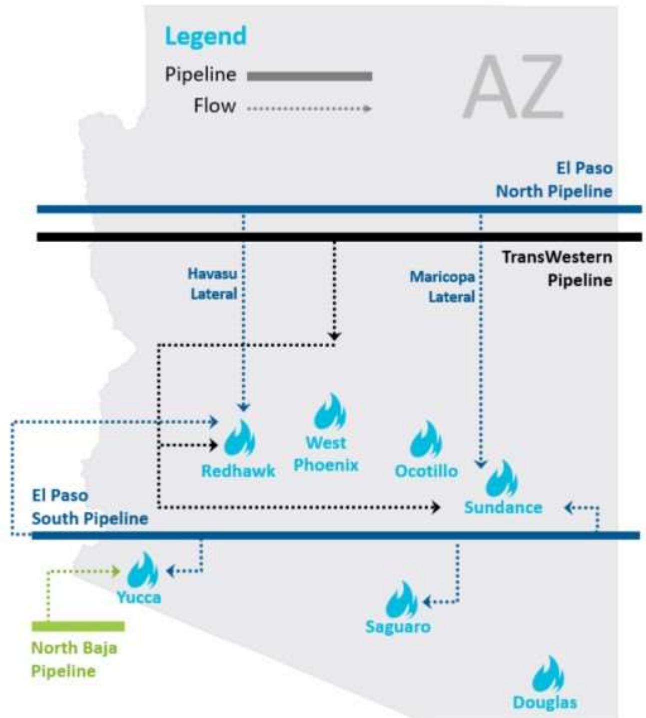
DOUGLAS POWER PLANT (16 MW)

Douglas Power Plant, located in Douglas in southeastern Arizona, has one 15 MW combustion turbine peaking unit and is put into service only when demand for electricity is high in the Douglas area. The plant is owned and operated by APS.

YUCCA POWER PLANT (243 MW)

Yucca Power Plant, a natural gas-fueled plant near Yuma, has six combustion turbine units that produce 233 MW owned and operated by APS, and one 75 MW steam turbine and one 22 MW combustion turbine that are owned by Imperial Irrigation District and operated by APS.

FIGURE 2-7. NATURAL GAS PIPELINE MAP



NATURAL GAS PURCHASE POWER AGREEMENTS

TOTAL NATURAL GAS PURCHASED POWER AGREEMENTS 1,660 MW

APS currently has 1,660 MW of natural gas-based Purchase Power Agreements (PPAs) in place and another one (463 MW) contracted to begin in 2021. Current PPAs include a seasonal exchange (480 MW), two merchant combined cycle tolling agreements (1,135 MW) and a small contract (45 MW). All of these PPAs will expire by the end of 2027.

Existing Grid-Scale Renewable Energy

TOTAL GRID-SCALE RENEWABLE ENERGY (APS MW Entitlement at Beginning of Planning Period) 883 MW

SOLAR - Total: 567 MW

PALOMA SOLAR POWER PLANT (17 MW)

Paloma Solar Power Plant is a photovoltaic facility located in Gila Bend. The plant began serving customers in the third quarter of 2011, and is comprised of 280,000 thin-film fixed tilt modules. The plant is owned and operated by APS.

COTTON CENTER SOLAR PLANT (17 MW)

Cotton Center Solar Plant is a photovoltaic facility also located in Gila Bend. The plant began serving customers in the third quarter of 2011 with about 93,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

HYDER SOLAR POWER PLANT (16 MW)

Hyder Solar Power Plant is a photovoltaic facility located in Hyder. The plant began serving customers in the fourth quarter of 2011 with about 70,000 multicrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

HYDER II SOLAR POWER PLANT (14 MW)

Hyder II Solar Power Plant is a photovoltaic facility located in Hyder. The plant began serving customers in the fourth quarter of 2013 with more than 71,000 multicrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

CHINO VALLEY SOLAR PLANT (19 MW)

Chino Valley Solar Plant is a photovoltaic facility located in Chino Valley near Prescott. The plant began serving customers in the fourth quarter of 2012 with about 77,000 multicrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

FOOTHILLS SOLAR PLANT (35 MW)

Foothills Solar Plant is a photovoltaic facility located near Yuma. Construction of the plant was completed in the fourth quarter of 2013. The plant is composed of more than 182,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

GILA BEND SOLAR PLANT (32 MW)

Gila Bend Solar Plant, a photovoltaic facility located near Gila Bend, became fully operational in October 2014. Built on 400 acres, the plant includes about 172,000 polycrystalline modules on a single-axis tracking system. The plant is owned and operated by APS.

LUKE AIR FORCE BASE (AFB) SOLAR PLANT (10 MW)

Luke AFB Solar Plant is a 10 MW photovoltaic facility located on Luke AFB in Glendale, about 18 miles northwest of downtown Phoenix. Owned and operated by APS, the facility has 50,800 multicrystalline modules and became operational in the summer of 2015.

DESERT STAR SOLAR PLANT (10 MW)

Located on 100 acres in Buckeye, Desert Star became fully operational in June 2015. The plant, owned and operated by APS, has 50,800 multicrystalline modules on a single-axis tracking system.

AJO PROJECT (5 MW)

Ajo Project, a crystalline photovoltaic single-axis tracking system, is located near Ajo and reached commercial operation in September 2011. APS has a 25-year purchased power agreement for the entire project output.

PRESCOTT PROJECT (10 MW)

Prescott Project, located two miles north of Prescott Regional Airport, is a crystalline photovoltaic single-axis tracking system. APS purchases the generation output under a 30-year agreement, which began in November 2011.

SADDLE MOUNTAIN PROJECT (15 MW)

Saddle Mountain Project is a crystalline photovoltaic single-axis tracking system located near Tonopah. APS purchases the generation under a 30-year agreement, which began in December 2012.

BADGER 1 SOLAR FACILITY (15 MW)

Badger I Solar Facility, a crystalline photovoltaic single-axis tracking system located near Tonopah, reached commercial operation in November 2013. APS has a 30-year purchased power agreement for the entire output.

GILLESPIE (15 MW)

Gillespie, located near Arlington, is a crystalline photovoltaic single-axis tracking system. APS purchases the generation output from Recurrent Energy under a 30-year agreement, which began in December 2013.

SOLANA GENERATING STATION (250 MW)

Solana, located near Gila Bend, uses concentrated solar power (CSP) technology with a thermal energy storage system. APS purchases the generation output from Arizona Solar One (Abengoa) under a 30-year agreement, which began in October 2013.

RED ROCK (40 MW)

Red Rock is a 40 MW photovoltaic facility located in southern Pinal County. It includes 182,880 multi-crystalline modules. The facility is an APS collaboration with PayPal and Arizona State University – two commercial customers that purchase the equivalent of 100% of the facility's energy output from APS. The plant is owned and operated by APS.

SCHOOLS & GOVERNMENT* (12 MW)

The solar installations for Schools & Government are fixed solar photovoltaic systems installed throughout Arizona. The program consists of 59 school installations which APS owns and operates.

LEGACY* (4 MW)

Legacy solar photovoltaic systems installed throughout Arizona are a mix of fixed and single-axis tracking systems. The fleet is comprised of 36 systems, representing the oldest of the APS-owned and operated solar facilities.

APS SOLAR PARTNER PROGRAM / FLAGSTAFF COMMUNITY PROJECT / SOLAR COMMUNITIES PROGRAM* (16 MW)

These projects include more than 2,100 rooftop solar systems installed on homes and completed by the end of 2019 in the Phoenix area, and 125 completed by the end of 2012 in Flagstaff. The solar photovoltaic systems are owned and operated by APS.

BAGDAD* (15 MW)

Bagdad is 15 MW crystalline photovoltaic single-axis tracking facility located in Yavapai County. A third party contract with APS to buy back the entire output under a 25-year agreement that began in December 2011.

*Diverse small-scale solar projects and grid-scale distributed resources are not shown on the APS Resource Map.

WIND - Total: 289 MW

ARAGONNE MESA WIND PROJECT (90 MW)

Aragonne Mesa Wind Project, located in New Mexico, delivers its capacity to APS at the Four Corners switchyard. APS has a 20-year PPA to purchase the entire project output. It began making energy deliveries to APS in December 2006.

HIGH LONESOME WIND PROJECT (100 MW)

High Lonesome Wind Project, located in New Mexico, delivers its capacity to APS at the Four Corners switchyard. APS has a 30-year PPA to purchase the entire project output. It began making energy deliveries to APS in 2009.

PERRIN RANCH WIND PROJECT (99 MW)

Perrin Ranch Wind Project, located near Williams, reached commercial operation in June 2012. APS has 25-year PPA to purchase the entire project output.

OTHER RENEWABLE ENERGY - Total: 27 MW

SALTON SEA GEOTHERMAL PROJECT (10 MW)

Salton Sea Geothermal Project, located in the Salton Sea area of southeastern California, delivers capacity to the APS system in Yuma. APS has a 23-year PPA to purchase its output. The project began delivering energy to APS in January 2006.

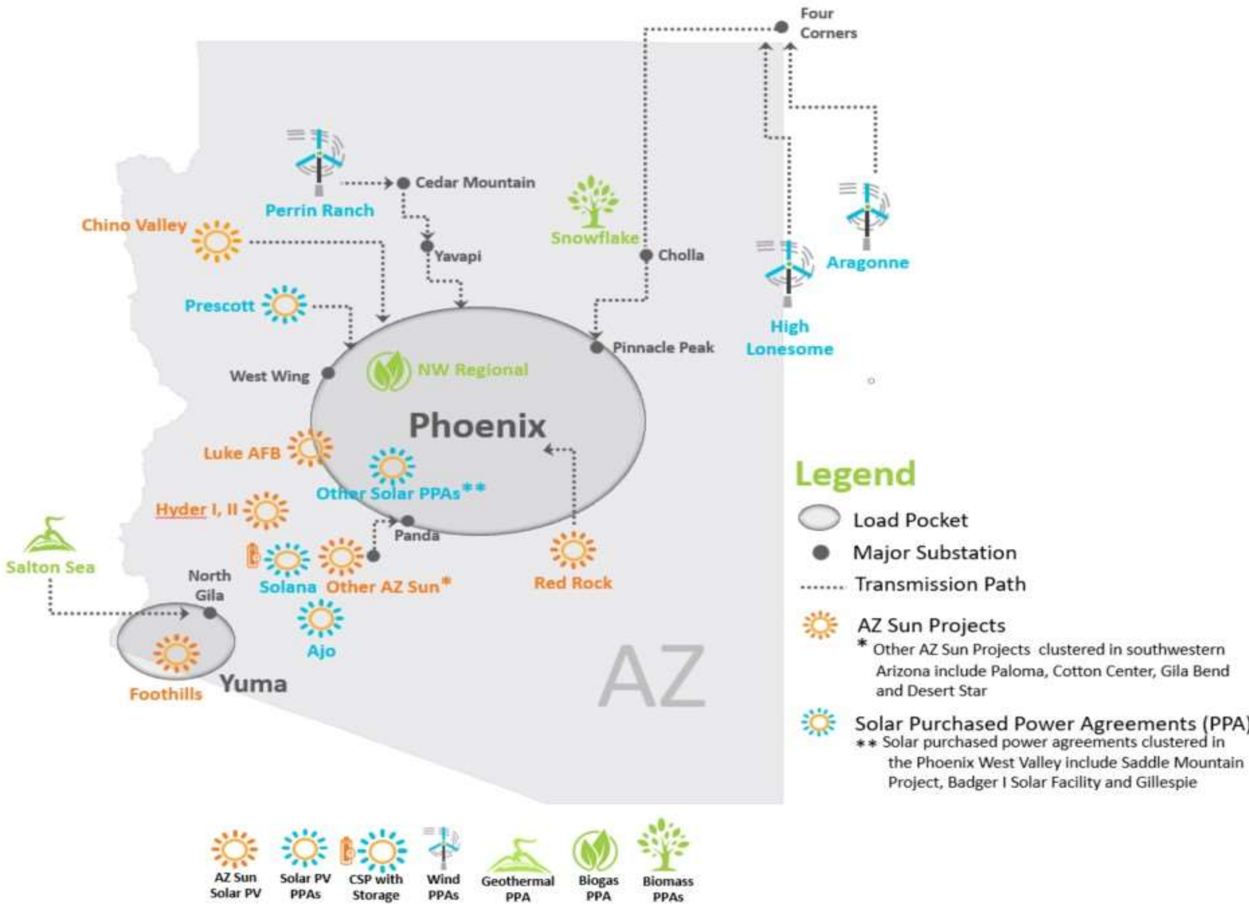
NORTHWEST REGIONAL BIOGAS PROJECT (3 MW)

Northwest Regional Biogas Project, located in Surprise, commenced operations in August 2012 and sells all its energy to APS under a 20-year PPA.

SNOWFLAKE BIOMASS PROJECT (14 MW)

Snowflake Biomass Project commenced commercial operations in June 2008 and sells part of its output to APS under a 15-year PPA.

FIGURE 2-8. HOW EXISTING RENEWABLE RESOURCES MEET CUSTOMER DEMAND



Existing Microgrid Resources

MICROGRID (APS MW Entitlement) - Total: 32 MW

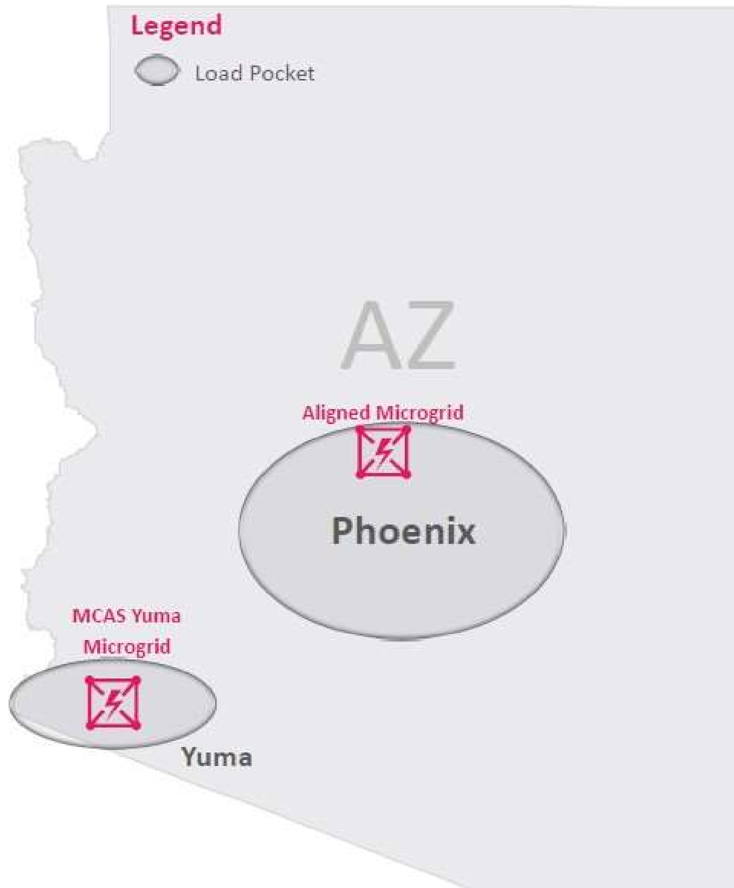
MARINE CORPS AIR STATION (MCAS) YUMA MICROGRID (22 MW)

The MCAS Yuma project provides the base 100% backup power in the event of a grid disruption and fast-starting, clean-burning diesel generation set (genset) power to the rest of the community under normal operating conditions. The benefits of the project also extend to adding needed flexible capacity to the system while delivering a customized solution to a key client.

ALIGNED MICROGRID (11 MW)

The Aligned Microgrid is a ground-up, purpose-built system designed specifically for the load profile associated with the Aligned Data Center and the surrounding community. The microgrid integrates underground 69KV power supply with multi-redundancy and leading-edge reliability designed into all systems and subsystems.

FIGURE 2-9. HOW THE MICROGRIDS MEET CUSTOMER DEMAND



Existing Customer-Based Resources

CUSTOMER-BASED-RESOURCES – Total: 2,137 MW

ENERGY-EFFICIENCY (1,038 MW)

APS expects to achieve cumulative energy savings of 22% of its retail sales by 2020. APS's EE portfolio includes a balanced mix of programs that address APS's diverse customer base in both residential and non-residential categories. These programs include, but are not limited to, the following:

- Residential Existing Homes – promotes energy efficiency in existing homes with Heating, Ventilation and Air Conditioning (HVAC) and Home Performance program elements that support energy-efficient residential air conditioning and heating including smart thermostats, HVAC system quality installation, home air sealing, insulation and duct repair.
- Residential New Construction program promotes high-efficiency construction practices for new homes.
- Large Existing Facilities program provides incentives to non-residential facilities for EE improvements in HVAC, motors, controls and custom energy saving projects.
- Non-Residential New Construction and Major Renovations program promotes an integrated and comprehensive approach to improve the efficiency of new non-residential construction facilities through improvements in building design, construction and energy efficient systems.
- Schools program provides assistance in reducing energy used in schools, including public, private and charter schools (K-12), through upgrades to lighting, refrigeration, HVAC and other end uses.

DEMAND RESPONSE (55 MW)

APS's demand response programs include:

- APS Peak Solutions is a 25 MW commercial and industrial DR program for APS's Yuma and Phoenix metropolitan customers.
- Peak Event Pricing (or Critical Peak Pricing) for residential and business customers is a rate rider that provides a high price signal over a small number of core summer peak days and hours.
- The APS Rewards program is an award-winning Distributed Energy Resources (DER) pilot project that provides flexible distributed capacity through an aggregation platform that connects to customer DERs. The pilot includes the Cool Rewards smart thermostat demand response program, which controls more than 20,000 participating smart thermostats to reduce peak demand for up to 20 summer days during two- to three-hour peak demand events. The pilot also includes more than 200 connected heat pump water heaters and more than 40 connected battery storage systems. In total, the pilot is expected to provide 30 MWs of peak capacity in summer 2020.

ROOFTOP-SOLAR (1,044 MW)

The Renewable Energy Standard (RES) requires that APS satisfy a percentage of the annual renewable energy requirement through the addition of distributed energy (DE) resources. The required DE percentage is 30%.

DE resources include rooftop/customer-sited rooftop solar PV systems that convert the sun's energy into electricity. As of year-end 2019, APS had more than 103,000 customer-owned/leased distributed PV systems, 125 APS-owned distributed PV systems on residential customer premises as part of the Flagstaff Community Power Project, 1,490 APS-owned distributed PV systems on residential customer premises as part of the APS Solar Partner program, 614 APS-owned distributed PV systems on residential and commercial premises as part of the APS Solar Communities program, and 59 APS-owned distributed PV systems on commercial and industrial premises as part of the APS Schools and Government program.

Future Resource Options

APS ASSESSMENT OF FUTURE RESOURCE OPTIONS

With APS's clean energy commitment, the Company is exploring all options that can propel it to a low-carbon future in the near term, and to be carbon-free in the long term. The Company acknowledges that the technologies needed to get there may not exist today. Reliability and affordability are minimum requirements. The 2020 IRP incorporates that view in selecting technologies for review that will ensure APS meets its commitment to reliable, reasonably priced and sustainable service for the future. Factors considered in the assessment of future resource options include:

Resource Resilience

The evaluation of future resource options, some in early phases of development, includes assessing the potential contribution of those resources to enterprise agility – meaning the ability of a company to adapt to changing operating conditions over time. Renewable and energy storage technologies are expected to play a prominent role in driving to the 2030 goals. These resources will need to be integrated in a way that maintains reliability and affordability that customers have come to expect. Natural gas resources will also be key for providing stable, low-priced energy, and will also enable the integration of variable resources and supporting advanced grid capabilities that require quicker response times. As newer technologies are become commercially viable and economical, the use of natural gas will be phased out, replaced with hydrogen fuel, or employ carbon capture and sequestration technology.

Technological Due Diligence

The technological due diligence process considers several factors, including (a) resource reliability – the ability to reliably produce energy for APS customers when they most need it; (b) technological maturity – sufficient confidence that the addition of a new resource type will not subject APS customers to costs on timing uncertainty, difficulties in graduating from test-scale to grid-scale, shortfalls in operational capabilities under a full range of conditions and limited integration capability with resources already in place; (c) while maturity is essential to certain long-term decisions, APS will also explore flexibility in small scale evaluations of new technologies to promote new resources and evaluate new ideas in the march to carbon-free electricity; and (d) environmental impact – the commitment to limit the impact of a resource on carbon emissions, Arizona's water levels, noise levels, land use, soil quality and local habitat.

As the Company incorporates lessons learned from the 2019 battery failure at McMicken, operation and installation of battery storage facilities on APS's system have been paused temporarily. Once those lessons learned can be incorporated into requirements for all battery installations on the APS system to ensure safety and reliability, the Company will move forward on the use of batteries to support APS customer needs.

Cost

At a time when investments in infrastructure upgrades and new technologies are key objectives, maintaining affordable cost of service to customers through the Company's planning and other processes is paramount. A key consideration in the assessment of new technologies is not only their cost outlooks, but also the reliability of those cost outlooks given the lack of track record in large-scale, operational settings. To ensure APS continues to deliver reasonably priced power as it expands its resource mix over the Planning Period and beyond, the Company's commitment to a comprehensive and proactive stance on cost issues remains. The most recent examples include APS's RFPs for energy storage technologies, solar and wind resources.

Customer Resources

Solar: Rooftop

OVERVIEW AND RISK CONSIDERATIONS

Residential and commercial solar continue to show robust additions in Arizona. BNEF projects that U.S. installed commercial and industrial PV capacity will increase by approximately 13 GW between 2020 and 2025, while residential capacity will increase approximately 27 GW during the same time frame.

Integration of rooftop solar has provided some challenges because APS currently has no control over the output, which has led directly to operational issues on the distribution system and contributed to over-generation issues on the bulk power system. Moving forward, the development, adoption and management of other distributed energy resource technologies such as electric vehicles, battery storage, smart thermostats and advanced solar inverters will be necessary to better integrate the large amount of rooftop solar interconnected on the APS grid. In addition, APS is developing a Distributed Energy Resource Management System to coordinate and occasionally control the thousands of rooftop solar systems and distributed energy resource devices on its system.

DSM Programs and Initiatives

CURRENT DSM PROGRAMS

DSM programs that are currently being implemented

1. Existing Homes Program (includes HVAC, Home Performance and Consumer Products)
2. Residential New Construction
3. Multi-Family EE
4. Limited Income Weatherization
5. Home Energy Reports
6. Non-Residential Existing Facilities (includes Small Business)
7. Non-Residential New Construction
8. Schools
9. Energy Information Service
10. Codes and Standards
11. APS System Savings
12. Demand Response
13. Energy and Demand Education

NEW DSM PROGRAMS

Recently proposed DSM programs and pilots

1. Beneficial Electrification Pilot
2. Electric Vehicle Load Management Pilot
3. New Home Connected Community Research Project
4. Demand Response, Energy Storage and Load Management Initiative (currently being implemented)

DSM PROGRAMS IN DEVELOPMENT

DSM technologies and trends currently being assessed

1. Connected Devices
2. Load Monitoring and Management
3. Load Shifting
4. Energy Storage
5. Automated Demand Response
6. Reverse Demand Response

Current DSM Programs

APS's current portfolio of DSM programs provides opportunities for customers to save energy, reduce peak demand and shift their energy use to off-peak hours within a wide range of customer segments and energy end uses. APS is on target to exceed the cumulative DSM savings goal of 22% of expected annual retail energy sales by the end of 2020.

While DSM provides a valuable resource, it also requires different perspectives in terms of resource planning. Energy efficiency measures typically require customers to make an upfront investment in exchange for savings that occur over the lifetime of the product. Because that investment decision is made by customers, there is uncertainty regarding the amount of energy efficiency that will be implemented. And once energy efficiency is implemented, it may not always perform as expected or be available during times of system peak demand, because most current DSM measures are not utility controlled or dispatched resources. This is starting to change with the emergence of more cloud-connected appliances and devices, which APS is utilizing in the award-winning Rewards distributed energy resource program that works with customers to dispatch smart thermostats, water heaters and battery storage systems. Similar to energy efficiency, demand response initiatives are contingent upon customer participation. Factors such as comfort impact, upfront cost and usability of technology, load reduction (kW) per household and incentives for participation will influence the ultimate impact of such programs.

Another unique challenge is that energy efficiency measures reduce revenue necessary to recover

APS's fixed costs. From a resource parity perspective, a reasonable performance incentive or other financial mechanism is required for energy efficiency to be pursued on financial par with supply-side resources where shareholders receive a rate of return for these investments. In its 2012 rate case settlement agreement, APS agreed to a limited Lost Fixed Cost Recovery mechanism that partially recovers some revenues to help cover fixed costs such as billing and services that must still be provided although there is less revenue to support them. In its filed 2018-2020 DSM Implementation Plans, APS has elected to forgo a performance incentive in an effort to evolve the DSM portfolio to better meet the needs of all customers and its system. However, in the future, APS will need a more comprehensive ratemaking mechanism to address the recovery of the fixed cost investments in accordance with provision A.C.C. R14-2-2410 of the Arizona Energy Efficiency Standard (EES), which states, "an affected utility may recover the costs that it incurs in planning, designing, implementing and evaluating a DSM program or DSM measure … including any unrecovered fixed costs and net lost income/revenue resulting from its Commission-approved DSM programs."

APS continuously strives to align DSM programs and energy efficiency resources with its resource needs. During the planning process for each DSM Implementation Plan, APS reviews the cost-effectiveness of all EE programs using updated avoided costs. Currently, avoided costs remain low due to continuing low natural gas prices and increasing amounts of solar energy that have zero marginal fuel cost, making many EE programs less cost-effective. The continued penetration of distributed solar energy is also causing changes to the system load shape (i.e., the "duck curve" shape), which further reduces avoided costs during midday hours, when there is an abundance of solar energy available. This makes avoided costs much more time-dependent, further reducing cost-effectiveness for programs and technologies that save energy during midday. To stay cost-effective and focus program spending on the highest value savings, APS has proposed many changes in its 2018-2020 DSM Plans, which are awaiting ACC review and approval.

In accordance with Decision No. 75679, the DSM portfolio must continually evolve to better align with changing resource needs by focusing programs on reducing peak demand in the late afternoon and early evening, with less focus on programs that provide midday kWh savings, when there is often excess solar energy in the region. DSM programs that focus on increasing energy usage in the middle of the day will help lower customer bills and assist with integrating additional renewables on the APS system. Carefully targeting DSM programs can achieve the best energy savings load profiles and integrate energy efficiency with load shifting and demand response opportunities.

The current APS DSM portfolio includes the following programs and initiatives:

Existing Homes Program includes HVAC, Home Performance and Consumer Products program elements with a combination of financial incentives, contractor training and consumer education to promote efficiency in existing single-family homes. The HVAC element includes customer incentives for installing quality replacement air conditioners, duct test and repair, Western cooling control and smart thermostat measures. These support energy-efficient residential air conditioning and heating systems along with the proper installation, maintenance and repair of these systems. The Home Performance element promotes a whole-house approach to DSM by offering incentives for improvements to the building envelope of existing residential homes in the APS service area, including measures that improve home efficiency and make it better at shifting energy use with air sealing and insulation. The Consumer Products element includes incentives for smart thermostats and education efforts about energy efficient LED lighting and variable-speed pool pumps.

Residential New Construction Program promotes high-efficiency construction practices for new homes by offering incentives to builders that meet the program's efficiency standards, which are aligned with the national EPA/DOE ENERGY STAR Homes Program. The program emphasizes the whole-building approach to improving EE and includes third-party field testing of homes by independent Home Energy Raters to ensure performance.

Limited Income Weatherization Program serves limited-income customers with various home improvement measures, including cooling system repair and replacement, insulation, sunscreens, water heaters, window repairs and improvements, smart thermostats and other household repairs.

Conservation Behavior (Home Energy Reports) Program provides participating residential customers with periodic personalized reports containing information designed to motivate them to adopt energy conservation behaviors, learn about energy saving programs and services available from APS and track their progress over time.

Multifamily Energy Efficiency Program aims to improve the efficiency of multifamily properties and dormitories by using a comprehensive approach designed to target existing and new multifamily buildings, including incentives for high-efficiency new construction projects and free energy savings devices to be installed in residential units.

Existing Facilities Program provides prescriptive incentives to owners and operators of non-residential facilities for efficiency improvements in HVAC, motors, controls, energy management systems and other efficiency measures. Custom incentives are also provided for efficiency measures not covered by the prescriptive incentives. The program includes a small business element for that customer segment to help them take advantage of the program incentives and services.

New Construction and Renovation Program includes three components: 1) design assistance; 2) prescriptive measures; and 3) custom efficiency measures that are targeted to improve the energy efficiency of new large commercial and government buildings.

Schools Program is designed to set aside DSM funding for K-12 school buildings, including public schools, private schools and charter schools. The schools program includes some DSM measures such as lighting and refrigeration that have been suspended in other programs but are still available to help schools.

Energy Information Services Program provides large non-residential customers with interval usage information that can be used to improve or monitor energy usage patterns, reduce energy use, reduce demands during on-peak periods and to better manage their overall energy operations.

Codes and Standards Initiative encourages energy savings by supporting better compliance with energy codes and appliance standards in jurisdictions throughout the APS service area.

APS System Savings Initiative projects include, but are not limited to, APS generation, transmission, distribution and facilities energy efficiency improvements as well as conservation voltage reduction strategies. Currently, the program is focused on conservation voltage reduction on select distribution feeders.

Demand Response Programs include the Peak Solutions non-residential demand control program and residential Critical Peak Pricing rates.

Energy and Demand Education offers a wide range of the energy information tools designed to help educate residential customers, non-residential customers and industry trade allies about opportunities for saving energy and managing peak demand. They include online energy audit tools, virtual and on-site energy assessments, an energy education events team and emerging data analytics tools that provide personalized tips for saving energy based on each customer's unique energy use patterns.

New DSM Programs

While traditional EE programs provide customers a greater role in managing their energy use, the focus of DSM efforts needs to align with APS resource needs to provide value as a reliable energy resource. This can be achieved by emphasizing savings during high-cost, high demand late afternoon and evening hours rather than midday hours, when solar generation is abundant and wholesale energy market prices are low or negative. Shifting energy use through smart load management, energy storage and increasing midday load with beneficial electrification initiatives is emerging as an essential tool to reach future clean energy goals.

APS continues to closely examine opportunities for peak demand reduction technologies and programs. Reviewing a broad range of DSM programs and measures, each one is assessed for its peak coincidence factor potential (likelihood that the measure provides energy savings at the time of the system peak) and for its impact on 8,760 hourly annual load shapes, particularly its ability to improve duck curve issues. APS is already evolving the current DSM portfolio toward peak demand management programs that will provide high value to customers and align better with system resource needs.

APS is implementing several new DSM programs, including the Rewards portfolio of demand response, energy storage and load management distributed energy resource technologies that recently won industry innovation awards from the Association of Energy Services Professionals (AESP), the Peak Load Management Alliance (PLMA) and the Smart Electric Power Alliance (SEPA). In the past three years, APS has also proposed several new programs and pilots in the 2018 DSM Implementation Plan (filed September 1, 2017), the 2019 DSM Implementation Plan (filed December 31, 2018) and the 2020 DSM Implementation Plan (filed December 31, 2019, amended May 18, 2020) that would use emerging distributed energy resource technologies to better align DSM activities with the Company's changing resource needs, including:

Beneficial Electrification Pilot (proposed in 2019-2020 DSM Plans)

Beneficial electrification is a rapidly emerging area of DSM programs nationwide because it offers a wide range of benefits for customers, including improved efficiency, reduced energy costs, lower air emissions and improved health and safety. It also provides essential flexible loads for the energy system that will help to integrate renewable energy and flatten system load shapes while supporting APS's clean energy goals. APS proposed two beneficial electrification measures in the 2019 DSM Plan, standby truck refrigeration and propane forklifts conversion, and three additional airport electrification measures in the 2020 DSM Plan.

Electric Vehicle Load Management Pilot (proposed in 2020 DSM Plan)

As electric vehicle adoption increases, it is becoming essential to consider the energy and demand needs of EV charging. DSM programs can be developed for customers to establish beneficial charging patterns that help manage peak demand and time charging to occur when excess renewable energy is available, whenever possible. APS has proposed a new EV load management pilot program that will use a combination of approaches to manage EV energy use, including working with charging stations to manage charging loads during peak periods and creating a rewards program to encourage customers to charge their vehicles off-peak.

New Home Connected Community Research Project (proposed in 2018-2020 DSM Plans)

APS is proposing an applied research project within the "Measurement, Evaluation and Research" element of the DSM portfolio. The project will work with a small number of participating home builders who are willing to install connected smart devices such as smart thermostats, connected electric water heating controls and home energy management systems in a large percentage of homes in a community. These products will provide the ability to understand the opportunities and challenges of managing community distribution feeders with a large scale of distributed energy resources in place.

APS Rewards (Demand Response, Energy Storage and Load Management) Program

The Residential Demand Response, Energy Storage and Load Management program (filed in accordance with Decision No. 75679)[4] supports the deployment of residential load management, demand response and energy storage technologies that help APS residential customers shift energy use and manage peak demand while providing system peak reduction and other grid benefits. The program includes several elements: Cool Rewards (demand response with residential smart thermostats), Storage Rewards (customer-sited battery storage), Reserve Rewards (connected heat pump water heaters used as thermal energy storage) and IFES (feeder-scale battery storage). The

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[4] A.C.C. Docket No. E-01345A-15-0182.

program has achieved or exceeded all its pilot goals for customer participation and load management capacity and has earned three major DSM industry awards. In particular, the Cool Rewards smart thermostat demand response program currently includes more than 20,000 participating thermostats that are capable of reducing more than 25 MWs of peak demand during DR events.

DSM Programs in Development

Increasingly, the future of DSM involves an integrated approach to distributed energy resources for managing energy demand and shifting load not only on the grid as a whole, but also in specific locations to help defer the cost of distribution related upgrades. As connected devices become more economic and integrated with each other, these resources will offer more instantaneous demand response capabilities – optimizing the operation of key appliances to save customers money while offering benefits for utility operations. APS is currently conducting and proposing multiple programs to further explore integrated distributed energy resource solutions. In such a changing environment, it is important to maintain an open dialogue about how DSM tools can be expanded and applied to more appropriately value the benefits of load management in meeting resource needs while achieving credit toward any future DSM and clean energy policy goals.

In 2019, APS conducted an EE Opportunity Study that was closely coordinated with DSM stakeholders. The study provided updated information on the technical, economic and achievable potential from a number of traditional and emerging energy efficiency technologies and program opportunities. From this study, APS identified a number of new EE opportunities for non-residential customers that were proposed in the 2020 DSM Plan, including efficiency measures targeted to apply to the increasing load from computer server facilities (data centers) that are expanding in the APS service area. This study is currently being enhanced with a second phase looking at flexible distributed capacity opportunities from DSM, including a focus on load shifting, demand response, storage and beneficial electrification potential. The Company is using the data collected from these studies in conjunction with information from current and historic DSM program activity to develop more granular DSM planning tools that support future load forecasting and integrated resource planning needs.

DSM Economic Considerations[5]

The economics of DSM programs can be evaluated by using five cost-effectiveness tests defined in the California Standard Practice Manual. These cost-effectiveness tests include the Participant Cost (PC) test, Ratepayer Impact Measure (RIM) test, Program Administrator Cost (PAC) test, Total Resource Cost (TRC) test and Societal Cost (SC) test. The Arizona Corporation Commission currently uses the SC test as the sole test to evaluate energy efficiency programs. Although APS shares the Commission's view that the SC test can be a useful assessment tool, the Company recommends that additional tests be used to evaluate the economics of DSM programs because each test provides a distinct perspective on the costs and benefits of a particular DSM program. In this broader approach, the SC test could still be used in conjunction with any or all of the other four tests to evaluate additional considerations for a particular DSM program. The use of additional tests such as the RIM and PAC tests can assist in ranking similar programs when considering program implementation. In addition to program ranking, the RIM test also evaluates the average rate and/or shifting of revenue burden from DSM customers to non-DSM customers. Given the perspective the RIM test provides to all customers, both participants and non-participants, it is very useful in evaluating the cost shift or equity of particular DSM programs.

OVERVIEW OF COST-EFFECTIVENESS TESTS

- PC Cost Test: Assesses the value of a program only from the potential participants' financial perspective. It compares a customer's bill savings with the capital investment in DSM measures.
- RIM Test: Evaluates a program's impact on non-participating customers, i.e., the shifting of revenues from participating customers' bill savings to non-participating customers.
- PAC Test: Compares the total costs of providing energy service or revenue requirements before and after the addition of DSM programs to the system.
- TRC Test: Evaluates the total costs of DSM programs, including costs incurred by both the participating customers and the utility.
- SC Test: Provides an economic evaluation similar to the TRC test but also includes externalities such as health improvements.

Utilizing these cost-effectiveness tests in the evaluation of supply- and demand-side resources provides insight into resource selection from multiple perspectives. In particular, the RIM test can be used to rank programs that provide more value or that have lower cost/rate impacts on customers as a whole. The appropriate balance of programs with emphasis on costs as well as other factors is essential to obtaining a balanced resource mix. This approach to costs and benefits is related to the rapidly changing regional resources and the associated energy mix. The widespread deployment of non-curtailable solar, in particular, has contributed to wholesale market conditions that at times have produced low or negative avoided energy prices. The same phenomenon has created a need for additional quick ramping, peaking units to serve growing peak demands after the sun goes down.

[5] The cost tests in this section can be utilized to determine the cost-effectiveness and cost-shift related to rooftop solar as well.

Generation Resources

In assessing generation resource options available, APS considered several technologies in nuclear, coal, natural gas, grid-scale solar, rooftop solar, energy storage and other renewable energy technologies.

TABLE 2-4. LIST OF FUTURE GENERATION RESOURCE OPTIONS AND ASSOCIATED COSTS

FUTURE GENERATION RESOURCE OPTIONS	CAPTIAL COSTS ($/KW)
NUCLEAR	
AP1000 Hybrid	$6,830
Small Modular Reactor (SMR)	$5,605
NATURAL GAS (Hydrogen Capable)	
Large-Frame Combustion Turbine	$652
Aeroderivative Gas Turbine	$1,512
Combined Cycle	$994
MICROGRID	
Gensets	$946
GRID-SCALE SOLAR	
Thin Film Solar PV - Single Axis Utility	$1,160
Thin Film Solar PV - Fixed Utility	$1,084
Solar PV + Battery Energy Storage System (PVS)	$2,385
Solar Thermal Tower with Storage	$7,107
ROOFTOP SOLAR	
Thin Film Solar PV - Fixed Commercial	$1,260
Thin Film Solar PV - Fixed Residential	$2,687
ENERGY STORAGE	
Battery Energy Storage System (Li-ion)	$1,225
Compressed Air Energy Storage (CAES)	$3,878
Pumped Storage Hydro	$3,546
Flow Battery	$1,570
OTHER RENEWABLE ENERGY SOURCES	
Arizona / New Mexico Wind	$1,343
Geothermal	$3,034
Biomass	$4,666

Notes:

Numbers in Table 2-4 are $ per installed kilowatt.

Some generation resource options provide less output towards meeting system peak.

Overnight construction costs in 2022 dollars and do not include Allowance for Funds Used During Construction (AFUDC).

Storage duration is four hours for each energy storage technology.

Solar: Grid-Scale

OVERVIEW AND RISK CONSIDERATIONS

Bloomberg New Energy Finance (BNEF) projects that U.S. installed grid-scale PV capacity will increase to 100 GW in 2025.[6] The grid-scale PV boom is well underway, with developers shifting attention to construction and project delivery. Forecasts of 60 GW through 2025 is underpinned by developers safe-harboring enough tax credits to drive record build.[7] The cost of grid-scale solar is expected to decline, but at a more gradual pace than in the past.

Many factors previously viewed as risks of grid-scale solar are being addressed by more versatile plant design and by coupling them with energy storage systems. These changes help to curtail output during the low load hours, if necessary, and/or store energy so that it can be put back into the grid to meet peaking needs after the sun has set. This is becoming more important as regional solar penetration increases and stand-alone solar capacity value diminishes.

INVESTMENT TAX CREDIT (ITC)

Section 48 of the Internal Revenue Code provides an ITC for certain solar and other renewable energy property. The credit is subject to the following phase-down schedule:

- 30% ITC for projects that begin construction before 2020 and are placed in service before 2024,
- 26% ITC for projects that begin construction in 2020 and are placed in service before 2024,
- 22% ITC for projects that begin construction in 2021 and are placed in service before 2024, and
- 10% ITC for projects that begin construction after December 31, 2021 or are placed in service after 2024.

TECHNOLOGIES

SOLAR PV FIXED AND SINGLE-AXIS TRACKING (SAT)

Fixed systems are typically angled at latitude for optimum production, while SAT systems rotate to follow the sun from east to west. Adding SAT increases the energy output from the system by approximately 25% in comparison to a fixed system.[8] It also increases the value of the energy delivered, as a portion of that additional output is in the late-afternoon hours when load is at its peak. In a grid-scale solar plant, thousands of solar modules are connected together to form large systems connected to the grid. Grid-scale inverters typically range in scale from 500 kW to over 1 MW. Many of these inverters are combined together to form multi-MW solar power systems.

PV WITH STORAGE (PVS)

As noted above, PV systems can be directly paired with energy storage systems such as batteries to increase dispatchability and dependable capacity to the grid. Greater efficiencies are possible with paired systems than with separate PV and storage systems. Charging the batteries exclusively with solar energy for the first five years enables them to receive the same ITC as solar generation.

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[6] BNEF H1 2020 U.S. Renewable Energy Market Outlook (April 8, 2020), BloombergNEF.

[7] BNEF H1 2020 U.S. Renewable Energy Market Outlook (April 8, 2020), BloombergNEF.

[8] Solar Power World, How does a new single-axis tracking process increase solar plant efficiency? (June 16, 2015), http://www.solarpowerworldonline.com/2015/06/how-does-a-new-single-axis-tracking-process-increase-solar-plant-efficiency/.

SOLAR THERMAL TROUGH TECHNOLOGY WITH SALT STORAGE

Parabolic troughs are the most mature concentrated thermal solar power technology.[9] Parabolic mirrors focus solar energy onto a receiver tube that contains a heat transfer fluid, typically synthetic oil. The fluid then returns to a series of heat exchangers, where it is used to generate superheated steam at about 1,450 psia and 700ºF. The steam is then used to run conventional steam turbines. Spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers as condensate via the feedwater pumps.

With the addition of molten salt thermal storage, like that used at Solana, or gas hybridization, these systems can extend the generation period up to six hours or more after sunset.

PARABOLIC TROUGH, GAS HYBRID

Parabolic trough gas hybrid systems inject solar steam into a common turbine, which is also supplied by the natural gas plant, giving the flexibility to generate electricity from either or both of the natural gas and solar facilities as needed.[10] The 75 MW Martin Next Generation Solar Energy Center was the first hybrid solar facility in the world to combine a solar thermal array of more than 190,000 mirrors with a combined cycle natural gas power plant.

CENTRAL RECEIVER (POWER TOWER) - SALT STORAGE

In power tower concentrating solar power systems, flat, sun-tracking mirrors, known as heliostats, direct sunlight onto a receiver located at the top of a tall tower. A heat-transfer fluid is used to heat a working fluid, which then produces electricity in a conventional turbine generator.[11] Power towers can operate by heating water directly, such as the Ivanpah Generation Station in California, or they can heat molten salt directly for thermal storage and steam generation, such as the Crescent Dunes project in Nevada.

Wind

OVERVIEW AND RISK CONSIDERATIONS

U.S. wind was set for record annual build in 2020 and breakneck construction to ensure projects commissioned by year-end to secure full tax credit benefits. BNEF expects 55 GW of wind to be built in the United States between 2020 and 2025.

PRODUCTION TAX CREDIT (PTC)

Section 45 of the Internal Revenue Code provides a PTC, a federal financial incentive for the development of certain renewable energy facilities. The credit is based on kilowatt-hours produced and is currently on a phase-down schedule. Recently, the PTC was extended under the Taxpayer Certainty and Disaster Relief Act of 2019. For facilities that began construction prior to 2017, the credit is 2.3 cents/kWh for 10 years, adjusted for inflation in the year the electricity is produced. For facilities that begin construction after December 31, 2016, the following reductions to the 2.3

[9] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Parabolic Trough, https://energy.gov/eere/sunshot/parabolic-trough.

[10] Solar Industry, FPL Generates Electricity And Experience at Martin Hybrid Solar Facility, http://solarindustrymag.com/online/issues/SI1502/FEAT_01_FPL-Generates-Electricity-And-Experience-At-Martin-Hybrid-Solar-Facility.html.

[11] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Power Tower System Concentrating Solar Power Basics (August 20, 2013), https://energy.gov/eere/energybasics/articles/power-tower-system-concentrating-solar-power-basics.

cent/kWh credit level generally apply:

– 20% reduction for projects beginning in 2017,
– 40% reduction for projects beginning in 2018,
– 60% reduction for projects beginning in 2019,
– 40% reduction for projects beginning in 2020, as provided for in the Taxpayer Certainty and Disaster Relief Act, and
– No credit for any facility beginning construction after December 31, 2020.

In lieu of the PTC, taxpayers of certain wind projects may make an irrevocable election to claim the ITC. If such an election is made, the above PTC reductions also apply to the ITC, allowing for credits as follows:

– 24% ITC for projects beginning in 2017,
– 18% ITC for projects beginning in 2018,
– 12% ITC for projects beginning in 2019,
– 18% ITC for projects beginning in 2020, as provided for in the Taxpayer Certainty and Disaster Relief Act, and
– No credit for any facility beginning construction after December 31, 2020.

Like other renewable energy resources, the primary challenge of wind energy is its variable generation, depending on the region. High levels of wind energy production often occur in the spring when APS's customer loads are at reduced levels, and low levels of production in the summer, resulting in wind energy's contribution to meeting summer peak demand to be a fraction of the rated generation output. However, energy storage projects can allow this technology to make a meaningful contribution to APS's clean energy future.

TECHNOLOGY

Wind systems convert the wind's energy into electricity by using rotating blades, typically made of fiberglass, to collect the wind's kinetic energy. The turbines are supported by a conical steel tower that is widest at the base and tapers in diameter to just below the nacelle. The nacelle is attached to the top of the tower and contains the primary mechanical components of a wind turbine. The blades are connected to a drive shaft that turns a generator to produce electricity.

APS has PPAs for three wind farms, two in New Mexico and one in Arizona.

Geothermal

OVERVIEW AND RISK CONSIDERATIONS

The U.S. Energy Information Administration (EIA) projects that geothermal net summer capacity will increase from 2.3 GW in 2019 to 4.7 GW in 2035, in its reference case.[12]

Geothermal energy provides carbon-free baseload power, which is primarily addressed in APS's service territory by Palo Verde. Other considerations include the location of geothermal resources, which are generally distant from the Company's load centers and transmission infrastructure. Moreover, a geothermal project must go through identification, exploration and drilling phases before production can begin, and lead times for these facilities tend to be longer and development costs higher than for other renewable resources.

[12] U.S. Energy Information Administration, Annual Energy Outlook 2020 (January 29, 2020), http://eia.gov/outlook/aeo/.

TECHNOLOGY

To generate electricity, geothermal power uses heat from a variety of sources below the earth's surface to generate electricity, including hot water or steam reservoirs deep in the earth and geothermal reservoirs and shallow ground near the surface of the earth.[13]

APS has a 10 MW PPA for geothermal energy from the Salton Sea in California.

Biomass & Biogas

OVERVIEW AND RISK CONSIDERATIONS

The EIA projects that biomass net summer capacity will increase from 3.1 GW in 2019 to 3.2 GW in 2035, in its reference case.[14]

Although biomass and biogas facilities utilize a combustion process that emits CO2, they are widely considered "carbon neutral" as carbon emissions are offset by the prior absorption of carbon through photosynthesis that occurred throughout the plant's lifecycle before being harvested to produce the source of waste.

In December 2018, the ACC adopted a policy for utilities to consider the role of forest biomass as a renewable energy source in Arizona. In an effort to support responsible forest management and the Commission's policy, APS subsequently analyzed the potential conversion of Cholla Unit 1 to burn biomass resulting from 4FRI forest restoration efforts. No action has been taken, and APS continues to work with stakeholders on options for a biomass solution. The U.S. Forest Service has issued an RFP, and APS expects that results of the RFP will provide additional information on potential next steps of a solution.

TECHNOLOGIES

BIOMASS

Biomass fuels are primarily wood or wood byproducts. However, they can include dried municipal solid wastes, feedlot and dairy manure, crop wastes and sewage digester sludge. Biomass can be converted into electricity in one of several processes. The majority of biomass electricity is generated today using a steam cycle where the biomass is burned in a boiler to produce steam. The steam turns a turbine, which is connected to a generator that produces electricity.

APS currently has a PPA with the Snowflake White Mountain Biomass Power Plant for approximately 50% of its output.

BIOGAS

Biogas is a low-BTU gas composed of methane (40-60%), carbon dioxide, water and miscellaneous contaminates. It is produced through anaerobic digestion processes in landfills wastewater treatment at municipal water plants and concentrating animal feeding operation farms. The gas is produced, collected and then typically flared and/or used for on-site thermal heating. If the amount of biogas produced is sufficient to warrant the development of a biogas-to-energy project, the biogas would be cleaned and dried, and/or thermally oxidized prior to combustion. The biogas can then be converted into electricity by combustion in specific reciprocating engines, microturbines and fuel cells that have been designed and configured to utilize low-BTU fuels.

[13] National Renewable Energy Laboratory, Geothermal Energy Basics, http://www.nrel.gov/workingwithus/re-geothermal.html.

[14] U.S. Energy Information Administration, Annual Energy Outlook 2020 (January 29, 2020), http://eia.gov/outlook/aeo/.

APS currently has a PPA with the 3.2 MW Northwest Regional Landfill in Surprise.

Energy Storage

OVERVIEW AND RISK CONSIDERATIONS

Achieving the clean energy commitment will require continued advances in energy technology. To help drive clean energy investment and innovation, APS will encourage policies that enable market-based solutions and serve as a driving force behind energy research and development. APS will continue to pursue the advancement of new and emerging technologies. Given the research, incubator labs, startups and investment involved in clean energy, the Company is confident emerging technologies will become proven and commercially available at competitive prices.

Energy storage – including pumped hydroelectric, compressed air, flywheel systems, hydrogen technologies and various types of batteries – will play a crucial role in harnessing increased levels of production and the intermittency of most renewable resources to meet the clean energy needs of customers. It has the potential to increase the value of renewable resources while improving grid reliability and stability. In renewable energy integration, storage's value comes in its ability to align solar energy production with peak energy demand and absorb excess renewable energy production in lower load hours, along with evening out the variable nature of renewable production. Solar energy generation is highest during midday hours, when most customers are at work and home energy usage is low. Conversely, when customers come home in the evening and increase their energy usage by turning on their air conditioners, washing machines, lights and TVs simultaneously, solar energy production has stopped because the sun has set – creating a mismatch between when rooftop solar installations produce energy and when customers need it. Storage addresses this misalignment by harvesting the solar energy that is produced during midday hours and then dispatching it in the evening during peak customer demand.

In the APS Solar Partner program, APS is assessing risks associated with storage technologies including:

- **Resource risk** – Storage does not produce energy so they are reliant on other resources, often variable resources, whose deployment has been driven by tax policies that may not be extended.
- **Market risk** – As with other resources, storage will be considered for dispatch on a cost-competitive basis against other resources.
- **Integrative capabilities** – Pairing storage with other resources, namely solar or wind, has limited operational experience and requires more "live" projects before these pairings can be viewed as seamless and reliable.

Through these small-scale projects and lessons learned from the 2019 McMicken incident, APS seeks to further understand energy storage's potential benefits and safety considerations, and to prepare for its wide-scale deployment, and validate its reliability and safety.

TECHNOLOGIES

LITHIUM-ION BATTERY

Lithium-ion battery systems are perhaps the fastest-growing battery technology in the marketplace today. The technology has already matured for cell phones and other stationary consumer electronics and is rapidly being expanded into electric vehicles. As of Q1 2020, there is approximately 300 GWh of annual lithium-ion battery production, with 745 GWh of annual production announced to be online by 2026.[15] While a huge portion of these batteries will be utilized by electric vehicles, utilities across the United States are also deploying the technology in grid-scale applications, with 1.5 GWh installed[16] and at least 38 GWh planned by 2024[17] which, if trends persist into the near future, will be a majority of lithium-ion.

The primary lithium-ion chemistry being utilized today by electric consumer vehicles and utilities are of the cobalt variety, usually nickel manganese cobalt (NMC). This chemistry provides a high energy density and have had a mostly continuous downward price trend due to manufacturing scale noted above. However, the primary chemistry being utilized in electric commercial vehicles (e.g., buses) is lithium iron phosphate (LFP), which provides a more thermally stable cathode (i.e., may be less prone to thermal runaway) and does not contain the more expensive raw materials found in NMC. LFP does have a lower energy density than cobalt-type chemistries. Because most utility energy storage applications are not highly space constrained, there has been some discussion in the industry around utilizing LFP for grid-scale projects. Concerns remain for LFP around the supply chain with the expected investment and production dominance that NMC is expected to have in the near future.

APS has installed 7.2 MW/14.4 MWh of lithium-ion storage in its portfolio since 2017, and it has been utilized for multiple applications, including capacity, energy shifting and power quality.

FLOW BATTERY

Reduction and oxidation (redox) flow batteries are a type of secondary battery in which the energy is stored in separate positive and negative electrolyte solutions that are pumped into a cell "stack" where ions are exchanged across a membrane to create the electrical current. Generally, flow batteries have an advantage over other secondary batteries in their ability to use the full state-of-charge (SOC) range, including resting SOC, without much concern for additional degradation. Degradation of flow batteries has been shown to be at much lower rates than other secondary batteries, but monitoring and management of the electrolytes, membranes and mechanical components must also be considered. Flow batteries are not prone to the same fire risks that other secondary batteries have, though corrosive electrolyte spills can occur, but are largely dependent on the composition of the electrolyte material. Lastly, the AC-AC round-trip efficiency of flow batteries is around 20-25% lower than lithium-ion. Similar to compressed air energy storage, flow batteries have a relatively high upfront cost with low marginal cost per additional MWh (bigger tanks of electrolytes), lending the technology to long-duration storage applications (6-plus hours). To date, flow batteries have not been commercially proven or available in the large capacities needed for bulk-grid utility applications, though there remains a lot of industry interest in the technology.

MOLTEN-SALT BATTERY

Molten-salt batteries utilize electrodes and/or electrolytes that are activated from a solid to a liquid through high temperatures and tend to have longer discharge durations (~5-plus hours). Sodium-sulfur (NaS) batteries are one such battery that uses very high temperatures (570 ºF) to create metallic sodium and sulfur electrodes. These systems must be kept at a high temperature because the batteries will be severely stressed if they are allowed to completely cool, though a lot of inherent insulation can keep them warm for hours or days. The lifespan of a NaS battery is comparable to, if slightly longer than, lithium-ion batteries. The first MW-scale NaS batteries were installed in 1997, and there are 530 MW/3,700 MWh of installed projects worldwide, mostly outside of the United States. Cost challenges with this technology have limited its deployment, though a 108-MW deployment in 2019 was commissioned in the United Arab Emirates.

[15] Wood Mackenzie, Power & Renewables – Global Li-Ion Battery Manufacturing Database, Updated 2/1/2020

[16] Wood Mackenzie, Power & Renewables – Global Front-of-Meter Energy Storage Projects Database, Updated 1/15/2020

[17] Wood Mackenzie, Power & Renewables – Global Energy Storage Forecasts Database, Updated 11/11/2019

LEAD-ACID BATTERY

Lead-acid battery systems are the oldest form of chemical storage, dating back to the 1800s. Issues arise with depth of discharge issues and weight of batteries when applied in automotive EV applications. They are designed more for quick pulses of high power applications but have issues with long sustained usage in utility storage applications. Advanced lead-acid battery technologies and carbon composite lead materials have allowed for greater depth of discharge and utility storage applications, but they are still maturing.

ZINC-AIR BATTERY

Zinc-air batteries utilize an electropositive metal in an electrochemical coupled with oxygen to generate electricity. Since they only require one electrode, the batteries can have high energy densities compared with other chemical energy storage. There can be some issues with the electrolyte not deactivating in the recharging cycle, which can reduce the number of times the battery can be recharged. The anode material is made from zinc oxide, which is easily recyclable and obtainable, yet the characteristics of the battery reduce charging/discharging efficiencies to 50%. Efficiency and maturity of this technology relative to lithium-ion have limited the deployment of this technology.

COMPRESSED AIR ENERGY STORAGE

Compressed air energy storage (CAES) is a bulk energy storage technology that utilizes either a below-ground cavern or above-ground storage tank to store energy as compressed air to later turn that energy into electricity through a natural gas combustion turbine or turbo-expander. There are currently only two functional grid-scale CAES systems, one in Germany and one in Alabama, both using underground caverns. These plants have been in operation for 30-plus years with minimal maintenance needs compared to other thermal generation power plants. One recent variant of CAES compresses air into liquid that can then be stored in above-ground tanks, thus avoiding the geographic restriction of finding a suitable underground cavern. CAES has a relatively high upfront cost with low marginal cost per additional MWh, lending the technology to long duration storage applications (6-plus hours).

PUMPED STORAGE HYDRO

Pumped hydro energy storage utilizes the pumping of water upwards against gravity during off-peak hours and then discharging the stored potential energy of the elevated water during peak times. This technology is mature. Pumped hydro plants have high efficiencies and a half-century of useful life. Water resource and environmental concerns have limited the growth of the technology since the 1980s. However, de-carbonization efforts require GW-scale, long-duration energy storage options, and pumped hydro has been receiving renewed attention for this reason.

FLYWHEELS

Flywheels are a type of mechanical storage in the form of angular momentum of a spinning mass. The flywheels are housed in a thick steel unit to prevent injury from failure of the spinning unit of the system. The steel enclosure is also used to eliminate friction through vacuum or low-friction gas magnets. Most flywheel systems are DC-coupled so would need an inverter to convert to AC power. Flywheels have much greater life than chemical storage, in excess of 100,000 full discharge cycles and a power density five to 10 times greater. Cost and technology maturity challenges have limited the deployment of this technology.

CONCRETE GRAVITATIONAL POTENTAIL ENERGY STORAGE

Concrete gravitational potential energy storage is an emerging technology in which stackable concrete blocks are raised to store energy and lowered to release it by spinning a reversible motor-generator. System components include thousands of blocks weighing tens of tons each, a multi-armed crane, trolleys, reversible hoist motor-generators, a block lifting system, sensors, cameras and control software. Potential energy is stored by lifting the blocks from a ground level stack to a tall stack using the reversible DC hoist motor-generators in motor mode. Kinetic energy is released and converted to electricity when blocks from the high stack are returned to the ground by gravity with the hoist motor generators operating in generator mode. This technology offers long-lasting, eight-hour energy storage installations at approximately 20% of the cost of lithium-ion batteries. The first commercial installation is under construction in India.

Carbon Capture and Sequestration

OVERVIEW AND RISK CONSIDERATIONS

Effective carbon capture could complement deeper penetration of renewables in a future with substantial decarbonization. Currently, almost all existing fossil-fuel generators do not control carbon emissions the way they control emissions of other air pollutants such as sulfur dioxide or nitrogen oxides. At the same time, these generators are dispatchable: They can supply energy quickly as needed for reliability. As the electricity sector moves toward deeper levels of decarbonization, carbon capture technologies offer the potential to keep in operation existing generators that otherwise would need to be retired.

Carbon capture technologies can isolate atmospheric CO_2 and either sequester it permanently in geologic formations or convert it for use in products. There are a number of demonstration projects that show promise but are still being tested in real-world conditions. We will continue to monitor this emerging technology carefully.

Natural Gas

OVERVIEW AND RISK CONSIDERATIONS

In 2019, natural gas generation accounted for 35% of total U.S. electricity generation, and the EIA projected in its 2020 Annual Energy Outlook that percentage would slightly decrease to 34% by 2035 under its reference case.[18]

The primary risk associated with natural gas combined cycle technology has been the price of natural gas, which has a history of volatility. That volatility is not projected to re-emerge over the course of the Planning Period due to the technology advancements in hydraulic fracturing (fracking) and the resulting increase in available shale gas. In terms of price levels, the latest estimates from the EIA project natural gas spot prices at Henry Hub ($/MMBtu in 2019 dollars) showing modest and steady increases from $2.57/MMBtu in 2019 to $3.36/MMBTu in 2035 in the reference case.[19]

Combustion of natural gas emits CO_2, therefore, it is considered a bridge fuel in the APS clean energy commitment. To reliably and affordably meet customers' energy needs until new

[18] U.S. Energy Information Administration, Annual Energy Outlook 2020 (January 29, 2020), http://eia.gov/outlook/aeo/.

[19] U.S. Energy Information Administration, Annual Energy Outlook 2020 (January 29, 2020), http://eia.gov/outlook/aeo/.

technologies are sufficiently developed, however, natural gas generation will be necessary. In the long term, natural gas units will need to be retired, converted to hydrogen or equipped with carbon capture and sequestration technology. In the meantime, potential compliance liabilities related to fracking and increased demand for U.S. exports of this fuel in the transition period are risk considerations. A broader movement to regulate fracking at the state and/or federal level could have material effects on the future prices of natural gas.

Hydrogen

OVERVIEW AND RISK CONSIDERATIONS

Just as switching from coal to natural gas has driven large reductions in the power sector's carbon emissions, large-scale use of hydrogen has the potential to allow deep decarbonization of electricity production by 2050. Hydrogen burns with the reaction $2H_2 + O_2 \rightarrow 2H_2O$, which shows the exhaust from burning hydrogen is water. Industrial methods of manufacturing hydrogen produce CO2 as a byproduct. Emerging technology for generating hydrogen supports cost-effective and energy efficient carbon capture prior to combustion, creating the potential for natural gas-sourced hydrogen to serve as a cost-effective, carbon-free fuel alternative. When hydrogen is produced by electrolysis using zero-carbon electricity (from nuclear, solar or wind energy, for example), the resulting hydrogen is a zero-carbon fuel. Producing hydrogen when there is an excess of zero-carbon electricity effectively creates another energy storage technology for meeting peak demand with carbon-free electricity. The round-trip efficiency for this process is approximately 40%. Potential options for seasonal hydrogen storage include geological repositories and chemical hydrogen carriers such as methanol (CH_3OH) and ammonia (NH_3).

Today's high-efficiency gas turbines can burn fuel containing about 20% to 30% hydrogen with little or no modification. Some turbines for sale today are capable of 100% hydrogen combustion with no carbon emissions. Hydrogen power plants will still have to remove NO_X, an air pollutant that is produced when fuel is burned at high temperatures in air. Although hydrogen plants operate at slightly higher temperatures and produce slightly more NO_x than traditional fossil fuel plants, existing scrubbers are capable of removing it.

In addition to decarbonizing power production, hydrogen can be distributed through the existing natural gas infrastructure in concentrations up to 15% for use in manufacturing and other areas, thus enabling carbon reductions in other sectors. With modifications to existing natural gas infrastructure, transporting 100% hydrogen could be possible.

HYDROGEN CARRIERS

Because the costs of transporting and storing hydrogen can be high, it can be beneficial to consider synthetic fuels that contain large amounts of hydrogen but are easier to transport and store. Two such examples are ammonia and methanol.

AMMONIA

Ammonia is a 120-octane, carbon-free fuel made of hydrogen and nitrogen (NH_3). Relative to pure hydrogen, ammonia is inexpensive to transport and store. Ammonia can be burned in special combustion turbines and reciprocating engine generators to make clean, carbon-free electricity. It is possible to burn a mixture of hydrogen and ammonia in existing natural gas plants, but additional work is needed to reduce NO_X. Progress is being made in the area of using electricity to produce ammonia as a way to store green energy. For many decades, ammonia has been produced in large chemical plants worldwide as fertilizer for the agriculture industry. Pure ammonia is classified as toxic and dangerous for the environment, so safe handling and work practices would be of paramount importance.

METHANOL

Methanol is a carbon-containing hydrogen carrier with the chemical formula CH_3OH. Methanol is well suited for burning in internal combustion engines and can be transported and stored in existing petroleum industry infrastructure with minimal upgrades. As emerging technologies for direct air carbon capture mature, methanol could become a viable alternative for carbon-neutral power generation.

TECHNOLOGIES

The following technologies currently use natural gas as fuel but could potentially be fueled by hydrogen or hydrogen carriers such as ammonia in the future.

CONVENTIONAL AND ADVANCED COMBINED CYCLE (CC)

A CC generating unit consists of one or more combustion turbine (CT) generators equipped with heat recovery steam generator (HRSG) to capture the otherwise wasted thermal energy remaining in the turbine exhaust gases. Steam produced in the HRSG powers a steam turbine generator to produce electric power, in addition to the power produced by the CT(s). The process significantly increases the efficiency of this electric generating unit, and additional capacity can be obtained using power augmentation technologies, including turbine inlet cooling of the compressed air, duct firing at the inlet of the HRSG and steam injection.

APS installed three combined-cycle units at West Phoenix in 1976. Since then, APS has added two additional units at West Phoenix and two units at Redhawk. Additionally, APS has contracted for the output of merchant combined cycle units in the region for many years. Depending on the development of storage technologies, PPA contract extensions may be one way for APS to bridge to a clean energy future without making additional long-term investments in natural gas generation.

SIMPLE CYCLE COMBUSTION TURBINES

A CT generating system consists of an inlet air filter, inlet cooling system, compressor, combustor, turbine, exhaust environmental controls, stack, generator and auxiliary systems needed to support the operation of the CT. Many of the newer units are now capable of a 10-minute quick start or sometimes faster. Most are also considered to have low emission combustion and controls, along with improved part-load performance.

APS has owned and operated CTs since the first units were installed at the Yucca Power Plant in 1971. Currently, the Company operates 29 CTs, positioned across its service territory to support local grids. Yucca, Douglas, Saguaro, Ocotillo, West Phoenix and Sundance all have CTs on-site.

AERODERIVATIVE GAS TURBINE

One type of combustion turbine is the gas aeroderivative turbine, which is used as a compression device to take in air, compress the natural gas (or potentially hydrogen) then apply heat to the mixture with a burner. The hot air produced from this process powers the turbine.[20] Some benefits of aeroderivative turbines are fast-starting capabilities, the reduction in fuel consumption (about 10%) and improvement in operating duration (about 2%), as they avoid the long downtime maintenance cycles associated with other turbine types.[21]

APS employs these types of units at Sundance and Yucca (LM6000) and added LMS100 units at Ocotillo as part of the plant's modernization.

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[20] Turbine TECHNICS, Understanding Aeroderivative Gas Turbines, http://www.turbinetechnics.com/about-us/understanding-aeroderivative-gas-turbines.

[21] U.S. Department of Energy, Office of International Affairs – Understanding Natural Gas and LNG Options (February 16, 2017), https://energy.gov/ia/downloads/understanding-natural-gas-and-lng-options.

RECIPROCATING ENGINES

Reciprocating engines operate by introducing a mixture of fuel and air into combustion cylinder, which is then compressed as the piston within the cylinder moves upward. As it nears the top, a spark is produced that ignites the air-fuel mixture. The pressure of the resulting exploding gases drives the piston down. The moving piston produces rotational energy used to generate electricity or drive a piece of equipment or machinery. APS currently has many backup power generators at electrical critical sites, including the emergency electric power requirements at Palo Verde.

These units can start and produce power within 15 seconds and are often used in microgrid applications, such as the APS microgrids at Aligned Data Center (in collaboration with Aligned Data Center, a subsidiary of Aligned Energy) and Marine Corps Air Station Yuma.[22]

Reciprocating engine generators that cleanly burn ammonia, a carbon-free hydrogen carrier, are expected to be commercially available by 2024.

STEAM GENERATION UNITS

These turbines operate similarly to coal steam turbines but utilize gas (or potentially hydrogen) instead of pulverized coal as their fuel source. In these units, fuel is burned within the boiler to produce subcritical steam in the boiler tubes at a typical pressure of 1,450 psi and temperature of 1,000° F. The subcritical steam is expanded through a steam turbine to produce electricity. The turbine steam is exhausted into the condenser, is condensed back to water, and then pumped back into the boiler tubes to repeat the cycle. These basic steam generation units have moderate efficiency, typically 33% to 35%,[23] once they are running. Modern combined cycle technology is more efficient, less expensive and more flexible, so it is unlikely that this technology will be deployed in the future. With the retirement of the Ocotillo Steam units in 2018, APS no longer has this technology in service.

Nuclear

OVERVIEW AND RISK CONSIDERATIONS

In determining whether to add new nuclear resources to a portfolio, several factors are considered. Special reports regarding the role of nuclear power have been published recently by various energy-sector organizations, such as the International Energy Agency (IEA)[24] and the World Energy Council (WEC).[25] These organizations advocate for a carbon-free energy policy future inclusive of nuclear. The use of nuclear power over the past 50 years has reduced carbon dioxide (CO2) emissions to an amount equivalent to nearly two years' worth of global energy-related emissions.[26] Included in that number is Palo Verde, which will continue to be the foundation of the clean energy portfolio for APS and the Desert Southwest.

Both government and industry are increasingly declaring clean energy goals. Nuclear power provides a unique option for enabling a faster transition to a clean energy future. Globally, there are 47 new reactors scheduled to come online by 2026, adding nearly 52 GWe of capacity, a 13% addition to global nuclear capacity.[27] These projects are going forward with strong governmental support and

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[22] Microgrid Knowledge, How to Pay for Utility Microgrids? Arizona May Offer Answers (October 11, 2016), https://microgridknowledge.com/utility-microgrids-arizona/.

[23] NaturalGas.org, Electrical Uses, http://naturalgas.org/overview/uses-electrical/.

[24] IEA, Nuclear Power in a Clean Energy System, https://www.iea.org/reports/nuclear-power-in-a-clean-energy-system

[25] WEC, The Future of Nuclear, https://www.worldenergy.org/publications/entry/world-energy-scenarios-2019-the-future-of-nuclear-diverse-harmonies-in-the-energy-transition

[26] https://www.iea.org/publications/nuclear/

[27] World Nuclear Association, Plans For New Reactors Worldwide (Updated January 2020) https://www.world-

a robust construction infrastructure. In the United States, new nuclear construction has essentially stalled, with Southern Nuclear Operating Company's Vogtle Electric Generating Plant Units 3 and 4 the only new nuclear construction projects expected to enter service in the near term.

USED FUEL

In the United States, the long-term nuclear fuel permanent disposal repository is behind schedule, largely due to a lack of political support. Therefore, used fuel is currently safely stored onsite at nuclear plant locations around the country. In 2018, the U.S. inventory of spent nuclear fuel was approximately 82,000 metric tons of uranium (MTU)[28] and is projected to rise at a rate of approximately 1,800 MTU annually, resulting in an estimated 138,000 MTU by 2050.[29]

Countries that allow processing of used fuel are able to gain 25% to 30% more energy from the original uranium. All but 3% of the used fuel can be reused. Additionally, the level of radioactivity in the waste from reprocessing is much smaller than the original used fuel, and after about 100 years, the radioactivity from the used reprocessed fuel falls much more rapidly than in original used fuel.[30] Increasingly, today's used fuel is being seen as a future resource rather than a waste.[31]

TECHNOLOGIES

ADVANCED NUCLEAR REACTORS

Advanced reactors are considered cutting edge in nuclear technology and are grouped into three primary categories:

- Advanced water-cooled reactors, which provide evolutionary improvements to proven water-based fission technologies through innovations such as simplified design, smaller size or enhanced efficiency
- Non-water-cooled reactors, which are fission reactors that use materials such as liquid metals (e.g., sodium and lead), gases (e.g., helium and carbon dioxide) or molten salts as coolants instead of water
- Fusion reactors, which seek to generate energy by joining small atomic nuclei, as opposed to fission reactors, which generate energy by splitting large atomic nuclei

The Generation IV International Forum (GIF) identified the six most-promising advanced reactors and estimate that the earliest demonstration could be as early as 2030. Sodium-cooled fast reactors are considered to be the most mature. Gas-cooled fast reactors, lead-cooled fast reactors and molten salt reactors are not expected to reach commercialization until 2050 under current rates of development.[32]

Although very uncertain at this time, preliminary levelized cost of electricity (LCOE) for the "nth-of a-kind" (NOAK) reactor is estimated to be from \$60/MWh[33] to \$120/MWh.[34] Reactors are being

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nuclear.org/information-library/current-and-future-generation/plans-for-new-reactors-worldwide.aspx

[28] CURIE (accessed 2/6/2020), https://curie.ornl.gov/map

[29] Congressional Research Service, Advanced Nuclear Reactors: Technology Overview and Current Issues (April 18, 2019), https://crsreports.congress.gov/product/pdf/R/R45706

[30] World Nuclear Association, Processing of Used Nuclear Fuel (Updated June 2018), https://www.world-nuclear.org/information-library/nuclear-fuel-cycle/fuel-recycling/processing-of-used-nuclear-fuel.aspx

[31] World Nuclear Association, The Nuclear Fuel Cycle (Updated March 2017), https://www.world-nuclear.org/information-library/nuclear-fuel-cycle/introduction/nuclear-fuel-cycle-overview.aspx

[32] Researchers from MIT estimate that this timeframe may be moved up to the mid- to late-2030s under certain conditions. (Massachusetts Institute of Technology, "The Future of Nuclear Energy in a Carbon-Constrained World.")

[33] Energy Options Network, "What Will Advanced Nuclear Power Plants Cost? A Standardized Cost Analysis of Advanced Nuclear Technologies in Commercial Development" (Energy Innovation Reform Project, July 1, 2017), https://www.innovationreform.org/2017/07/01/will-advanced-nuclear-power-plants-cost/.

[34] Massachusetts Institute of Technology, "The Future of Nuclear Energy in a Carbon-Constrained World.",

designed to minimize the risk of release of radioactivity into the environment. Passive systems are in place to self-regulate the rate of fission and provide sufficient cooling of the core in the event of a loss of electricity or other active safety system. SMRs are expected to reduce construction costs.

Support for advanced nuclear reactors is available from the Federal Government through cost sharing, federal payments for power and research use, loan guarantees, tax credits (1.8 cents per kWh for 6,000 MWh per year for eight years), and Department of Energy hosting of private-sector experimental reactors. The Nuclear Regulatory Commission is developing a process to approve advanced reactors in a more efficient way, which includes approval of new design in stages, licensing project plans (includes commitments on the schedule and deliverables), and to increase the use of risk-informed/performance-based licensing and to issue a "technology-inclusive" regulatory framework.[35]

SMALL MODULAR REACTORS

A fourth, crosscutting category of advanced reactors is the small modular reactor (SMR).[36] The advantage of the SMR design is that major components can be built in a manufacturing facility and assembled at the site within a multi-module configuration, greatly reducing construction time and cost. However, there are some concerns that operating costs for SMRs may be higher due to their smaller size.[37] Several manufacturers are working on SMR designs, including NuScale, GE Hitachi, Holtec, Westinghouse and TerraPower. NuScale is the furthest along toward commercialization in the United States. It expects to complete its first commercially operational unit for Utah Associated Municipal Power Systems around 2025.

COGENERATION

Nuclear power has also been identified as a technology that can play a pivotal role in decarbonizing hard-to-abate sectors through co-generation, which is the integration with other systems and applications.[38] Co-generation provides many environmental and economic benefits through industrial applications, including desalination, hydrogen production, oil refining, biomass-based ethanol production and synthetic and unconventional oil production. Different options are available, depending on the reactor type.[39]About 20% of U.S. energy consumption goes into process heat applications, which predominantly use fossil fuels.[40] Process heat from various nuclear power designs has the ability to displace fossil-fuel usage, thus bringing economy-wide emissions down.

The hydrogen economy provides promising potential growth opportunities for nuclear power. In fact, APS is working Idaho National Laboratory on a hydrogen production project for Palo Verde. The project, which will run from 2020 to 2022, will produce hydrogen from water using electrolysis. The hydrogen will then be used for energy storage using reverse-operable electrolysis and as hydrogen gas to supplement peaking natural gas plants with a carbon-free fuel component. In its first phase, APS and INL will evaluate the project's technical and economic feasibility. If those results are promising, a second phase could involve a small pilot facility,

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http://energy.mit.edu/research/future-nuclear-energy-carbon-constrained-world/

[35] Congressional Research Service, Advanced Nuclear Reactors: Technology Overview and Current Issues (April 18, 2019), https://crsreports.congress.gov/product/pdf/R/R45706

[36] Congressional Research Service, Advanced Nuclear Reactors: Technology Overview and Current Issues (April 18, 2019), https://crsreports.congress.gov/product/pdf/R/R45706

[37] Congressional Research Service, Advanced Nuclear Reactors: Technology Overview and Current Issues (April 18, 2019), https://crsreports.congress.gov/product/pdf/R/R45706

[38] International Atomic Energy Association, Industrial Applications and Nuclear Cogeneration (accessed 2/17/2020), https://www.iaea.org/topics/non-electric-applications/industrial-applications-and-nuclear-cogeneration

[39] World Nuclear Association, Nuclear Process Heat for Industry (accessed 2/17/2020), https://www.world-nuclear.org/information-library/non-power-nuclear-applications/industry/nuclear-process-heat-for-industry.aspx

[40] World Nuclear Association, Nuclear Process Heat for Industry (accessed 2/17/2020), https://www.world-nuclear.org/information-library/non-power-nuclear-applications/industry/nuclear-process-heat-for-industry.aspx

Hydrogen is used for a number of industries, such as oil refining, steel manufacturing, ammonia production and as a critical feedstock for the chemical industry. New uses of hydrogen are emerging for consumer vehicles, long-haul transportation and energy storage. In the United States, 95% of hydrogen is produced by using natural gas. Globally, hydrogen production is responsible for annual CO_2 emissions equivalent to those of Indonesia and the United Kingdom combined. Internationally, 6% of natural gas and 2% of coal are used for hydrogen production. In energy terms, the total annual hydrogen demand worldwide is around 330 million tonnes of oil equivalent (mtoe), larger than the primary energy supply of Germany.[41] More than half of the world's hydrogen demand is for ammonia production. Nuclear power can be used to create hydrogen for clean ammonia fertilizer, enhancing food security worldwide.[42]

Coal

OVERVIEW AND RISK CONSIDERATIONS

According to the Energy Information Administration, declining capital costs for solar PV, environmental regulations and low natural gas prices are expected to contribute to a reduction in coal's share of total generation. The agency projects that, in the absence of the Clean Power Plan (CPP), the coal share of total electricity capacity will fall from 231 GW in 2019 to 128 GW in 2035 due to a combination of carbon reduction strategy, emission regulations, low natural gas prices and increased deployment of renewable generation.[43]

As part of its clean energy commitment, APS will cease all coal-fired generation by 2031. To the extent that new advanced clean coal technology could be a potential option, it would necessarily have to employ carbon capture and sequestration.

TECHNOLOGIES

SUBCRITICAL AND SUPERCRITICAL COAL STEAM BOILERS

Both subcritical and supercritical coal steam boiler technologies burn pulverized coal to produce steam in the boiler tubes at varying pressures, which then is expanded through a steam turbine that spins the generator to produce electricity. From there, the turbine exhaust steam is condensed back to water and returned to the boiler tubes for the cycle to start again. Supercritical boilers run at higher pressures and are more efficient than subcritical boilers. These and other generating technologies can be cooled by conventional wet cooling towers or dry air-to-air heat exchangers or a combination of both (hybrid).

TABLE 2-5. COAL STEAM BOILER TECHNOLOGIES

Coal Steam Boiler Technology	Operating Characteristics		APS Plants
	Pressure	Temperature	
Subcritical	<3,208 psi	1,025°F	Cholla Units 1-3
Supercritical	>3,208 psi	1,000°F–1,050°F	Four Corners Units 4 & 5

[41] International Energy Association, The Future of Hydrogen (June 2019), https://www.iea.org/publications/reports/thefutureofhydrogen/

[42] World Nuclear Association, Nuclear Process Heat for Industry (accessed 2/17/2020), https://www.world-nuclear.org/information-library/non-power-nuclear-applications/industry/nuclear-process-heat-for-industry.aspx

[43] U.S. Energy Information Administration, Annual Energy Outlook 2020 (January 29, 2020), http://eia.gov/outlook/aeo/.

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

IGCCs convert fuel such as coal to a synthetic mixture of hydrogen and carbon monoxide. It is then converted to electricity through a gas turbine process and steam turbine process that includes a heat recovery steam generator (HRSG).[44] There are two IGCC projects in the U.S., one built and the other cancelled. These do not appear to hold much promise at this time.

TWO LARGEST IGCC PROJECTS IN U.S.

1. Duke Energy's Edwardsport Generating Station, a 618 MW facility, was completed for $3.5 billion – $1.6 billion over the original $1.9 billion budget.[45] The facility currently does not include carbon capture and storage (CCS) technology.[46]
2. Southern Company's Kemper Project, a 583 MW facility that was supposed to include CCS technology designed to capture 65% of the project's CO2 emissions,[47] halted construction in 2017 due to cost overruns and the inability to get the plant to operate reliably. Project estimate: $7.5 billion.[48]

To Learn More

U.S. Department of Energy
https://www.energy.gov/

U.S. Energy Information Administration
http://www.eia.gov/

National Renewable Energy Laboratory
http://www.nrel.gov/

World Nuclear Association
http://www.world-nuclear.org/

[44] Massachusetts Institute of Technology, Laboratory for Energy and the Environment, An Overview of Coal based Integrated Gasification Combined Cycle (IGCC) Technology (September 2005), https://sequestration.mit.edu/pdf/LFEE_2005-002_WP.pdf.

[45] Indiana Public Media, State Regulators Approve Duke Energy Edwardsport Settlement (August 26, 2016), http://indianapublicmedia.org/news/state-regulators-approve-duke-energy-edwardsport-settlement-104185/.

[46] Orkas Energy Endurance, Kemper – Big Bang or Black Hole for Clean Cole (July 7, 2014), http://www.orkas.com/kemper-big-bang-or-black-hole-for-clean-coal/.

[47] Kallanish Energy, New delay in starting $7B carbon-capturing Mississippi plant (February 6, 2017), https://www.kallanishenergy.com/2017/02/06/another-delay-starting-7b-carbon-capturing-kemper-plant/.

[48] Regulators Back Settlement for Costs of Failed Kemper IGCC Project, Power Magazine 02/06/2018. https://www.powermag.com/regulators-back-settlement-for-costs-of-failed-kemper-igcc-project/

CHAPTER 3

MODERNIZING THE GRID

MODERNIZING THE GRID

Challenges and Opportunities in the Planning Horizon

The electric grid has seen an enormous amount of change in the last decade. Increasing loads and shifts to variable energy resources have amplified the grid's key role as an enabler of getting electricity from large renewable corridors to load centers. Additionally, policies to increase behind the meter generation have resulted in two-way electric flows that were not considered in the original design of the grid. Further, an influx of new consumer electronic goods such as electric vehicles and economy-wide electrification policies are expected to have profound effects on local utilization of the grid. Finally, the electric grid has generally been focused on expansion for decades to provide electric service to a growing population, however as that infrastructure ages, refurbishing and replacement is required. These changing realities require new ways of approaching the grid of the future. It will include the ability to look at alternative structures that maintain reliability and enable APS to meet its clean energy commitments but also mange efficiency and costs for customers.

The APS service territory continues to grow, which is discussed more fully in Chapter 5 of this IRP, as does customers' desire to adopt technology and make decisions about how they consume electricity. The continued growth of technology driven smart devices on homes, interconnectedness of all things electric via remote access through smartphones and entry of new electric intensive options such as EVs has led to new ways of approaching the design and buildout of the grid. But the keys to maintaining a reliable and affordable grid are having a view into how customers use electricity, evaluating data to project system design requirements, developing tools and providing feedback to customers to help recognize how electric usage and bills can be managed.

Preparing the grid for the dynamic nature of customer-sided resources working in concert with utility-scale resources is no small effort. APS has taken a number of steps to prepare the grid for this future reality and encourages customers to be a partner in this effort. The first major step was installing AMI meters for all customers which allows more granular view of data so customers can see how and when they are using electricity. This allows the customer to make informed decisions about their electricity usage from both a level of usage (traditional monthly bills) and also from a daily or hourly perspective to see when they are actually consuming energy. Perhaps, more importantly, AMI meters offer APS more granular, real-time information, that is used to maintain grid reliability and reduce customer outages. The information also offers APS planning teams insight to customer usage patterns to make projections and better informed decisions about future electric designs and investments.

The Company continues to work with stakeholders and customers to develop and evaluate programs that allow for cleaner energy use and more affordable electricity. For example, the APS rewards programs are part of its DSM suite of programs (see Chapter 2) that encourage shifting electric use that provides two key benefits. First, these programs shift energy into the middle of the day when solar production is highest, resulting in lower energy prices and clean energy consumption. Second, peak focused DSM reduces energy consumption in the evening, when the sun has set, electric prices are higher and fossil fuels are typically used to meet peak demand. Programs like these benefit customers in two major ways. With the first benefit, immediate savings occur on customer bills for shifting electric usage to lower priced periods of the day. The second key benefit reduces stress on the grid during peak demand, allowing APS to potentially defer additional capacity investments, saving all customers money.

Looking to the future, APS is currently developing a distribured energy resource management system (DERMS) to further enhance customers ability to interact with and manage the grid on a real-time basis. DERMS allows for the coordiantion of individual customer devices along with additions such as energy storage to keep the grid balanced and reliable across continuously varying levels of energy production and consuption. The DERMS system and assocaited benefits are more fully described below.

Defining the Modern Grid

Advanced technologies are driving the transformation to a modernized energy grid. These technologies allow full grid visibility, control and operating flexibility of the "backbone" infrastructure while simultaneously supporting integration of renewable energy and customer-connected devices. The grid continues to evolve to meet changing customer needs and make them active participants on the grid as they adopt technologies – such as EVs, rooftop solar, energy storage, smart appliances, energy management devices – that affect optimization and operation of the grid itself. With rising levels of technology adoption and customer participation comes increased potential for cybersecurity challenges that must be effectively managed and mitigated to make the modern grid a reliable, resilient reality.

This modern grid must:

- Provide full visibility and control to grid operators
- Continue to operate at high levels of reliability
- Have automated capability to quickly detect and isolate problems and restore service
- Integrate customer technologies including rooftop solar PV which may be paired with energy storage, electric vehicles, wi-fi connected thermostats and other evolving customer technologies
- Optimize operation considering customer technologies as part of the solution, and
- Securely and reliably manage data and information exchange to provide enhanced visibility, control and optimization options

The path to the modern grid requires strategic, long-term vision and investment in an appropriate technology mix, designed to update the decades-old infrastructure to enable integration of these newer technologies.

KEY OBJECTIVES

Maintain Reliability and Operational Flexibility

At its core, the APS system must be planned and designed to provide high efficiency and ensure availability of electricity to customers. This includes minimizing downtime for unexpected events and providing redundant paths that facilitate continuity of service to customers while faulted equipment is restored. As the volume of rooftop solar PV and other DER grows, the ability to monitor and maintain the system within acceptable thermal, voltage and protection criteria becomes even more essential to ensure a stable, balanced grid.

Empower Customers

Empowering customers to exercise choice and adopt technologies to interactively participate as energy producers and consumers relies on the ability of a utility grid operator to "see" what is happening, much like an air traffic controller. Customer DER introduces the two-way electricity flow from customer rooftop PV to the utility. This phenomenon opens the doors to real-time operations unprecedented in this industry's history. With increased visibility and control, smart grid systems expand situational awareness, letting utilities know about changes in localized customer demand and generation. This can lead to quicker response to grid conditions and maximize the grid's capability while minimizing potential negative impacts on the system or other customers.

Integrate Distributed Renewable Resources

Distributed energy resources such as solar PV present an opportunity to reduce the Company's carbon footprint but also come with challenges due to the physics of the system and customer demand – the right balance must be achieved on the grid. For example, the energy output of solar PV does not coincide with typical peak customer demand in Arizona. Solar produces the most energy in midday, while customers use the most in the late afternoon and early evening. Output variability during cloudy or dusty periods can be high, with loss of up to 90% of solar PV production from minute-to-minute, creating unacceptable power fluctuations from the "masked load" that was being served by solar PV.

Customer Benefits of Grid Modernization

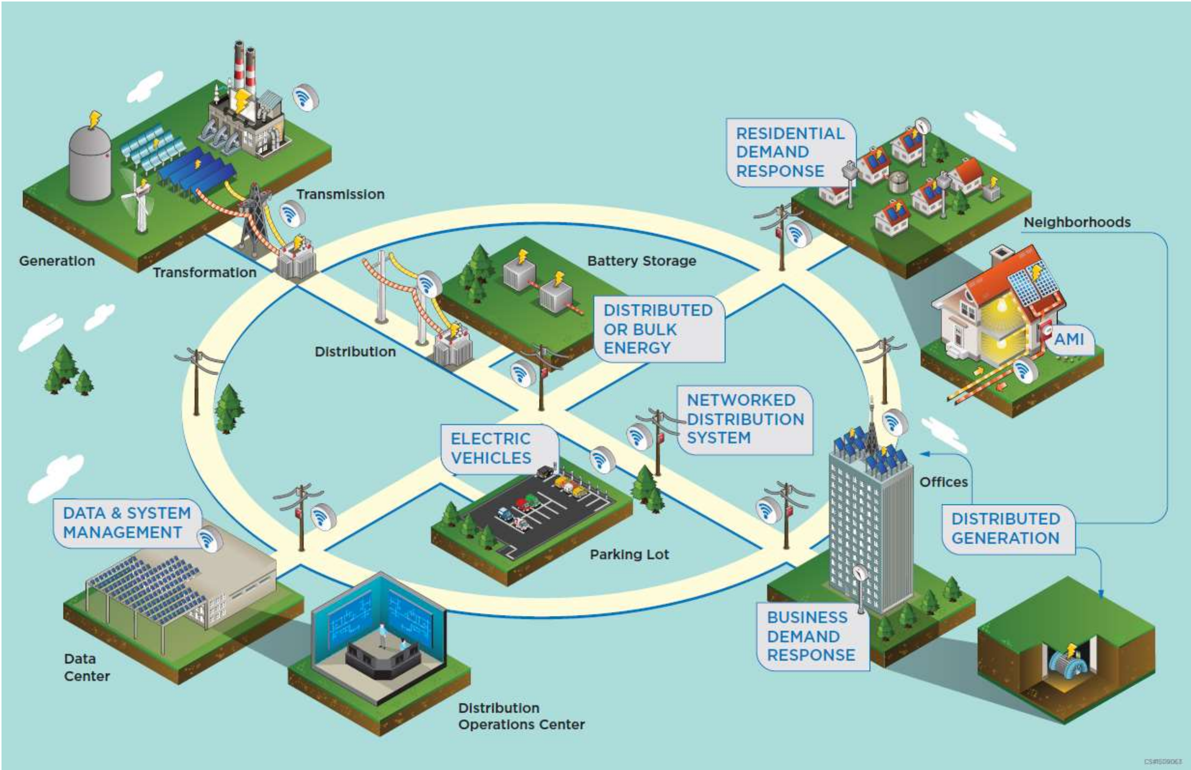
APS continues to be a leader in the industry related to DER adoption, specifically with rooftop solar. The Company recognizes that customers want to make their own energy decisions and is working toward solutions that integrate their choices seamlessly. Additionally, customers have unprecedented access to technology that improves their lives and makes them informed energy users. This creates both challenges and opportunities for the modern grid - balancing the instantaneous supply and demand of the grid with more resources and individual input can be offset with systems that seek to coordinate that usage. APS expects these trends to continue and the following sections more fully describe the steps the Company has taken, and the opportunities envisioned to enhance the customer experience.

ADVANCED METERING INFRASTRUCTURE (AMI) PROGRAM

AMI infrastructure has already been deployed in the APS service territory and is essential to obtaining data to enable customer involvement and grid design in the future. AMI is the collection of advanced billing meters, communicating devices and data management systems required to provide wireless electric metering and two-way communications between utilities and their customers. The benefits of AMI are more fully described below.

- Enables customers to manage costs by providing monitoring tools for energy usage, changing service plans or connecting and disconnecting service from their computer.
- Enables APS to offer a host of programs to give customers more choices, including a Preferred Due Date option. This allows customers to choose the payment date that best fits their lifestyle, varying the due date by a few days from one bill to the next.
- Enables APS to monitor voltage levels and power quality to help ensure reliable service and effectively plan for future energy needs.
- Provides safety and environmental benefits by avoiding millions of driving miles by APS employees to remotely perform customer read-ins, read-outs, rate changes, disconnects and reconnects.
- Produces substantial amounts of new data that can be transformed into actions such as reducing the number of unplanned transformer failures, identifying power outages and optimizing placement of future grid modernization technologies for even more enhanced performance, monitoring and control.
- New AMI technologies being deployed have the capability to support Distribution Automation (DA) devices on the same communications network as the meters, providing added grid monitoring and control with reduced installation and operations costs.

FIGURE 3-1. ADVANCED GRID ILLUSTRATION



DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM

APS is taking the steps today to better analyze data from both customer and company perspectives to coordinate the grid of the future. With technology advancements in solar power, electric vehicles, smart thermostats, grid interactive water heaters and home energy storage devices, APS customers are increasingly adopting energy technology with potential to impact the power grid. For this reason, APS is working toward implementing a distributed energy resource management system that will reduce the cost of keeping the power grid stable as customers bring more of these distributed energy resources online as well as help customers and the grid maximize the use of available renewable energy.

One of the key drivers for a DERMS is the need to properly align distributed generation with energy storage and smart devices. A prime example can be seen in Arizona's "Duck Curve" where the supply of energy does not coincide with peak customer energy usage. Supply tends to be at its highest mid-day (from PV generation) while the demand is highest later in the day (around 3 p.m.-8 p.m.). One of the key aspects of the DERMS is to ensure distributed energy resources are used as efficiently as possible, for both the customers and the grid.

By utilizing controllable loads and storage to increase energy uptake when solar production is at its highest, APS can ensure a clean energy source is being used most effectively. From the customer's perspective, utilizing energy earlier in the day allows individuals or households to take advantage of lower rates and avoid increasing electricity use on peak. And from a grid perspective, shifting load and reducing consumption during peak hours potentially reduces infrastructure required to maintain reliability.

One important consideration for the DERMS is optimization of distributed energy resources (DERs) recognizing that every customer has different needs. While energy efficiency programs are a win for both customers and APS (by potentially deferring upgrades to the grid and resulting in bill savings), DERMS will take the process a step further by tuning resources to the customer's specific needs. Additionally, the visibility and control the DERMS provides will give insights into how to better maintain power quality for APS customers and help further facilitate DER adoption on the grid.

Another consideration for the DERMS is the realization that not all DERs are created equal. The diversity of smart devices, energy storage and generation all bring value to the grid's health (and in reducing bills) and it is important to note the best way to operate each device varies greatly. While controllable loads and solar generation may appear straightforward, determining the "best" approach to utilizing energy storage or accommodating electrification of the entire grid is challenging for any individual. DERMS will not only account for the availability and cost to operate each device, but it will also assist in ensuring resources are coordinated across the entire grid, maintaining a reliable system.

Distributed Energy Resource Integration

The backbone of a modernized grid is a network management system that includes several technologies aimed at optimizing grid performance, reducing customer interruptions and enhancing system efficiencies. Since 2008, APS's solar customer base has grown from less than 200 to 110,000 In the same time period, APS customers have integrated more than 20,000 connected devices such as smart thermostats, more than 650 solar-plus-storage installations, 150 storage installations and emerging electric vehicle infrastructure, all requiring new technologies that can accommodate the operational changes these resources bring.

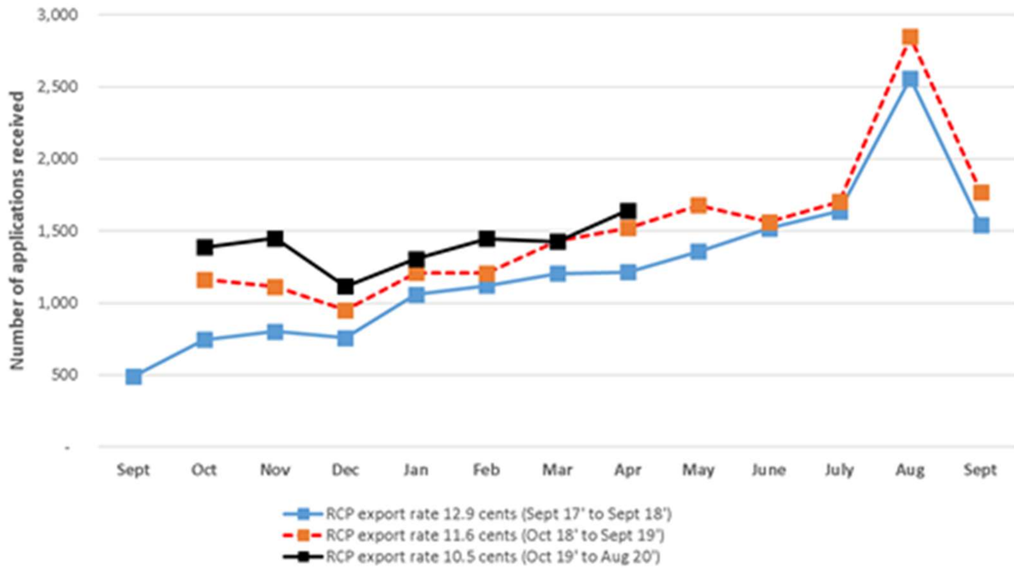
Distributed resources were once a customer technology that needed to be accommodated but now have become a resource that must be part of future grid planning. Grid modernization efforts facilitate the integration of these resources while simultaneously ensuring high reliability and power quality by providing system operators with greater visibility, intelligence and control options. As customers increase their level of interaction with the grid through new technologies available to them, a more distributed, agile and real-time grid will emerge.

ROOFTOP SOLAR

Customer adoption of residential and commercial rooftop solar PV throughout the APS service territory continues on a robust trajectory. As of June 2020, APS had approximately 110,000 total residential solar PV sites, and as shown in the chart below, application volumes continue to increase under the Resource Comparison Proxy (RCP) step-down approved by the ACC1. These distributed generators provide significant contribution to meet customer's energy consumption on the plus side. Yet the challenges of little production around system peak, weather-dependent output intermittency, power quality issues and load masking remain. These challenges must be solved via technology and intelligent grid operations.

[1] RCP Decision No. 77421

FIGURE 3-2. NUMBER OF RESIDENTIAL SOLAR INTERCONNECTION APPLICATIONS RECEIVED BY APS PER MONTH



The ACC approved new state-level DER Interconnection Rules in November 2019 that the Arizona attorney general made effective in February 2020, A.A.C. Article 26. The interconnection application process is now more clearly defined with utility, customer and installer roles and responsibilities. Highlights of the rules include application tracks based on system sizes, required fast-track screening, clear timelines and studies for feeder-level reliability assessments. Together, these provide a streamlined approach to interconnecting customer generation and storage while maintaining grid integrity and power quality for both solar and non-solar customers.

ENERGY STORAGE

Though still an emerging technology for grid management, APS has committed to 850 MW of energy storage by 2025. Residential-scale battery energy storage systems projects are also exploring the potential of this technology to help customers manage energy and demand through the Storage Rewards program. APS has learned a great deal about integrating energy storage into grid operations through its prior utility-scale projects. Energy storage will continue to scale to meet both grid modernization and resource planning needs, but both public and employee safety must be prerequisites for successful further energy storage deployment. The major benefit energy storage brings is aligning renewable solar PV production (stored in the day) with customer demand (discharged in the evening), offering the flexibility to use energy storage to manage grid fluctuations and potentially defer the need for new infrastructure.

As the technology continues to mature, costs decline and new applications are identified, batteries and other forms of energy storage are essential to maintaining a balance between energy production and demand while increasing clean energy on the APS system.

Advanced Grid Technologies

Digitizing the APS grid is an essential step in achieving success as a next-generation energy company. Operating under a more customer-centric platform and continuing advances in two-way communication technologies, grid health monitoring systems and hosting capacity information that can pinpoint optimal locations for rooftop solar interconnections are part of an intelligent network designed to increase power quality and system responsiveness.

Advanced grid technologies represent a growing suite of responses to the operational challenges associated with increasing levels of rooftop solar, offering protective measures to the wider energy system. These technologies can be used to contain outages by rerouting power and locating where repairs are needed, helping crews respond more quickly and reducing costs. These efficiency improvements also improve asset utilization, reduce line losses, enable advanced data management and analytics, and support sustainability efforts by reducing the use of inefficient resources to meet system needs.

By 2025, APS plans to invest in grid modernization technologies, system upgrades and related management systems through a number of project initiatives described below. In the past three years, more than 2,000 advanced grid devices have been installed on the APS system. Going forward, these technologies will be integrated into the Company's new advanced distribution management system, providing operators with a single view to operate the distribution grid.

TRANSMISSION PROGRAMS

APS is working to improve transmission reliability from an operational perspective through a number of projects, including:

Energy Management System (EMS) Upgrade Program

EMS is the main operational platform used to monitor, control and optimize the performance of the transmission system. EMS upgrades are expected to provide operators with an enhanced user interface and advanced analytical tools.

State Estimation/Real-Time Contingency Analysis

This tool allows the transmission operator the ability to run "what-if scenarios" and provides greater situational awareness of grid conditions through enhanced network models.

Advanced Visualization Tools

Providing visual analytics and robust reporting for improved operator risk management, these tools allow the operator to assess system conditions more rapidly without having to process a great deal of information or data.

Transmission Substation Health Monitoring (SHM) Program

This program is a family of transmission substation equipment monitoring technologies. Transmission SHM mitigates catastrophic transformer failures and increases system visibility for improved operator risk management.

Phasor Measurement Units (PMUs)

PMUs provide sub-second information about the operating characteristics of the transmission system that, in turn, provide the operator greater situational awareness of system conditions.

Uses include:

- Reducing the risk of major outages through the use of real-time data for improved operator risk management, and
- Post-event diagnostic capability through the analysis of disturbances and protection scheme performance

DISTRIBUTION PROGRAMS

Substation Health Monitoring (SHM) Program

SHM is a family of distribution substation equipment monitoring technologies that remotely monitor the health of transformer oil, transformer bushings and other substation equipment. Use of distribution SHM technology mitigates catastrophic transformer failures and increases visibility for improved operator risk management.

Distribution Automation (DA) Program

Integrated Volt/VAR Control (IVVC), Two-Way Capacitor Bank Controllers, and Automated Switching are subcomponents of the DA Program. IVVC mitigates low power quality and lowers the need for peak generation, transmission and distribution systems by continuously controlling regulators and capacitor banks to manage power quality such as power factor and voltage at the feeder level. Two-Way Capacitor Bank Controllers provide two-way communication and automation to capacitor banks to manage power quality and voltage. The Automated Switching subcomponent includes several hardware upgrades that automate the detection of problems along the distribution system and allows for remote operation and faster restoration of power.

Distribution Asset Monitoring (DAM) Program

DAM consists of two technology deployments:

- **Communicating Fault Indicators (CFIs) –** CFIs installed on distribution lines can be used to detect whether current is flowing on the line and then communicate that status via communications or visual indicators. CFIs provide near real-time voltage, current and fault information, which improve outage restoration times and limit equipment damage risk.

- **Network Protections (NP) –** NP deployment involves the installation of improved breakers, sensors and relays at existing NPs. These devices provide greater visibility of status, voltage and current in real time, in addition to increasing safety for field personnel. Historically, this data was obtained manually. Additionally, the Distribution Operations Center will be able to control the NPs in supervisory mode for enhanced operations.

Fire Mitigation Program

Fire mitigation technologies reduce the risk of fire caused by normal grid operations in a forested area. They also have the potential to help APS rapidly determine when equipment has failed and is in need of immediate attention in high fire-risk areas, and they limit the scope of potential hazards when equipment failures do occur.

Advanced Distribution Management System (ADMS) Program

ADMS is an advanced operational platform that manages the operations of the distribution system. It is comprised of three applications: Distribution Supervisory Control and Data Acquisition (DSCADA), Distribution Management System (DMS) and Outage Management System (OMS). Together, they provide an electric grid and individual asset health index, improve outage management (return-to-service), optimize trouble call management and enable condition-based maintenance programs for resource optimization.

Communication Infrastructure Program
Components include the installation of new optical fiber, expansion of the AMI network, private 900 MHz spectrum network, microwave communication devices and data management systems required to serve the overall needs of the enterprise in a secure and reliable manner.

Advanced Analytics, Data Management & Cybersecurity

ADVANCED ANALYTICS

Advanced Analytics evaluate the data being collected through grid technology and leverages this information to assess the technology's performance and help APS make decisions regarding what further investments are needed, if any. Advanced Analytics also promote a better understanding of customer usage through AMI meters. Areas of focus in this space have been Integrated IVCC, CFIs and Advanced Visualization.

DATA MANAGEMENT

Data Management covers the collection, storage, protection and deletion of new data that is being created through grid technologies. APS has established governance and stewardship practices to protect data accuracy and integrity. This helps maintain the data's value in making informed business decisions for the Company and its customers.

CYBERSECURITY

As cybersecurity attacks become more frequent and sophisticated across numerous industries, safeguarding the technology that delivers power to APS customers becomes increasingly important. There are also a growing number of vendors, suppliers and businesses with responsibility for managing the grid who are acting interdependently. A cybersecurity attack on one or more of these third parties could affect a utility's ability to manage grid activities.

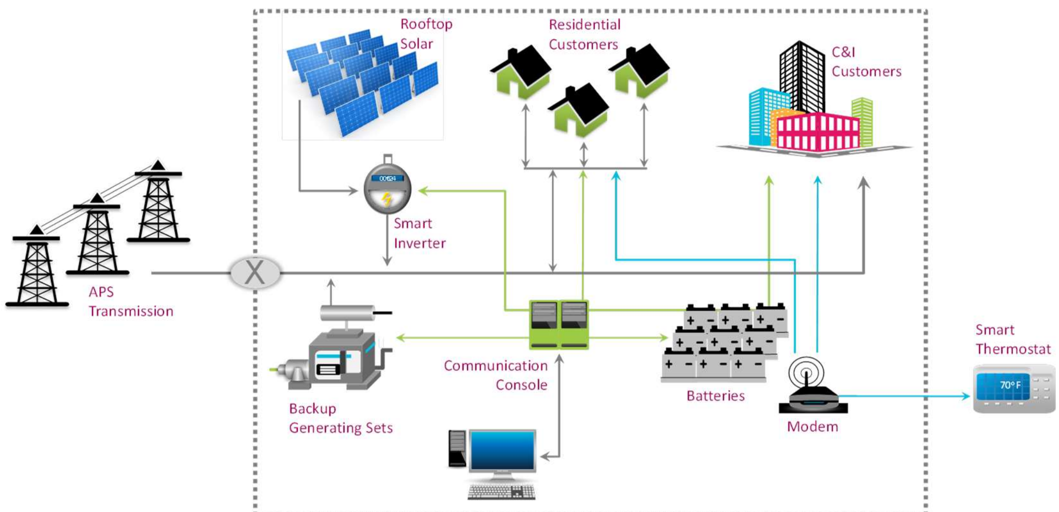
To protect customers against such risks, the comprehensive cybersecurity program is designed to prepare the Company's people, programs and technologies for emerging threats. The program is built on three essential elements: awareness, defensive posture and resiliency. Awareness includes employees taking an active part in the cybersecurity program. The cornerstone of the program is providing employees with the tools to recognize attacks using multiple delivery mechanisms, including tracking how employees respond and react to customized phishing emails sent to them throughout the year. Part of the Company's defensive posture is to deploy controls to prevent unauthorized use of removable media and theft of credentials that can be used to compromise or damage systems.

In 2016, the Company established the APS Cyber Defense Center (ACDC) to enable faster and more efficient responses to cybersecurity threats. To enhance resiliency, exercises are conducted quarterly to simulate emergent threats and scenarios that could arise from potential cybersecurity attacks and data breaches. The exercises ensure that incident response and business-restoration procedures are up-to-date and effective.

Microgrids

APS expects microgrids to play an increased role in how the Company supports business customers and economic development while simultaneously strengthening the grid. Microgrids are beneficial for APS's system and its customers as they increase reliability of the distribution grid, especially in the local area, by supporting the load where the microgrid is sited from the distribution system when it is approaching its limits. Microgrids can also be used for T&D deferral instead of replacing long runs of conductors as they approach thermal capacity limits. In addition, due to their fast-acting characteristics, microgrids provide ancillary services, such as frequency response, in the event of a grid disturbance. Finally, with the potential to add energy storage to these microgrids, their responsiveness can be improved along with increasing flexibility and emissions reductions as the energy storage system would respond to most events first and potentially avoid unit starts.

FIGURE 3-3. MICROGRID ILLUSTRATION



A microgrid is a part of the distribution grid that can separate (island) from the grid, continue operation, and reconnect with the grid at a later point in time without customer disruption. Having the ability to generate energy locally is a key benefit for all customers in the event of a distribution disruption or power quality event. Ongoing industry cost reductions in DER and secure communication platforms that provide the real-time command and management of local loads and resources has made the application of utility-led microgrids increasingly possible and cost-effective for customers.

Examples of suitable settings for microgrid projects include hospitals, military installations, data centers, universities, critical infrastructure, remote feeder locations and other customers with sensitive loads that cannot sustain loss of power. These customers traditionally procure their own back-up power systems to ensure continuous operation in the unlikely event of a power outage. APS partners with these customers to share in the cost and use of these resources, which have reliable and flexible operating characteristics to respond to their needs. These microgrids can integrate generators, energy storage and renewables making them flexible and adaptable for future capabilities.

In many of these applications, microgrid-capable DER installed at customer sites can act in a dual-use mode; one mode of operation provides peaking power to the grid in a grid-connected mode, benefiting all customers by acting as another peaking resource on the system and meeting APS planned resource requirements (plus reserve margin). The other mode of operation can provide backup power to the host customer in the event of a power outage. Microgrids also provide frequency response and load management capabilities for APS customers.

MICROGRID PROJECTS

In December 2016, APS, with the U.S. Department of the Navy and U.S. Marine Corps, launched the nation's first utility-owned, fully-islandable microgrid located adjacent to a 69KV substation, within the fence line of a DOD facility at Marine Corps Air Station (MCAS) in Yuma. This 21.6 MW project pioneered a new way to partner with a customer in which both parties make contributions to the project for the benefits of the direct (host) customer and APS customers in the Yuma area. The MCAS Yuma microgrid provides low-cost, reliable power throughout the summer peaks to all APS customers by backfeeding the grid from within the base facility and, in the event of a grid outage, the facility can provide 100% backup power to MCAS Yuma, enhancing national security. Due to the ability of the microgrid to go from zero to full output in under 15 seconds, it also provides frequency response services to the grid, which will further enhance the economics and savings of this facility for all customers.

FIGURE 3-4. MCAS YUMA

APS also worked with the Aligned Data Center to bring a 10.8 MW microgrid facility into service in the Phoenix metro area in December 2016. Similar to the MCAS Yuma microgrid, this facility can act as a peaking resource to the broader grid as well as provide backup power in the event of a grid outage.

Both microgrids have responded to a number of frequency response, load management and outage events as indicated in the table below (from March 2017-May 2020).

TABLE 3-1. MICROGRID EVENTS

Event Type	MCAS	Aligned
Under Frequency	116	83
Capacity	7	7
Island	4	1
Black Start	2	0
Total	129	91

APS anticipates increased customer interest in microgrids in the coming years. APS will meet this need by working to maximize value for the hosting customer and APS's overall customer base through delivery of resiliency, demand response and frequency response functionality.

CHAPTER 4

TRANSMISSION

TRANSMISSION

Approximately 1.3 million customers, in 11 of Arizona's 15 counties, depend on APS for reliable and affordable electric service. APS delivers electricity by relying on the planned network of transmission and distribution lines that safely transmit power from multiple large-scale generators to its customers. APS's Transmission Planning facilitates the development of electric infrastructure that provides customers access to both resources and markets while ensuring reliable service by employing a planning process that is timely, coordinated and transparent.

APS considers all technologies including generation, transmission, distribution resources and non-wires alternatives to address the challenges of an increasing array of resource types and higher than national average population growth, while remaining committed to providing least-cost and best-fit solutions. Toward this end, APS's Resource Planning and Transmission Planning teams work together along with counterparts across the state and the West, while actively engaging stakeholders to assure continued reliable and affordable power to customers.

In APS's 2020-2029 Ten-Year Transmission System Plan[1] (Transmission Plan), the Company detailed expansion and upgrades of its transmission system for approximately 26 miles of 230kV transmission lines, 3 miles of 115kV transmission line upgrades and 38 new transformers. These new transmission projects, coupled with additional distribution and sub-transmission investments, will support continued reliable power delivery and load growth in APS's service territory.

TABLE 4-1. SELECT PROJECTS FROM APS'S 2020-2029 TEN-YEAR TRANSMISSION PLAN

Project	Description	Construction Start Date	Construction End Date
North Gila-Orchard 230kV line circuit #1	To increase the ability to import resources into the Yuma load pocket and improve reliability of the local system	2020	2021
Runway 230kV lines	To provide electric energy to a new high load customer in the area.	2019	2021
Stratus 230kV lines	To provide electric energy to a new high load customer in the area.	2021	2022
Three Rivers 230kV lines	To provide electric energy to a new high load customer in the area.	2022	2023

[1] Arizona Public Service Company 2020-2029 Ten-Year Transmission System Plan, Docket No. E-00000D-19-0007.

KEY ISSUES

INCREASED DEPLOYMENT OF SOLAR ENERGY RESOURCES

Increased deployment of variable resources, especially rooftop solar, requires greater flexible capacity to respond to net load shapes, such as the duck curve. To achieve those objectives, resources that are capable of fast ramping with the ability to quickly turn on and off are essential to maintain the instantaneous supply and demand balance that the electric grid requires. The future grid will require a combination of customer-sided resources and flexible utility-scale resources to manage the increasing adoption of variable resources. The transmission system is the link that allows flexible integration of clean, utility-scale resources and provides affordable energy to all customers while balancing changing customer demand.

EXAMINING THE ABILITY TO IMPORT WIND RESOURCES

Wind resources available to APS are predominately in the northern portion of Arizona or in a neighboring state such as New Mexico and require the vast reaches of the transmission system to bring the clean energy to its customers in load centers. APS is determined to bring low-cost wind resources to its customers, which may require us to sometimes look to other wind-rich states such as New Mexico. APS is currently examining the ability of the transmission system to deliver out-of-state wind resources to the APS system. Today, APS takes delivery from three wind farms, one in Arizona and two in New Mexico, providing locational diversity to a variable resource that benefits APS customers greatly. But with locational diversity comes potential deliverability challenges, and APS's access to wind resources can be limited as a result. Out of state, high capacity factor wind resources are becoming increasingly difficult to secure due to the large number of utilities also seeking access to these resources. This creates challenges on APS's northern transmission system and neighboring utilities alike, with so many parties wanting access, there is not enough transmission capacity available. Further complicating this, APS's transmission system acts as the "Wind Energy Highway" from New Mexico to California, and the constraints created by this situation make adding wind to the Company's portfolio complex. From an in-state wind resource perspective, deliverability can take on a range of similar challenges. Generally, potential Arizona wind facilities are not always in close proximity to APS transmission lines. Gaining access to these wind facilities can pose significant additional costs due to required transmission buildout or upgrades. Wind energy will play a key role in Arizona's clean energy future, and APS is actively working through these dynamic challenges to provide clean and affordable wind resources to customers.

Reliability

APS has a responsibility to provide safe and reliable electric service to its customers. This is achieved through coordinated planning at all levels of APS to provide an integrated electric system capable of maintaining service under a variety of circumstances, including adverse weather conditions (both extreme heat and cold) and highly variable load conditions. To ensure resources are available when needed, APS performs planning in a holistic fashion. The Company considers the generation and transmission systems together by employing both probabilistic and deterministic approaches to assess the reliability of the entire system.

RESOURCE ADEQUACY

Resource adequacy assures sufficient capacity is available to the system to balance supply and demand for electricity. The portfolio of assets selected to best achieve those objectives is one that meets APS's planning principles and strikes the proper balance of anticipated needs for the Planning Period. Striking the proper balance can be a challenging endeavor as APS must also consider the addition of customer-sited resources and regional clean energy goals and policies that will add significant variable resources to the grid. In response, APS has published its Clean Energy Commitment which will strategically focus on the integration of clean energy resources in a reliable and cost-effective manner. This will include resources that are capable of turning on, ramping up and down, storing energy and turning off as needed to maintain the instantaneous supply and demand balance that the electric grid requires. APS's transmission system is the key component required to achieve system reliability under continuously changing load and resource requirements.

SYSTEM STABILITY & SECURITY

The electric grid is a physical system that requires thermal, voltage and frequency levels that do not exceed the limits of the transmission system under normal and contingency conditions. As such, grid connected resources contribute to the overall reliability of the system by providing voltage support and frequency balancing in addition to providing capacity. Many resources provide these capabilities to varying degrees and are increasingly important to offset less flexible and intermittent resources that are being quickly added to the electric grid. The result is a more complex system that still must maintain reliable operation for customers.

RELIABILITY COORDINATOR

Pursuant to NERC's Rules of Procedure (ROP), NERC and the Regional Entities are required to ensure that all Balancing Authorities (BA) and Transmission Operator (TOP) entities each are under the oversight of only one Reliability Coordinator (RC). The RC is responsible for maintaining the operating reliability of its area in real time and coordinating with its adjacent RCs wide-area view, which includes being situationally aware of activities in neighboring RCs that may have an impact on or within its RC area.

The previous RC serving APS, Peak Reliability, announced that it was winding down operations at the end of 2019. After assessing all options, APS has chosen RC West as its new RC. RC West began operations on July 1, 2019 for California and northern Mexico entities. APS and many other utilities in the western region successfully transitioned to RC West on November 1, 2019.

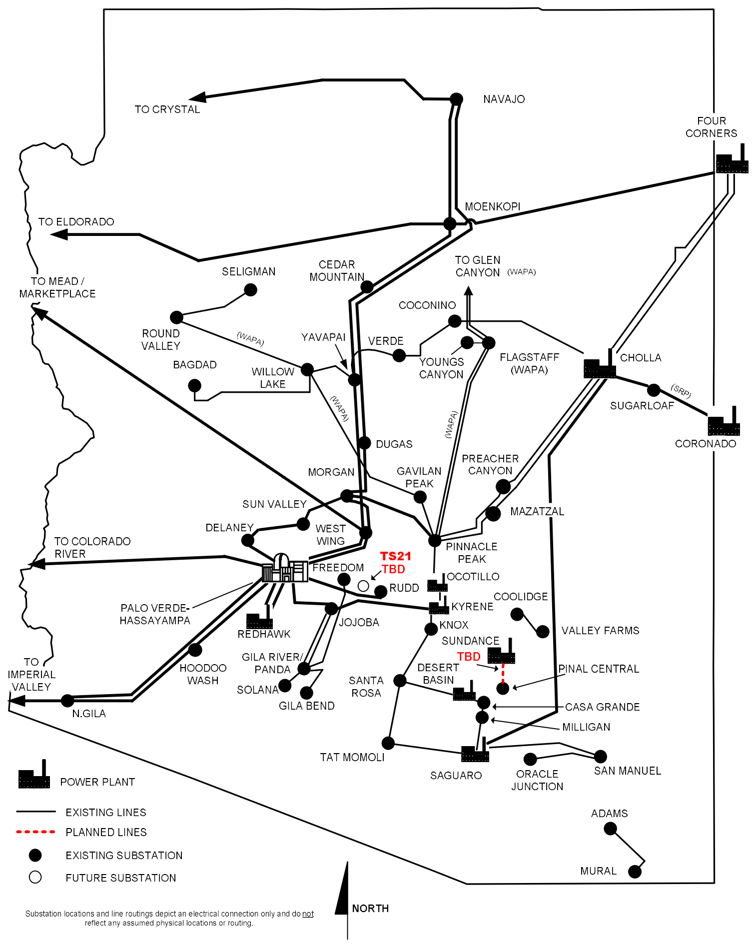
Transmission Planning

APS's electric transmission facilities consist of more than 6,000 miles of high voltage transmission lines, over 29,000 miles of distribution lines, 439 substations, over 300,000 transformers and more than 550,000 power poles and structures.[2] APS owns all or a part of several major transmission paths in the states of Arizona, New Mexico and Nevada which transport electricity from fossil, nuclear and renewable facilities as well as various long-term purchase agreements as shown in Figure 4-1.

Sub-transmission systems carry energy reduced from high voltage transmission lines to ultimately deliver electricity to customers. APS annually conducts an analysis of its 69kV sub-transmission and identifies where modifications may be needed to accommodate changes in load. More specific information related to sub-transmission and distribution resources can be found in Response to Rule D.1 (f).

Distribution systems are the subset of the grid that delivers power to customers. APS focuses its distribution system planning efforts on a five-year basis due to the challenges associated with accurately forecasting the level and location of load growth beyond that timeframe.

FIGURE 4-1. APS EXTRA HIGH VOLTAGE TRANSMISSION SYSTEM



Optimizing use of the existing transmission system is crucial to the resource planning process as it manages costs, increases line efficiency and is the first step to new generation siting initiatives. As adequate transmission must either exist or be planned for construction in support of future generation resources, as well as potential contingencies, APS's Resource Planning and Transmission Planning departments coordinate to ensure continued reliability of service. Additionally, new transmission strategies are continuously reviewed to enhance the use of the existing system and improve reliability. Moving to the use of the Flowgate methodology (MOD-030) of calculating short-term transfer capabilities is one area APS is pursuing to unlock short-term efficiencies and greater transmission commerce through the APS system for its native customers, neighboring utilities and independent developers.

[2] See APS Witness Jacob Tetlow's Direct Testimony, ACC Docket Nos. E-01345A-16-0036 and E-01345A-16-0123.

MOD-030

APS recently announced (posting available on the APS OASIS website) that it will use a new methodology for transmission system utilization. The Company will transition from a Rated System Path Methodology (MOD-029) to a Flowgate Methodology (MOD-030) for the calculation of Available Transfer Capability (ATC). This transition process will take approximately two years to complete, will result in more efficient use of and unlock capacities for the Company's transmission system and may also provide more flexibility in siting generation resources.

MOD-030 is a different way of calculating and tracking transmission capacity and will enable a more efficient utilization of APS's transmission system. MOD-030 establishes Flowgates, or "zones", to manage transfer capability across the entire system, in contrast to the individual point-to-point transmission segments established in MOD-029. This will allow APS to look at the transmission system holistically, delivering a wide range of benefits. Available Transmission Capacity Studies can be conducted on a much more frequent basis, hourly in MOD-030 compared to annually in MOD-029, in order to depict real-time conditions more accurately on APS's transmission system. This will allow APS to provide transmission service more optimally to its customers and utilize the transmission system by increasing realized available transmission capacity in real-time.

LOCAL TRANSMISSION PLANNING PROCESS

APS's Transmission Plan, filed annually, identifies and evaluates future electric transmission system additions that may be required to serve the anticipated APS area load growth, associated generation additions, and/or to accommodate interconnection requests. Figures 4-2 and 4-3 provide an overview of the major projects detailed in the APS Transmission Plan. In the formulation of its Transmission Plan, APS uses the reliability criteria established by the Western Electricity Coordinating Council (WECC) and NERC, in addition to select APS criteria, to ensure plan compliance. Also, included with the Transmission Plan are the Renewable Transmission Action Plan and the technical study on the effects of DG/EE on the transmission system in the fifth planning year pursuant to ACC decision,[3] and are also included in attachments B and C. For the 2020-2029 planning cycle, the Transmission Plan did not show any additional need for Renewable Transmission Projects (RTP) beyond what was approved by the Commission in the previous order. Two of the three RTPs have been completed, with no currently identified need to progress on the third plan. Results of the DG/EE Study indicate that DG and EE additions have minimal effect on APS's Bulk Electric System (BES) as currently planned in 2024.

FIGURE 4-2. PHOENIX METROPOLITAN AREA TRANSMISSION PLANS (2020-2029)

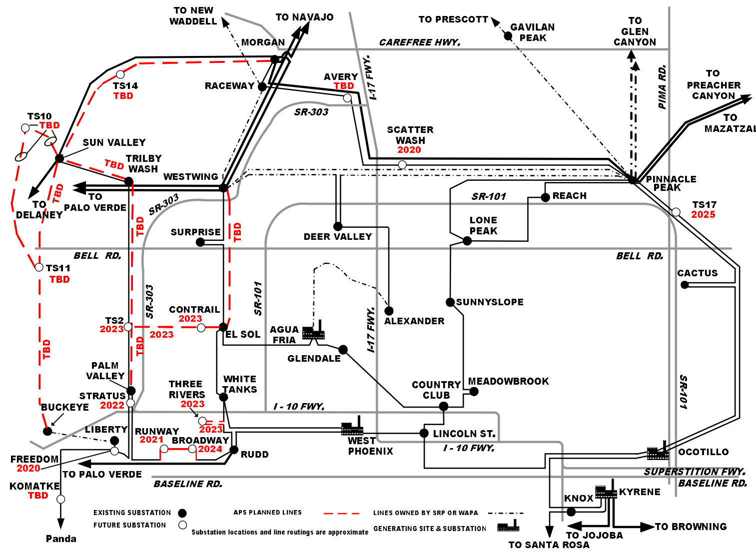
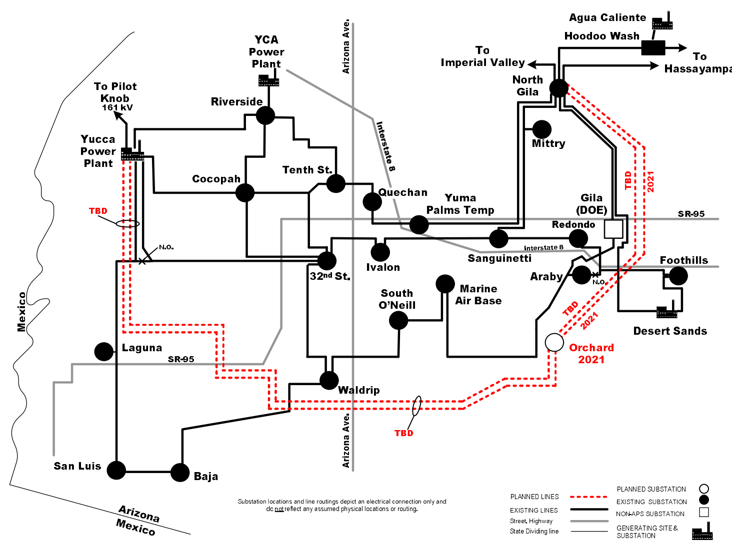


FIGURE 4-3. YUMA AREA TRANSMISSION PLAN (2020-2029)



[3] ACC Decisions 70635 (Dec. 11, 2008) and 74785 (Oct. 24, 2014) respectively.

REGIONAL TRANSMISSION PLANNING PROCESS

APS participates in numerous regional planning organizations in recognition that transmission planning has broad implications over the entire WECC region. Through membership and active engagement in these organizations, the needs of multiple entities, as well as the region, can be identified and studied, which maximizes the effectiveness and use of new projects. APS is a member of the following regional organizations which coordinate transmission and generation additions and retirements:

Western Electricity Coordinating Council (WECC)

WECC is a FERC-designated regional entity for the Western Interconnection and has delegated authority from NERC to create, monitor and enforce reliability standards.

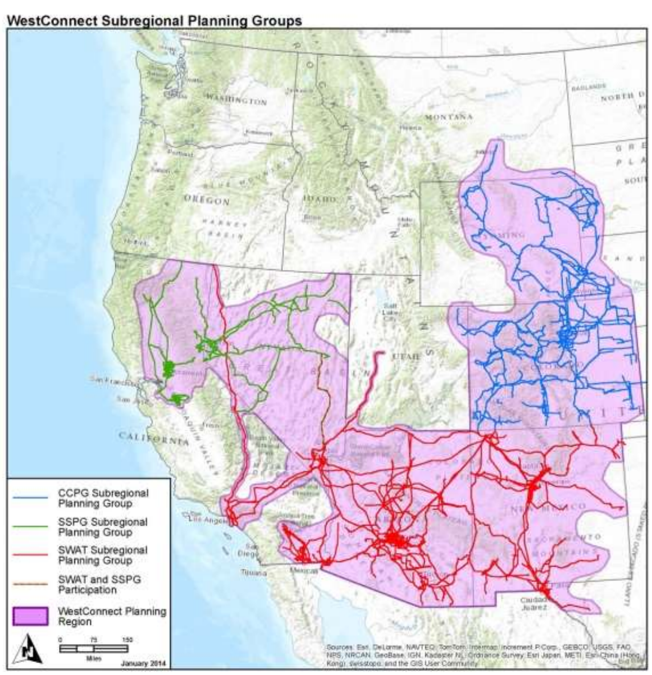
WestConnect – FERC Order 1000 Compliance

WestConnect is composed of transmission owners (TO) and various other parties that are signatories to the participation agreement in regional transmission planning activities for FERC Order 1000 compliance (see map on Figure 4-4 for the WestConnect footprint). This includes participation in a regional transmission planning process that satisfies the principles outlined in FERC Order 1000 and results in a regional transmission plan. The goal of the WestConnect planning forum is to coordinate transmission planning among multiple TOs and various stakeholders in both an intra- and inter-regional manner with the intention of identifying more efficient or cost-effective solutions to identify reliability, economic, public policy needs or any combination of such needs.

Southwest Area Transmission (SWAT)

SWAT is a group of transmission regulators, transmission users, transmission owners, transmission operators and environmental entities that work collaboratively to encourage implementation of a robust transmission system in the southwestern United States (see map on Figure 4-4 for the SWAT footprint).

FIGURE 4-4. WESTCONNECT PLANNING REGION



Source: WestConnect, Regional Planning, Subregional Planning Groups, http://regplanning.westconnect.com/subregional_plng_groups.htm

To Learn More

Arizona Corporation Commission
https://azcc.gov

Biennial Transmission Assessment (BTA)
https://azcc.gov/utilities/electric/biennial-transmission-assessment

Open Access Same-Time Information System (OASIS)
http://www.oasis.oati.com/azps/index.html

Federal Energy Regulatory Commission (FERC)
https://www.ferc.gov

North American Electric Reliability Corporation (NERC)
http://www.nerc.com/Pages/default.aspx

Western Electricity Coordinating Council (WECC)
https://www.wecc.biz/Pages/home.aspx

Southwest Area Transmission
http://regplanning.westconnect.com/swat.htm

WestConnect
http://www.westconnect.com

Northern Tier Transmission Group (NTTG)
http://www.nttg.biz/site/index.php?option=com_docman&view=list&Itemid=31

California ISO
http://www.caiso.com/

CHAPTER 5

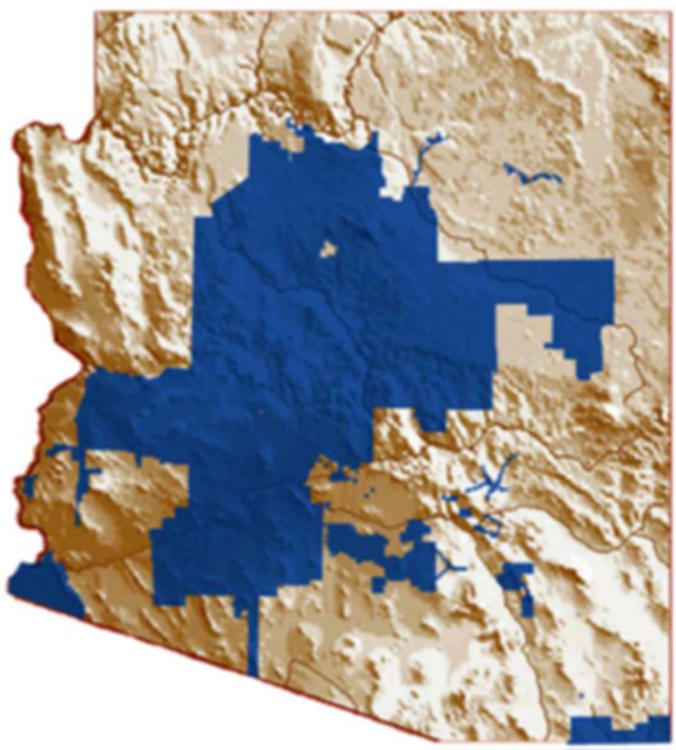
LOAD FORECAST

LOAD FORECAST

Recently, Arizona has experienced a set of challenging circumstances with the COVID-19 pandemic. The pandemic has had impacts on APS customers, the state and the national economy that are yet to be fully understood. The Company's focus has been on maintaining the electric system and keeping customers' lights on in these uncertain times. While the IRP does not reflect any impact of the pandemic, APS plans to keep the Commission, customers and stakeholders informed with any new information as its effects are better understood. APS's view is constantly evolving and as major assumptions for reasons such as data center additions, new DSM programs or economic conditions are updated, the Company will keep the IRP participants informed. Over the long term, the fundamentals of the Arizona economy remain strong, and APS is committed to meeting our clean energy goals.

APS is the largest and longest-serving electric public service company in the state of Arizona with operations reaching back nearly 135 years. Today, APS provides electricity to 1.3 million customers in 11 of Arizona's 15 counties through a diverse energy portfolio of over 10,000 MW, including purchased power agreements and customer-based resources, and transmission and distribution lines covering more than 35,000 miles.

FIGURE 5-1. APS SERVICE TERRITORY MAP



The Company's focus on providing 100% clean, carbon-free and affordable energy requires a view into the future that allows lead time to construct and adapt its existing electric system to meet future customer needs. The APS load forecast provides a basis for resource additions into the future, both supply and demand side resources. The forecast is long-term in nature, however the most important period to consider is the near-term view as it will guide decisions that must be made over the Action Plan window, 2020-2024. The longer-term forecast is important to develop a longer-term strategy and directional resource targets, but those items have the benefit of being updated over time and in subsequent IRPs when outer years become near-term and actionable.

APS projects that annual peak demand and energy needs will increase at compounded annual growth rates of 2.1% and 2.7%, respectively, during the IRP Planning Period of 2020-2035 which is inclusive of distributed generation and DSM/energy efficiency (EE). The growth over the Planning Period equates to approximately 2,600 MW of capacity needs or nearly 175 MW annually, on average. Energy needs are also expected to grow 15,300 GWh, but the transformation of customers' usage and resource mix will change significantly over the same period. For the Action Plan window, APS expects peak load to grow by nearly 550 MW which will require new resources additions that are evaluated in subsequent chapters of the IRP.

Projected growth in the APS service territory is driven by four major factors: population growth, economic growth, data center growth and changing customer trends related to DSM, electric vehicles (EVs) and distributed generation. Those variables are a result of favorable attributes such as the climate, statewide amenities, a positive business environment, technological focused development and a relatively low cost of living.

Load Forecast Update and Evaluation

Forecasting load is a foundational component of an integrated resource plan, fundamental to analyzing not only how many resources the Company needs and when, but to an increasing degree, the type of resources needed. Weather, population growth, economic activity and energy consumption patterns all play a role in determining future energy demand, and each is subject to variability, producing actual results that may vary from original projections. Also important is evaluating how those variables interact over the course of both the near-term (Action Plan window) and a 15-year period. Although future unknowns cannot be removed from the forecasting process, APS's robust forecasting methodologies are structured to address uncertainty over the Planning Period.

As part of the APS approach to its 2020 IRP forecast and as a result of the APS stakeholder process, the Company retained Itron, an industry consulting group with expertise in load forecasting, to review existing forecasting practices. Itron worked with the forecasting group at APS and provided feedback on forecasting technique and model reasonableness relative to other forecasts in the utility industry. The conclusions were:

- Methods are consistent with industry practices and produce reasonable results given the input assumptions.
- Modelling approaches for residential customers, commercial and industrial (C&I) usage, data centers and peak demand are reasonable.
- Recommend APS revisit the residential average use modelling assumptions to remove inconsistencies among the model components.

Itron further noted that the residential forecast was within the range of reasonable outcomes, despite the modelling inconsistencies; however, based on the Itron recommendation, the residential average use forecast has been updated to reflect an improved approach to residential average usage. The residential average usage forecast is now derived from the results of a multiple linear regression model, which estimates the historical relationship between residential electricity usage and the following key drivers: cooling, heating, home size, the real price of electricity and real personal income per capita for Arizona. This statistical modeling approach is common in the industry and resolves the concerns identified by Itron in the prior modeling approach.

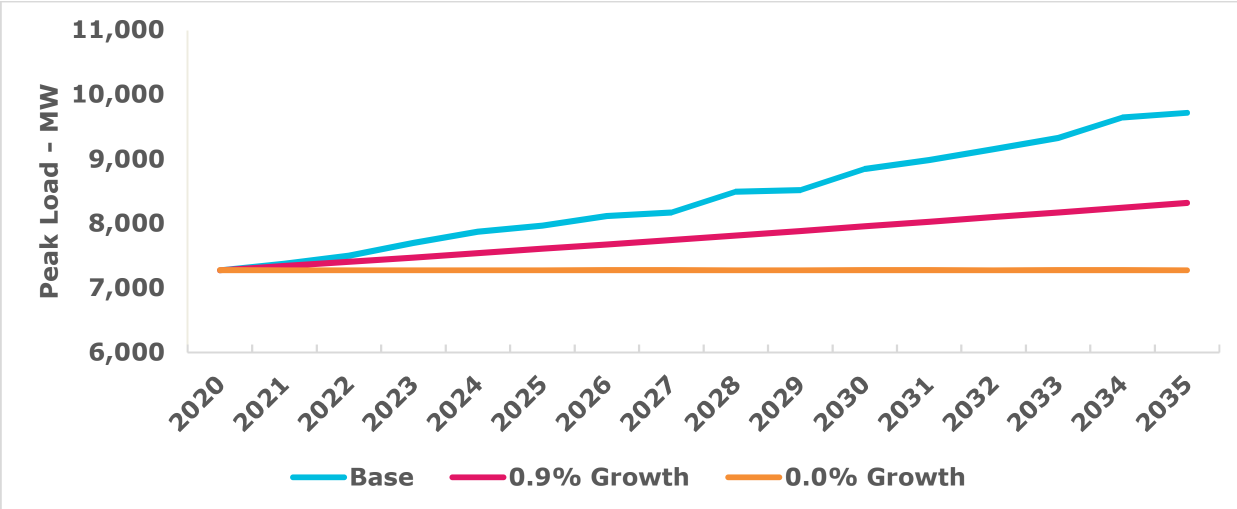
Additionally, APS worked with stakeholders to review the inclusion and representation of DSM in the load forecast. And while APS continues to work toward a final approach to DSM through the IRP process, agreement on counting and inclusion of programs has led APS and participants to a better understanding of evaluating and presenting the results of our investments in energy efficiency, demand response and reverse demand response or beneficial load building.

LOAD GROWTH FORECAST

Future resource requirements are calculated based on a peak consumption hour growth rate under three scenarios – a base assumption, a forecast growth rate of 0.9% and no growth or 0%,[1] and are shown below (Figure 5-2). The Base Assumption is that peak load growth, after customer resources including energy efficiency and distributed energy, is expected to average approximately 2.1% annually over the next 15 years and result in a peak load increase of about 2,400 MW or 160 MW annually. Under a 0.9% load forecast, peak demand growth averages approximately 70 MW annually or approximately a 1,000 MW increase over the Planning Period. Finally, zero growth does not require any additional resources related to peak load growth.

[1] Required under ACC Decision No. 76632.

FIGURE 5-2. LOAD SENSITIVITIES



FORECAST ENERGY DRIVERS

ENERGY GROWTH SUMMARY

Population and economic growth, and the resulting increase in residential customers and C&I floor space, are the main drivers of energy growth in the near-term; however, energy growth will include new data center load growth and the addition of EVs over time. Average residential usage is expected to decrease slightly, which is driven by home product efficiencies and the impacts of DG and DSM programs; additionally, residential usage includes the reduction related to RCP or rooftop solar purchases. Overall, total residential energy is expected to grow because the positive impact of customer growth outweighs the expected decline in average residential usage. Similarly, C&I is expected to see a reduction in intensity for existing customers, but new customer additions are expected to drive energy requirements. A further discussion of the main components driving energy growth are developed below.

TABLE 5-1. SOURCES OF ENERGY GROWTH

COMPONENT	GWH
New Data Centers	5,537
Residential	3,986
C&I	4,449
Electric Vehicles	1,279
TOTAL GROWTH	**15,251**

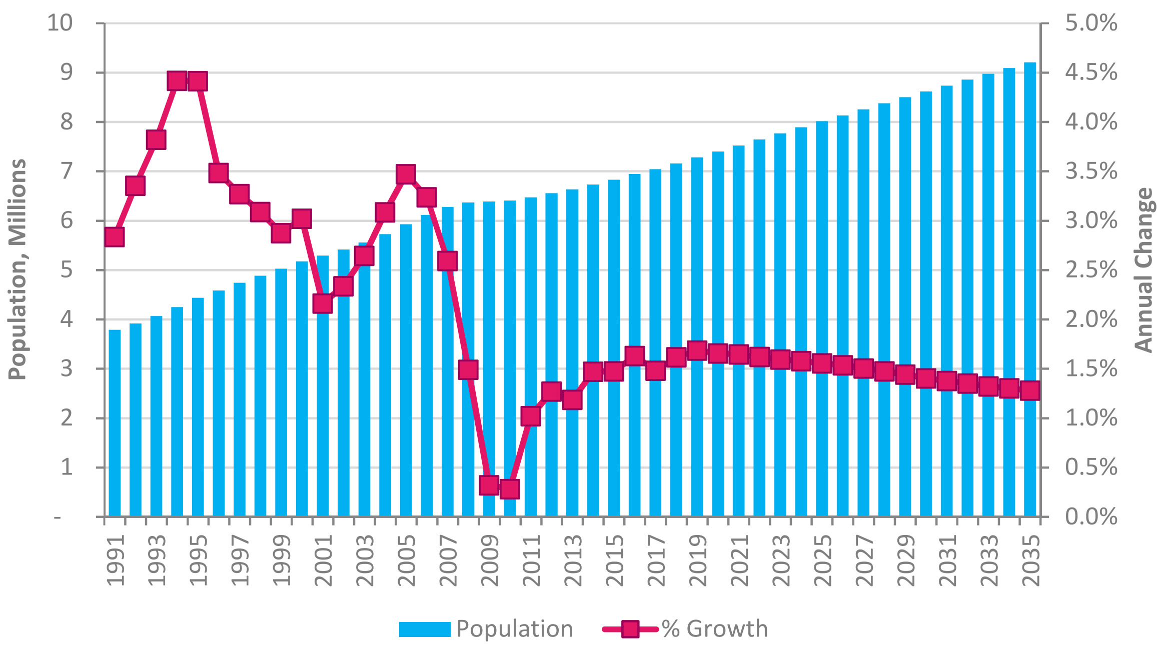
POPULATION AND ECONOMIC ACTIVITY

Growth in residential customers and C&I floor space are key drivers of peak and energy needs through the Planning Period. These two categories account for nearly two-thirds of total expected energy growth over the Planning Period and are largely reflective of the climate and positive business environment in Arizona.

Population growth is the most influential variable in developing the APS load forecast, providing the basis for several other forecast components such as growth in households and residential customers. Population growth is also a key driver of increased economic activity in the state and the APS service territory.

Prior to 2008, Arizona experienced strong population growth, driven by high migration rates. Population growth slowed during the recession but has steadily risen since 2011 due to a return to higher levels of migration. We project that migration will remain on average near the current level through the Planning Period, resulting in an average annual population growth rate of 1.5%. While the projected growth is slightly faster than the last decade, APS does not expect that population growth will return to levels seen prior to the Great Recession (Figure 5-3). Although the IRP forecast does not include the uncertain impacts of COVID-19, economic projections suggest that a decline in population growth may occur during 2020-2021, followed by a snapback to higher levels of growth that partly offset the slowdown due to COVID-19; thus, there may not be any effect on the average annual population growth rate for the 2020-2035 Planning Period, but annual numbers may vary. In other words, the dramatic slowdown of population growth that characterized the years following the recession of 2007-2009 is not expected to occur.

FIGURE 5-3. ARIZONA POPULATION GROWTH, 2020-2035



As a result of the population growth and higher levels of economic activity, the Company expects to add about 20,000-22,000 residential customers annually in the near-term. For the 2020-2035 Planning Period, APS anticipates adding 340,000 residential customers (1.7% annual growth, on average).

The business environment in Arizona continues to attract new industry and expand the current customer base. The state's focus on encouraging technology and economic development as well as proximity to large population centers have created a number of opportunities for Arizona to prosper. APS has recently announced several new manufacturing and warehousing additions to its customer base in addition to increasing office space required for new businesses. These drivers lead to projected needs for an additional 270 million square feet of C&I floor space (2.0% annual growth, on average) in the APS service territory.

DEMAND SIDE MANAGEMENT

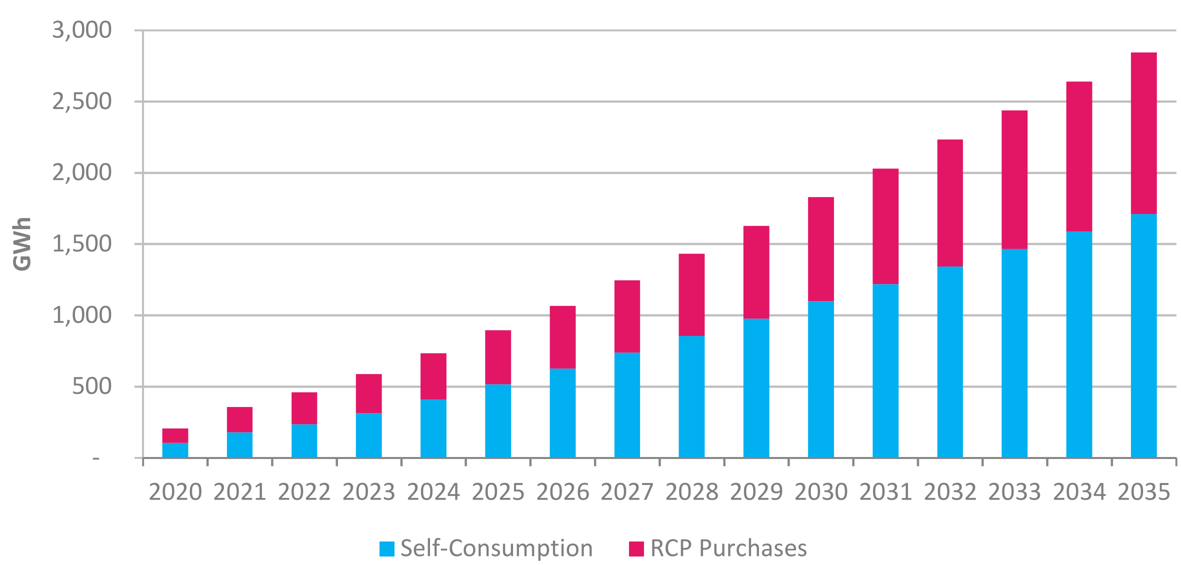
Customers are increasingly interested in managing their own energy consumption, whether passively or actively. In 2018, APS collaborated with a group of stakeholders to push its DSM program further. The 2020 DSM filing reflected this effort and increases investment into measures such as energy efficiency, load shifting and education. The focus is simple: help customers save money while contributing to a cleaner system. By focusing efforts to reduce customer consumption over peak hours when the system's carbon intensity and market prices are highest and encouraging usage when solar generation is producing large amounts of low-priced energy, the Company can reduce carbon emissions as well save customer's money.

As APS looks toward the future, this effort will include electrification of technology that will help transition customers to clean periods of the day to further reduce carbon emissions. By decreasing evening peak consumption and focusing energy consumption when the system is the cleanest, this helps the Company provide a cleaner system for all customers. We believe through continued collaboration with our stakeholders we can maximize benefits for our customers with this approach. The effort with stakeholders started in 2018 continues through progress being made with Guidehouse. Together we are developing a tool to optimize DSM programs with our load. As we move forward, we are excited to see DSM expand at APS and with our customers.

DISTRIBUTED GENERATION/ROOFTOP SOLAR

Installation of private rooftop solar is expected to continue at a strong pace in our service territory. Nationally, APS ranks behind only the three California investor-owned utilities for most cumulative residential solar capacity installed and is one of the few utilities that has added more than 100 MW of residential solar energy for each of the past three years.[2] APS expects the pace of DG installations to average more than 100 MW of capacity added annually.

FIGURE 5-4. ADDITIONAL SOLAR PRODUCTION



[2] 2019 SEPA Utility Solar Market Snapshot (June 2019).

Figure 5-4 shows projected rooftop solar production, broken into self-consumption and Resource Comparison Proxy (RCP) purchases for future distributed solar additions. RCP purchases are comprised of energy not used by a distributed solar customer and purchased by APS at a fixed administrative rate defined by the RCP methodology. Self-consumed production and excess generation (RCP purchases) offset future energy needs but have small impacts on APS capacity needs or reliability requirements. Peak savings from additional DG are relatively small and declining, as DG capacity contributions during peak evening hours are low and the APS system peak continues to shift to hours later in the evening.

DATA CENTERS

Large data centers are attracted to the APS service territory because of our competitive rates, customer service, reliability and commitment to an increasingly cleaner energy mix. Data centers are large, high load factor customers that will benefit communities and our existing customers economically and by increasing the APS system load factor. APS believes high load factor customers can increase usage in low priced renewable energy hours thereby increasing renewable utilization while offering the opportunity to more efficiently utilize system generation and manage electric rates.

Several companies are planning data center locations in our service territory, and some sites have either already started taking power or are planning on ramping up their load by late-2020 and beyond. Additional data center locations are currently under construction with load growth expected in 2021. While there is some uncertainty regarding the rate of growth, APS projects annual peak demand and energy needs will grow 640 MW and 5,500 GWh, respectively, due to data center load during the IRP Planning Period of 2020-2035.

ELECTRIC VEHICLES

While EV adoption rates are just beginning to pick up, APS expects the EV market share of new vehicles sold to steadily increase. Expansion of EVs is one component that APS views as an important piece of continuing to improve the environment in Arizona. To assist in an EV development perspective and based on stakeholder feedback in our IRP process, APS retained Navigant Consulting for an EV study on adoption in our service territory and to evaluate some of the infrastructure improvements required to support EV adoption. We have adopted a forecast that projects the addition of over 320,000 EVs during the Planning Period which equates to approximately 170 MW of capacity needs and 1,300 GWh of energy requirements. With the rapid development of EV adoption and ever changing EV legislation we recognize the importance of continuously updating our assumptions. We will continue to work with industry experts to improve our EV forecast as we move forward in this mostly uncharted territory.

LOAD FORECAST RISKS

Population and economic growth are the primary drivers of the forecasted energy growth and therefore pose the greatest uncertainty to the forecast; economic impacts due to events such as COVID-19 create uncertainty in near-term forecasts; however, fundamentals of the Arizona economy are resilient and the long–term outlook remains strong. Additional risks to the forecast include changes in residential usage and C&I intensity. These changes could be driven by several factors: the pace of new DG installations, higher or lower levels of DSM programs which APS is currently working on with stakeholders, or new legislation on building codes or appliance standards. Finally, the pace of ramp-up in new data center load and rate of EV adoption are key drivers of growth that are less certain in the near-term but expected to evolve over the Planning Period.

CHAPTER 6

REGULATORY

FEDERAL AND STATE REGULATIONS

Although APS's operations are governed by a wide range of federal, state and local laws, the regulatory environment from a resource planning perspective is focused on four key areas: planning and standard-setting, environmental, licensing and permitting. Regulation of other issues, such as transmission, are covered in the Company's other regulatory filings.

KEY LEGISLATIVE & REGULATORY AUTHORITIES GOVERNING APS RESOURCE PLANNING ISSUES

U.S. Congress
Passes energy-related legislation from which federal agencies promulgate regulations.

U.S. Environmental Protection Agency (EPA)
Regulates water use and certain emissions of power-generating facilities.

U.S. Nuclear Regulatory Commission (NRC)
Oversees the safety and licensing of nuclear power plants.

Arizona Corporation Commission (ACC)
Sets utility rates, governs resource and transmission planning activities, and sets standards to achieve state-wide energy objectives.

Arizona Department of Environmental Quality (ADEQ)
Administers Arizona's environmental laws and delegated federal programs to prevent air, water and land pollution and ensure cleanup.

Local Air Quality Departments
Issues preconstruction and operating permits.

TABLE 6-1. KEY REGULATORY & PERMITTING REQUIREMENTS

RULES & STANDARDS

ARIZONA CORPORATION COMMISSION

- Integrated Resource Planning (IRP) Rules
- Ten-Year Transmission System Plan
- Certificate of Environmental Compatibility
- Renewable Energy Standard
- Energy Efficiency Standard

ENVIRONMENTAL LEGISLATION

U.S. CONGRESS

- Clean Air Act (CAA)
- Clean Water Act (CWA)
- Resource Conservation & Recovery Act (RCRA)
- Toxic Substances Control Act (TSCA)
- Comprehensive Environmental Response Compensation & Liability Act (CERCLA)

ENVIRONMENTAL REGULATION

U.S. ENVIRONMENTAL PROTECTION AGENCY

- Regional Haze Program
- Air Toxics Program
- National Ambient Air Quality Standards
- Carbon Pollution Standards for Fossil-Fired Electric Generating Units
- Cooling Water Intake Structure Regulations
- Revised Effluent Limitation Guidelines
- Coal Combustion Residual Regulations

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

- Arizona laws and delegated federal programs governing air quality, water quality, groundwater protection, and waste programs

FEDERAL

- National Environmental Policy Act Review
- Endangered Species Act Consultation and Permitting
- CWA Section 404 Permitting
- CWA National Pollutant Discharge Elimination System
- Right-of-Way for Use of Tribal Lands
- NRC Nuclear Generation Licensing Process
- New Source Review and Prevention of Significant Deterioration

STATE

- Certificate of Environmental Compatibility
- Delegated Clean Air Act Permitting
- Arizona Pollutant Discharge Elimination System Permits (CWA Delegated)
- Aquifer Protection Permit
- CAA preconstruction and Title V air quality operating permits

LOCAL

- Maricopa County Air Quality Department – CAA preconstruction and Title V operating permits for facilities located in Maricopa County
- Pinal County Air Quality Control Department – CAA preconstruction and Title V operating permits for facilities located in Pinal County

Arizona Corporation Commission

INTEGRATED RESOURCE PLANNING

The current Arizona Corporation Commission's (ACC or Commission) IRP Rules[1] require regulated electric utilities to file an IRP detailing how customer needs are projected to be met over a 15-year period. The IRP Rules require load-serving entities in Arizona, including APS, to submit to the Commission the following filings:

Historical Filing (every year by April 1)

The Historical Filing details demand- and supply-side data for the previous calendar year, except for coincident peak demand and number of customers by customer class, which are reported for the previous ten (10) years.

Work Plan (every odd numbered year by April 1)

The Work Plan outlines the contents of the upcoming IRP.

Integrated Resource Plan (every even numbered year by April 1)

The IRP details how a load-serving entity intends to meet peak load over a 15-year Planning Period and includes:

- A coincident peak load and energy consumption forecast for each month and year
- A comparison of a wide set of resource options, taking into consideration fuel and technology diversity
- The selection of a portfolio based on a wide range of considerations of demand- and supply-side options
- Documentation of assumptions, models and methods used in forecasting
- Analysis of the integration costs of renewables
- Expected reductions in environmental impacts
- Comprehensive risk assessments of the IRP components
- A 3-Year Action Plan

In Decision No. 76632 (March 29, 2018), the Commission adopted an alternative schedule for Arizona's regulated electric utilities to prepare and file their respective 2020 IRPs. Based on this ACC decision, APS was originally required to file its next IRP by April 1, 2020. On February 26, 2020[2], the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020 to June 26, 2020.

In Decision No. 75068 (May 8, 2015), the Commission ordered Arizona's load-serving entities, with the exception of Arizona Electric Power Cooperative, to file updates to the 3-Year Action Plans contained in their respective IRPs whenever a substantive change occurs in the near-term resource plan.

[1] A.A.C. R14-2-703.
[2] ACC Decision No. 77574, dated February 26, 2020.

Decision No. 76632 (March 29, 2018) included several supplemental requirements for APS and TEP to incorporate into Final IRPs, including:

- Portfolio analyses with forecasted changes in costs for both established and emerging technologies
- Independent third-party analysis of the scenarios and portfolios
- Detailed discussion of natural gas storage from both a market development and gas cost perspective
- Sensitivity analysis with a wide range of gas price scenarios
- Portfolio analysis with a storage alternative as a resource option and consider storage alternative when considering new generation capacity, or upgrades to existing generation, transmission, and distribution systems
- Scenarios with both no load growth and low growth under one percent (1%)
- At least one portfolio where the addition of fossil fuel resources is no more than twenty percent (20%) of all the resource additions. To develop this portfolio, work with stakeholders – specifically any Tribal Nations in Arizona – that desire to participate in developing the portfolio to satisfy this requirement
- At least one portfolio with a fifteen-year forecast of the lesser of 1000 MW of energy storage capacity or an amount of energy storage capacity equivalent to twenty percent (20%) of system demand; at least fifty percent (50%) clean energy resources (including 25 MW of biomass); and at least twenty percent (20%) of demand side management
- No purchases, acquisitions or construction of a natural gas facility of 150 MWs or more, subject to specific exceptions and Commission approval. In Decision No. 77512 (December 17, 2019), the Commission required APS to provide all relevant Qualified Facility (QF) data every three years as part of its IRP. The data should include the number of QF contracts entered into to date, nameplate capacity for each interconnected QF and the avoided cost rate for each interconnected QF. APS is currently in discussions with QF counterparties to develop projects in Arizona and will notify the Commission of executed contracts and project specifics on an ongoing basis.

TEN-YEAR TRANSMISSION SYSTEM PLAN

In compliance with A.R.S. § 40-360.02, the ACC requires Arizona regulated electric utilities to file an annual Ten-Year Transmission System Plan (Ten-Year Plan) for major transmission facilities. Arizona regulated electric utilities are also required to file a Renewable Transmission Action Plan in accordance with ACC Decision No. 70635 (December 11, 2008), a Technical Study on the Effects of DG/EE on Fifth Year Transmission in accordance with ACC Decision No. 74785 (October 24, 2014) and internal planning criteria and system ratings in accordance with ACC Decision No. 63876 (July 25, 2001).

Commission Staff reviews utility Ten-Year Plans every two years as part of the Commission's Biennial Transmission Assessment (BTA). The BTA assesses the adequacy of Arizona's transmission system to reliably meet existing and future energy needs of the state and reviews regional transmission planning issues. Staff conducts a review of the utilities' transmission enhancements and additions, solutions for transmission import constraints where any may exist in various load pockets, and local transmission system mitigation measures where needed.

ACC STANDARDS

Renewable Energy and Energy Efficiency Standards

The ACC Renewable Energy Standard (RES)[3] requires fifteen percent (15%) of retail sales be met by renewable energy by 2025. As part of the RES, APS must also meet a portion of the renewable energy requirement with distributed energy resources. The ACC Energy Efficiency Standard (EES)[4] requires a twenty-two percent (22%) cumulative energy savings requirement by 2020.

RENEWABLE ENERGY STANDARD

The ACC's RES requires electric utilities under its jurisdiction to supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. The renewable energy requirement is ten percent (10%) of retail electric sales in 2020 and increases annually until it reaches fifteen percent (15%) in 2025. The RES also includes a carve-out for distributed energy systems of thirty percent (30%) of the overall RES requirement per year.

Table 6-2. RES % REQUIREMENTS

YEAR	RES REQUIREMENT[5]
2020	10%
2021	11%
2022	12%
2023	13%
2024	14%
2025	15%

ENERGY EFFICIENCY STANDARD

The ACC's Energy Efficiency (EE) rules went into effect in 2010 and increase yearly up to an EES of twenty-two percent (22%) of cumulative annual energy savings by 2020. The requirement is a percent of prior year's retail sales. The rules sunset at year-end 2020.

Table 6-3. EES % REQUIREMENTS

YEAR	EES REQUIREMENT[6]
2020	22%

ACC RULEMAKINGS

The Commission has two separate rulemakings underway that may impact the development of utility IRPs in future years. In 2018, the Commission began discussions to revise the current energy rules and modernize the Commission's approach to a wide range of energy issues. In November 2018, the Commission also voted to re-examine the facilitation of a deregulated retail electric market in Arizona.

ENERGY MODERNIZATION PLAN

The Commission opened a rulemaking docket[7] in August 2018 to address a wide range of energy issues, including possible modifications to existing ACC energy rules such as the RES and EES, net metering, resource planning and the biennial transmission assessment. Discussions and workshops were held throughout 2019, and several draft rule proposals were issued. The most recent set of draft rules developed by Staff proposes a RES standard of forty-five (45%) of retail energy to be served by renewable resources by 2035, and a standard of twenty (20%) of retail sales during peak demand to be from clean energy resources, also by 2035. Nuclear energy would be considered clean energy under the draft rules. The draft rules also propose changing the IRP planning horizon from 15-years to 10-years. Discussions regarding these draft rules are expected to continue during 2020.

RETAIL COMPETITION

In 2018, the Commission opened a separate docket[8] to gather information and discuss implementation of retail electric competition in the State of Arizona for its jurisdictional utilities. Stakeholders and other interested parties have provided comments and participated in workshops discussing direct access in other states, the impact of retail competition and choice on all classes of customers, reliability, and resource planning in a competitive environment. Commission Staff has issued reports regarding possible modification to the current ACC retail competition rules. Several draft rules have been issued, each differing in significant areas including eligibility of customer classes and requirements for providers of last resort. Discussions on retail competition and whether it is in the public interest are expected to continue during 2020.

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[3] A.A.C. R14-2-1801 et seq.
[4] A.A.C. R14-2-2401 et seq.
[5] The requirement is calculated each calendar year by applying the applicable annual percentage to the retail kWh sold. *See* A.A.C. R14-2-1804(B).
[6] The requirement is a percent of prior year's retail sales. *See* A.A.C. R14-2-2404(B).
[7] Docket No. RU-00000A-18-0284
[8] Docket No. RU-00000A-18-0405

Environmental Legislation

U.S. CONGRESS

There have been no recent successful efforts by the U.S. Congress to pass legislation that materially changes federal environmental statutes. With respect to the 116th Congress, it remains unclear at this time what environmental legislation, if any, will be proposed for consideration and passage. Substantial changes to federal environmental statutes through congressional action by the current U.S. Congress are not expected at this time.

Environmental Regulations

Environmental regulations are promulgated on the federal (EPA), state (ADEQ), and county (Maricopa, Pinal, and Pima) levels.[9] The EPA, specifically, has promulgated multiple regulations that have an impact on APS's operations.

CLEAN AIR ACT

The CAA regulates air emissions from stationary and mobile sources. Numerous programs have been established to protect public health and welfare by controlling emissions of air pollutants.

REGIONAL HAZE (VISIBILITY)

The Four Corners and Cholla power plants are subject to the CAA's Regional Haze rule, which required an analysis of the impacts of air emissions from certain industrial facilities and the installation of "Best Available Retrofit Technology" (BART) to control emissions from those facilities to improve visibility in affected national parks and wilderness areas. The focus of the regulations is to reduce emissions of oxides of nitrogen (NOx), sulfur dioxide (SO2) and particulate matter (PM), which contribute to visibility impairment in these federal areas. Congress enacted the visibility statutes to address the aesthetic effects of air pollution in national parks and wilderness areas, not to protect public health. To secure "Reasonable Progress" with statutory goals, the Regional Haze rule envisions a long period, covered by several planning phases, to meet the congressionally established national visibility goal targeted to be met in 2064. The State of Arizona is required to develop a Regional Haze State Implementation Plan (SIP) for each period, the first of which extended from 2005 through 2018. Each subsequent planning period will run for ten (10) years.

Arizona's first Regional Haze SIP covered the initial planning period extending from 2005 through 2018 and included a BART determination for each BART-eligible source in the state. APS's Four Corners and Navajo plants were subject to BART determinations made by the EPA, as these facilities are located on the Navajo Nation. Final regulations imposing BART requirements have now been imposed on each APS coal-fired power plant. Four Corners was required to install new pollution controls to comply with BART, while similar pollution control installation requirements were not necessary for Cholla.

During the next (i.e., second) planning period, which will run from 2019 through 2028, the State of Arizona must consider man-made sources of visibility-impairing pollutants for potential Reasonable Progress controls. Reasonable Progress controls will be assessed through a four-factor analysis that includes:

- the cost of control
- the time necessary to install controls
- energy and non-air quality impacts
- remaining useful life

All sources of air pollution could potentially be subject to additional emission control requirements in the second and subsequent planning periods of the Regional Haze program. State plans that will demonstrate continued progress toward the goal of natural visibility conditions will not be submitted until July 31, 2021. The Arizona Department of Environmental Quality (ADEQ) hosted several stakeholder meetings regarding its Regional Haze plan development

[9] Additional information regarding environmental regulations can be found in Response to Rule D.17.

and APS engaged with ADEQ to better understand how the process could impact its facilities. At this time, APS cannot predict the final results of this process.

MERCURY AND AIR TOXICS STANDARD (MATS)

The EPA proposed a rule regulating hazardous air pollutants (HAPs) on May 3, 2011 and finalized the regulations on December 16, 2011. The rule establishes standards and requirements for reducing mercury and other HAP emissions from certain electric generating units. APS met all of its regulatory obligations for installing activated carbon injection on Units 1, 3 and 4 at Cholla. Four Corners Units 4 and 5 met the mercury limit with existing equipment. Both facilities are fully compliant with the applicable emissions limitations.

On March 13, 2020, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued an opinion remanding to the EPA for reconsideration of elements of the 2014 rule addressing startup and shutdown periods under this rule. At this time, APS cannot predict the outcome of this process.

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

To protect public health and welfare, the CAA established NAAQS for six (6) pollutants: ozone, NOx, SO2, PM10, carbon monoxide, and lead. In 2008, the EPA adopted a new ozone NAAQS and set it at 75-parts per billion (ppb). On July 20, 2012, the EPA designated the geographic area containing the Phoenix Metropolitan area as marginal non-attainment for ozone. After failing to meet the attainment deadline of July 20, 2015, the EPA downgraded the Phoenix area's designation to moderate non-attainment for ozone. On June 13, 2019, the EPA proposed to find that the Phoenix ozone non-attainment area had met the requirement to achieve compliance with the 2008 ozone standard by July 20, 2018. After taking public comment, the EPA finalized the decision on November 12, 2019. The EPA's decision alleviated the requirement for the development and implementation of attainment contingency measures for ozone, but did not suspend the CAA's attainment-related requirements, including the provision to install Reasonably Available Control Technology at major sources of air pollution, like the APS West Phoenix facility. Also, the area was not redesignated as attainment for the standard and will remain as a moderate non-attainment area until such time as the EPA determines that the area has met the criteria for redesignation.

On January 9, 2020, the Arizona Center for Law in the Public Interest filed a petition for review of the EPA's November 12, 2019 final action. At this time APS cannot predict the final results of the court process.

On October 26, 2015, the EPA adopted another new ozone NAAQS and set it at 70-ppb. On April 30, 2018, the EPA designated the geographic areas containing Yuma and Phoenix, Arizona as in non-attainment with the 2015 70-ppb ozone NAAQS. The vast majority of APS's natural gas-fired Electric Generating Units (EGUs) are located in these jurisdictions. Areas of Arizona and the Navajo Nation where the remainder of APS's fossil-fuel fired EGU fleet is located were designated as in attainment. With ozone standards becoming more stringent, APS's fossil generation units will come under increasing pressure to reduce emissions of NOx and volatile organic compounds, and to generate emission offsets for new and modified sources of air pollution, including new and modified generating sources, in the ozone non-attainment areas.

APS anticipates that revisions to the SIPs and Federal Implementation Plans (FIPs) implementing required controls to achieve the new 70-ppb standard will be in place between 2023 and 2024. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

CARBON POLLUTION STANDARDS FOR FOSSIL-FIRED ELECTRIC GENERATING UNITS

In 2009, the EPA determined that greenhouse gas (GHG) emissions endanger public health and welfare. As a result of this "endangerment finding," the EPA determined that the CAA required new regulatory requirements for new and modified major GHG emitting sources, including power plants. APS will generally be required to consider the impact of GHG emissions as part of its traditional New Source Review (NSR) analysis for new major sources and major modifications to existing plants.

On June 19, 2019, the EPA took final action on its proposals to repeal EPA's 2015 Clean Power Plan (CPP) and replace those regulations with a new rule, the Affordable Clean Energy (ACE) regulations. The EPA originally finalized the CPP on August 3, 2015, and those regulations had been stayed pending judicial review.

The ACE regulations are based on measures that can be implemented to improve the heat rate of steam-electric power plants, specifically coal-fired EGUs. In contrast with the CPP, EPA's ACE regulations would not involve utility-level generation dispatch shifting away from coal-fired generation and toward renewable energy resources and natural gas-fired combined cycle power plants. EPA's ACE regulations provide states and EPA regions (e.g., the Navajo Nation) with three (3) years to develop plans establishing source specific standards of performance based upon application of the ACE rule's heat-rate improvement emission guidelines. While corresponding NSR reform regulations were proposed as part of the EPA's initial ACE proposal, the finalized ACE regulations did not include such reform measures. The EPA announced that it will be taking final action on the EPA's NSR reform proposal for EGUs soon.

The Company cannot at this time predict the outcome of the EPA's regulatory actions repealing and replacing the CPP. Various state governments, industry organizations, and environmental and public-health public interest groups have filed lawsuits in the D.C. Circuit challenging the legality of the EPA's actions in repealing the CPP and issuing the ACE regulations. In addition, to the extent that the ACE regulations go into effect as finalized, it is not yet clear how the State of Arizona or the EPA will implement these regulations as applied to APS's coal-fired EGUs. Given these uncertainties, APS is still evaluating the impact of the ACE regulations on its coal-fired generation fleet.

CLEAN WATER ACT

The CWA establishes the basic structure for regulating discharges of pollutants into waters of the United States and regulating quality standards for surface waters. Under the CWA, the EPA has implemented pollution control programs, such as setting wastewater standards for industry and water quality standards for all contaminants in surface waters.

COOLING WATER INTAKE STRUCTURES

The EPA issued its final cooling water intake structures rule on August 15, 2014, which provides national standards applicable to certain cooling water intake structures at existing power plants and other facilities pursuant to Section 316(b) of the CWA. The rule is intended to protect fish and other aquatic organisms by minimizing impingement mortality (the capture of aquatic wildlife on intake structures or against screens) and entrainment mortality (the capture of fish or shellfish in water flow entering and passing through intake structures). These standards are intended to comply with Section 316(b)'s standard that such cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

EFFLUENT LIMITATION GUIDELINES (ELG)

On September 30, 2015, the EPA finalized its revisions to the ELG establishing technology-based wastewater discharge limitations for fossil fuel-fired EGUs. The final regulation is intended to reduce metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and leached wastewaters collected from coal ash disposal units. Based on an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, "zero-discharge" from fly ash and bottom ash handling, and impoundments for leached wastewaters collected from coal ash disposal units. Compliance with these limitations will be required as a part of the National Pollution Discharge Elimination System (NPDES) permit renewals, which arise over the course of five-year intervals.

On August 11, 2017, the EPA announced that it would be initiating rulemaking proceedings to potentially revise the September 2015 ELG. On September 18, 2017, EPA finalized a regulation postponing the earliest date on which compliance with the ELG for these waste streams would be required from November 1, 2018 until November 1, 2020. In addition, on November 22, 2019, the EPA published a proposed rule relaxing the "zero discharge" limitations for bottom ash handling water and allowing for approximately ten percent (10%) of such wastewater to be discharged (on a volumetric, 30-day rolling average basis) subject to best-professional judgment effluent limits. The Company cannot predict the outcome of this rulemaking proceeding. Nonetheless, it is expected that compliance with the resulting limitations will be required in connection with NPDES discharge permit renewals at Four Corners. For the current NPDES permit issued to Four Corners, which is subject to an appeal by various environmental groups, the plant must comply with the existing "zero discharge" ELG for bottom ash transport wastewater by December 31,

2023. If those guidelines are changed, it is unclear when Four Corners would need to demonstrate compliance with any updated or revised standards. NPDES permitting is not required for Cholla power plant.

On November 1, 2019, several environmental groups filed a petition for review before the EPA Environmental Appeals Board (EAB) concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on September 30, 2019. The environmental groups allege that the permit was reissued in contravention of several requirements under the CWA and did not adequately contain stringent provisions concerning the EPA's 2015 revised ELG for steam-electric EGUs,2014 existing-source regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal ash disposal facilities. The environmental groups also contest the jurisdictional status of certain cooling-water storage facilities associated with Four Corners. The Company cannot predict the outcome of this review and whether the review will have a material impact on its financial position, results of operations or cash flows.

RESOURCE CONSERVATION AND RECOVERY ACT

The Resource Conservation and Recovery Act (RCRA) gives the EPA the authority to control hazardous waste from "cradle-to-grave." RCRA also regulates the management of non-hazardous solid wastes, such as coal combustion residual wastes (CCR), as well as underground tanks storing petroleum and other hazardous substances.

COAL COMBUSTION RESIDUALS

On December 19, 2014, the EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the RCRA and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post-closure care, and record keeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close. It further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, the EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

- Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, the EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, it is not clear when that program will be put into effect. On December 19, 2019, the EPA proposed its own set of regulations governing the issuance of CCR management permits.

- On March 1, 2018, as a result of a settlement with certain environmental groups, the EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019 to add a specific, health-based groundwater protection standard for boron, EPA has yet to act on this proposal.

- Based on an August 21, 2018 D.C. Circuit decision which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, the EPA recently proposed corresponding changes to federal CCR regulations. On November 4, 2019, the EPA proposed that all unlined CCR surface impoundments, regardless of their impact (or lack thereof) on surrounding groundwater, must cease operation and initiate closure by August 31, 2020 (with an optional three-month extension as needed for the completion of alternative disposal capacity).

- On November 4, 2019, the EPA proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's proposal regarding alternative closure would require express EPA authorization for such facilities to continue operating CCR disposal units under alternative closure.

The Company cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action.

As of October 2018, APS completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must cease operating and initiate closure by October 31, 2020. APS initiated an assessment of corrective measures on January 14, 2019 and expects such assessment will continue through mid- to late-2020. As part of this assessment, APS continues to gather additional groundwater data and perform remedial evaluations as to the CCR disposal units at Cholla and Four Corners undergoing corrective action. In addition, APS will solicit input from the public, host public hearings, and select remedies as part of this process.

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

ADEQ is Arizona's primary environmental regulatory agency, with responsibility for developing and enforcing state regulations that implement Arizona environmental laws, and for helping ensure that businesses and regulated sources operate according to federal and state environmental laws and regulations. Three programmatic divisions – Air Quality, Water Quality, and Waste Programs, carry out ADEQ's core responsibilities. In some areas, Arizona's environmental laws go beyond the federal laws. Examples include the Arizona State Hazardous Air Pollutants Program and the Arizona Aquifer Protection Permit Program.

Similar to the EPA delegation authority, ADEQ may delegate some permitting and enforcement responsibilities to counties within the state.

ENVIRONMENTAL PERMITTING FOR NEW CONSTRUCTION

Construction of new electric facilities, whether for electric generation or for transmission, requires compliance with extensive permitting and environmental impact review processes. Depending on the specifications of the facility and its location, the permitting and review process may take twenty-four (24) months or more to complete before construction is authorized. The major permits and environmental review obligations required by federal, state and local authorities are described below.

FEDERAL

NATIONAL ENVIRONMENTAL POLICY ACT REVIEW

The National Environmental Policy Act (NEPA) requires federal agencies to prepare an Environmental Impact Statement (EIS) on proposals for major federal actions (including authorizations or approvals) significantly affecting the quality of the human environment. The EIS describes the environmental impacts of a proposed action and alternative actions that may be taken instead of the one proposed. An EIS may be required when a development is proposed for a site on undisturbed, environmentally sensitive or federally-protected land, or for projects subject to federal funding or approval. For those projects that are not expected to result in significant environmental impacts, federal decision or action agencies are authorized to prepare an Environmental Assessment (EA) along with a Finding of No Significant Impact (FONSI). An EA/FONSI is typically a more concise document than an EIS and requires significantly less environmental review to complete.

ENDANGERED SPECIES ACT CONSULTATION AND PERMITTING

With respect to projects that may result in harm to species federally-designated as threatened or endangered, compliance with the species impact review procedures under the federal Endangered Species Act (ESA) is required. For projects with a federal nexus, such as those involving land under federal jurisdiction or federal funding or authorizations, the federal action or decision agency must consult with the U.S. Fish and Wildlife Service under Section 7 of the ESA, which can result in certain species protection conditions being placed on federal acts of discretionary authority. As for those projects without a federal nexus, Section 9 of the ESA provides for incidental "take" permitting, which authorizes purely private activity that may otherwise harm protected species subject to certain species protection conditions.

CLEAN WATER ACT SECTION 404 PERMITTING

For projects that cross or otherwise result in the discharge of dredge or fill material within certain surface water resources under federal jurisdiction (or "Waters of the U.S."), permitting under Section 404 of the CWA from the U.S. Army Corps of Engineers is required. The current scope and extent of what qualifies as a surface water resource under federal jurisdiction is subject to controversy and dispute, including recent regulations issued on January 23, 2020, and is likely subject to further litigation.

RIGHT-OF-WAY FOR USE OF PUBLIC LANDS

When constructing generation facilities or installing transmission lines on tribal lands, within national forests or parks, or on other federally-designated public lands (i.e., under the jurisdiction of the federal Department of the Interior or Department of Agriculture), a right-of-way, permit or other special-use authorization is required. For development within tribal reservation land, including trust lands, approval must be sought from the governing tribe and the U.S. Bureau of Indian Affairs. These types of approval often require NEPA review and ESA consultation.

NRC NUCLEAR GENERATION LICENSING PROCESS

Despite the recent increase in federal support for nuclear power projects, including loan guarantees and the NRC improved licensing process, the period from design to commissioning is double that for other technologies while costs are considerably higher. New nuclear generator units often have a lead time of over nine (9) years because: (1) new reactor licenses must be approved by the NRC, which can take between two and a half to five years, and (2) after the review process is complete, construction can take roughly five to eight additional years.[10]

STATE

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Utilities, with proposed power plants or transmission lines subject to the jurisdiction of the ACC and the Arizona Power Plant and Line Siting Committee (Committee), are required to make an application with the ACC for a Certificate of Environmental Compatibility (CEC).[11] During public evidentiary hearings, the Committee considers the application relative to a series of factors[12] including, among other things, the status of all applicable permits. Following these deliberations, the Committee makes a recommendation to the Commission regarding the CEC. The ACC then makes a final determination on the CEC application complying with A.R.S. § 40-360.06 and balancing, in the public interest, the need for an adequate, economical, and reliable supply of electric power with minimizing environmental impact.[13]

DELEGATED CLEAN AIR ACT PERMITTING

The State of Arizona has approval to implement the federal CAA preconstruction permit program and is the local permitting authority for all of Arizona, except Maricopa County, Pima County, Pinal County, and tribal lands. The EPA administers this program for sources on tribal lands, where the tribe does not have its own approved program or has agreed not to exert regulatory jurisdiction over a source. The CAA preconstruction permits, commonly known as "Prevention of Significant Deterioration" (PSD) permits in geographical locations that meet or exceed the National Ambient Air Quality Standards (NAAQS) and as "Nonattainment New Source Review" (NNSR) permits in locations that fail to meet the NAAQS, must be obtained and effective prior to beginning construction of a new major source of air emissions, and prior to making a major modification to an existing source of air emissions.

[10] International Atomic Energy Agency, Nuclear Power - Small and Medium Sized Reactors (SMRs) Development, Assessment and Deployment, available at https://www.iaea.org/NuclearPower/SMR/.
[11] Applies to construction of a new thermal electric, nuclear, or hydroelectric facility of 100 MW or more or a transmission lines of 115kV or greater.
[12] Specified in A.R.S. § 40-360.06.
[13] A.R.S. § 40-360.07.

PSD and NNSR permits are legally binding air quality permits that include enforceable emission limitations with which the emission source owner/operator must comply. These emission limitations are known as “Best Available Control Technology” (BACT) for attainment areas and as “Lowest Achievable Emission Rate” (LAER) for nonattainment areas. These limits are then rolled into the eventual Title V air quality permits referenced below.

TITLE V AIR QUALITY PERMIT

The State of Arizona has approval to implement the federal Title V operating permit program, established by the 1990 federal Clean Air Act Amendments. Three of the 15 counties within the state, Maricopa, Pima and Pinal, have also received approval to implement the federal Title V operating permit program. The remaining 12 counties remain under ADEQ jurisdiction. The EPA administers the Title V operating permit program on tribal lands when the tribe does not have its own approved program or has agreed not to exert regulatory jurisdiction over a source. Title V permits must be obtained and effective for all major stationary sources of air emissions. Title V permits are legally binding air quality permits that include enforceable conditions with which the emission-source owner/operator must comply. The permit conditions establish limits on the types and amounts of air pollution allowed, operating requirements for pollution control devices or pollution prevention activities, and monitoring and record-keeping requirements.

AQUIFER PROTECTION PERMIT

ADEQ also issues Aquifer Protection Permits (APPs) to power plants that have regulated facilities, such as impoundments, that have the potential to impact aquifer water quality. Power plants have monitoring programs that include collection of water quality samples from monitoring wells that are located down gradient of regulated facilities. These sample results are reported to ADEQ on frequencies established in the APP and provide evidence that aquifer water quality standards are met.

LOCAL

MARICOPA COUNTY AIR QUALITY DEPARTMENT (MCAQD)

MCAQD issues CAA preconstruction and Title V operating permits for facilities located within Maricopa County, which include APS’s Redhawk, West Phoenix, and Ocotillo power plants. As with ADEQ, MCAQD requires a Title V permit for any major stationary source of air emissions. MCAQD also requires a CAA preconstruction permit for any new major source of air emissions or for major modifications to existing sources of air emissions.

OTHER LOCAL AGENCIES

APS’s natural gas-fired Saguaro and Sundance power plants are located in Pinal County. Therefore, these plants are under the jurisdiction of the Pinal County Air Quality Control Department, which issues CAA preconstruction and Title V operating permits for facilities located within Pinal County.

To Learn More

U.S. House of Representatives
http://www.house.gov/

U.S. Senate
https://www.senate.gov/

U.S. Environmental Protection Agency
https://www.epa.gov/

U.S. Nuclear Regulatory Commission
https://www.nrc.gov/

Arizona Corporation Commission
https://www.azcc.gov/

Arizona Department of Environmental Quality
http://www.azdeq.gov/

Maricopa County, Air Quality Department
http://www.maricopa.gov/1244/Air-Quality

Pinal County, Air Quality
http://www.pinalcountyaz.gov/AirQuality/Pages/home.aspx

CHAPTER 7

PORTFOLIO ANALYSIS

PORTFOLIO ANALYSIS

The IRP process culminates in the evaluation and comparison of a number of alternative resource plans to meet future electricity needs associated with system reliability and the Company's renewable goals while putting it on a trajectory to meet the 2050 clean energy goals. This chapter discusses the development and analytical evaluation of alternative resource plans and their associated potential risks. Based upon the needs and opportunities assessment identified in Chapters 1 and 2, a set of portfolios were developed and measured against those future commitments. This chapter includes the major assumptions affecting the resource choices, description of the resource plans, future uncertainties and sensitivities, along with a comprehensive set of results. Consideration is given to many factors to evaluate trade-offs associated with future options to meet customers' long-term needs of reliable, cost-effective and environmentally responsible electricity.

The portfolio analysis recognizes the importance of the Action Plan period as emphasis is placed on decisions the Company must make today to prepare for the future. While the portfolios provide results for the Planning Period of 15 years, many decisions beyond the Action Plan period may be altered or updated as new technologies are introduced and future costs are revised. When building the portfolios that reach the 2035 clean energy goals, the Company recognized that all three plans call for the same resources within the near-term Action Plan window. This is significant because it points to the certainty of the next steps needed to stay on course toward the Company's clean energy commitment goals.

Development of Resource Portfolios

Beginning in late 2018, APS engaged a group of stakeholders, industry experts and researchers in pre-IRP discussions. This was an extensive process in which seven all-day meetings were held over a nine-month period with the group to do a deep dive and allow stakeholders to closely examine, question and provide feedback on the integrated resource planning assumptions and methodologies. Through this process, APS engaged Energy and Environmental Economics, Inc. (E3), a leading energy consulting firm, to perform high-level comparative modeling and economic analysis of a wide range of portfolios proposed by APS and the stakeholders. Results of the evaluations were presented and filed with the Arizona Corporation Commission (ACC or Commission)[1] and are included in Appendix F. These efforts informed the portfolios that have been evaluated in this IRP.

The term "resource portfolio" refers to the entire set of resources over the Planning Period designed to meet customer demand for electric energy. For example, each portfolio is designed to provide a level of reliability to APS customers that is generally equivalent over the Planning Period or meets a 15% reserve margin target annually. All portfolios include the existing generation fleet and power contracts as well as potential future resources (conventional, energy storage, renewable, DSM programs, etc.) to meet customer demands. Portfolio analysis includes dispatch simulations and captures how an individual resource would be expected to operate on the APS system. Revenue requirements were developed for each of the resource portfolios using Energy Exemplar's AURORA production simulation software along with ABB's Strategist software. Together, along with sensitivity analysis, APS can show trade-offs such as cost, carbon production and MW additions associated with different strategies or resource selections in the future.

With feedback and insight from the stakeholder engagement, APS developed four portfolios for the 2020 IRP: Path 1 – Bridge, Path 2 – Shift, Path 3 – Accelerate, and Technology Agnostic. The Accelerate and Technology Agnostic portfolios represent bookends of a wide range of portfolios, while Bridge and Shift represent intermediate portfolios that fill in points along the spectrum. The Technology Agnostic portfolio

[1] Filed with the ACC March 23, 2020 in Docket No. RU-00000A-18-0284.

was developed with resource optimization software that did not impose limits on the amount of new natural gas that could be built. On the other end of the spectrum, the Accelerate portfolio featured accelerated deployment of renewable resources and energy storage systems (ESS). In this accelerated renewable and ESS portfolio, all future resource needs are met with combinations of solar (rooftop and grid-scale), wind, biomass, energy efficiency (EE) and energy storage technologies, and none are met with gas tolling purchased power agreements (PPAs) or new hydrogen-ready natural gas units. The Technology Agnostic portfolio did not meet APS's clean energy commitment and was only used as a base of comparison for the other portfolios. Of the two intermediate portfolios, Bridge was designed to meet the requirements of the clean energy commitment (45% renewables and 65% clean energy resources by 2030), and Shift provides an option between Bridge and Accelerate.

Sensitivity analysis was performed on the three Path portfolios that would enable APS to meet its clean energy commitment. "Sensitivity Analysis" refers to running the portfolios and varying the assumptions related to key uncertain variables. The goal of sensitivity analysis is to illustrate the impact to each portfolio's key variables being stressed in a plausible manner. Results of these studies provide information on fuel diversity, cost, environmental impacts, robustness and overall risk to assist in the selection of a resource plan.

INPUTS AND ASSUMPTIONS

Each of the resource portfolios assessed incorporate the following criteria:

Load Forecast – The load forecast used throughout the following analysis is based on the best available data as of the end of the first quarter 2020, and is described in more detail in response to Rules C.1 through C.3 and E(a). The current load forecast assumes an annual average of approximately 2% peak growth year-over-year for a net 34% increase in load requirements after the effects of EE and distributed energy (DE) at the end of the Planning Period. As previously noted, this forecast does not incorporate impacts of the COVID-19 pandemic.

Distributed Energy - DE (rooftop solar) has grown dramatically over the last few years and is projected to continue to grow at approximately 100 MW per year through 2035. This amounts to nearly 1,600 MW and 2,800 GWh of new DE added in APS service territory between 2020 and 2035. Due to the high penetration of solar energy on the APS system and the misalignment between production and peak demand, solar energy contributes only 225 MW toward meeting the summer peak load. The DE forecast, including existing DE, is provided in response to Rule D5.

Reserves – Resources are installed to maintain at least a 15% reserve margin at the time of APS's summer peak. This level of reserves is discussed in Chapter 2 in more detail.

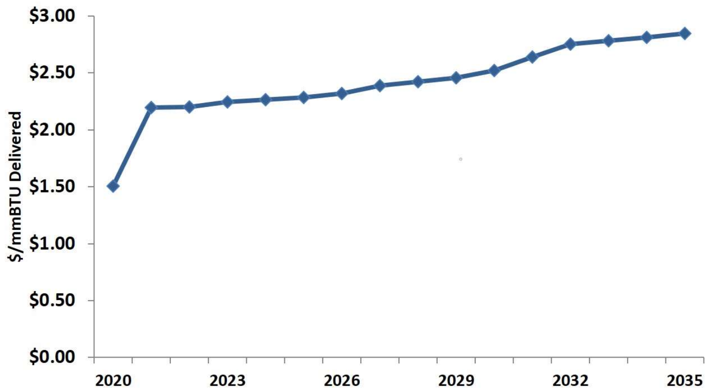
Inflation – APS assumes a future inflation rate of 2.5% per year. Exceptions to this inflation assumption are described in response to Rule D.1(d).

Compliance with Standards – All portfolios developed exceed the state's Energy Efficiency Standard (EES) which ends in 2020 and exceed compliance with the state's Renewable Energy Standard (RES).

Asset Ownership – APS has not determined which assets may be owned by APS or contracted through third-party PPAs. However, for modeling purposes only, existing PPAs remain PPAs and new resources are assumed to be APS owned. This provides for a more straightforward comparison of economic analysis of technologies and resource portfolios that is not clouded by the different cost trajectories of ownership versus PPAs. The actual mix of ownership versus PPAs will be determined as APS executes its clean energy plan over the coming years.

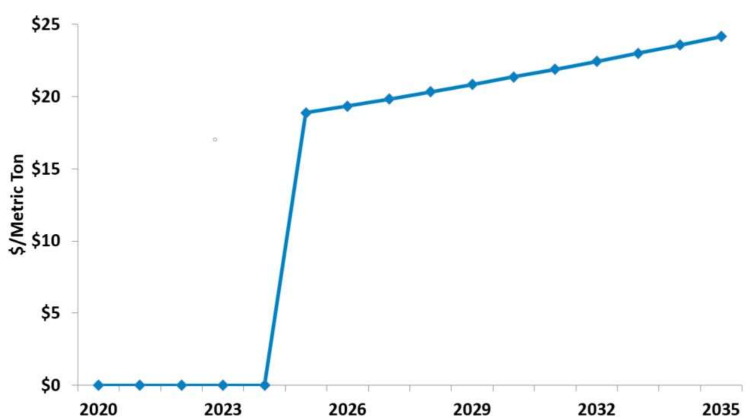
Natural Gas Prices – The natural gas price curve utilized in the base case analyses was derived from an analysis of the forward market price curve for natural gas as of the end of the first quarter 2020 and includes delivery charges. APS currently has sufficient gas pipeline capacity contracted to serve its existing natural gas generators (owned and leased) through 2031. Beyond that, in the event that additional pipeline capacity is needed, it is assumed that additional pipeline capacity would become available in the market or be built and is reflected in the price to deliver natural gas.

FIGURE 7-1. NATURAL GAS PRICE CURVE



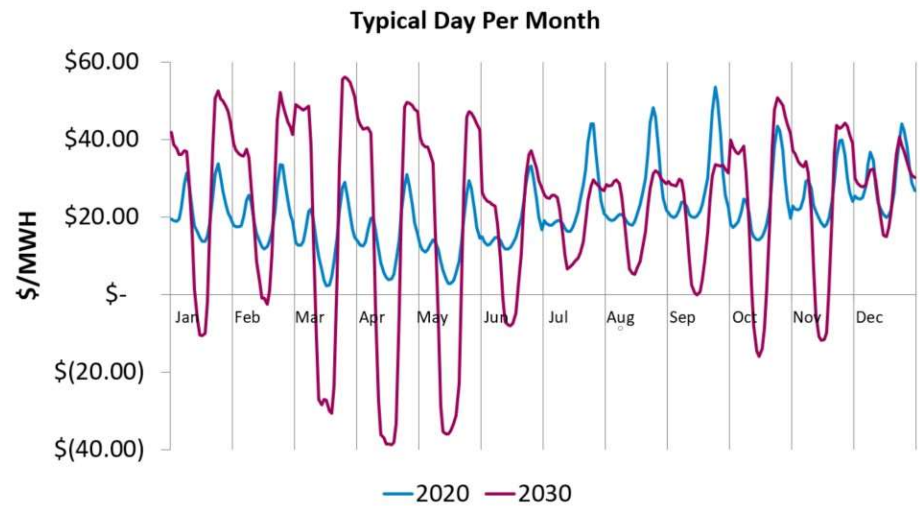
Carbon Costs – APS is incorporating assumed carbon costs based on the actual trading price of CO2 allowances in the California market. The EPA has taken actions to repeal the Clean Power Plan and replace it with the Affordable Clean Energy (ACE) regulations. These actions are under judicial review, and APS cannot predict the outcome. APS believes it is reasonable to evaluate carbon costs in its resource planning at this time, although it is likely to have minimal impact on APS's resource selections because additions are largely driven by clean energy goals rather than strictly centered on cost. The 2020 IRP analysis assumes that carbon legislation occurs at either the state or federal level and carbon prices take effect in 2025, escalating at the assumed rate of inflation.

FIGURE 7-2. CARBON PRICE CURVE



Wholesale Market Prices – Hourly wholesale market prices for the Palo Verde node were developed for APS by E3. The prices, based on regional electric market fundamentals, include the gas price forecast used in this IRP and reflect California's mandate of 60% renewables by 2030. Note that the CAISO is experiencing negatively priced energy with increasing frequency in the midday during non-summer months due to surplus non-curtailable renewable generation in California. The model allows APS to purchase from the wholesale market to offset its own fossil generation or curtail APS-owned solar for the benefit of APS's customers. Rooftop solar is not curtailed, but allowing rooftop curtailment would provide APS customers with additional savings on an APS system basis. Incidences of negative market pricing are expected to increase as California and other neighboring states move toward higher renewable energy mandates.

FIGURE 7-3. PALO VERDE HUB MARKET PRICES



DSM Costs – APS incorporates more than 700,000 MWhs and 260 MW per year of DSM into its resource portfolios which include savings from codes and standards programs, behavioral and educational programs, demand response, energy efficiency, load management and energy storage as indicated in the Company's 2020 DSM plan filing. EE programs and program costs are based on APS's 2020 DSM amended filing with the Commission and are assumed to continue at that pace over the Planning Period. Programs focus on peak load reduction programs and load shifting rather than targeting MWh requirements because peak load reduction and load shifting are most effective at displacing additional supply-side resources and carbon emissions. The cost of the DSM programs, including demand response, is $51.9 million in 2020 and is assumed to escalate at the rate of inflation thereafter. Additional DSM/customer resources (demand response) are included in the portfolios.

Technology Costs – Capital costs of technologies are based on information obtained from vendors, industry publications and evaluation of bids in APS's RFP processes. Costs of established technologies shown in Chapter 2 are assumed to escalate at the rate of inflation while costs of certain technologies such as energy storage and solar are assumed to decline. It is essential to evaluate these resources through detailed annual production simulation models such as AURORA because these models offer comprehensive, annual cost estimates of how new resources integrate with the existing resource mix and meet changing load and reliability requirements rather than on a stand-alone levelized cost basis.

PTC/ITC – APS assumes that the current tax provisions related to production tax credits and investment tax credits expire as detailed in Chapter 2.

KEY METRICS

APS specifically monitored the impacts of a set of key metrics that provide insight into the holistic impact of each set of resource combinations. A high-level summary of these metrics is included below while comprehensive and detailed annual values are included in Attachments F.1(a) and F.1(b) for all portfolios modeled using base assumptions.

Clean Energy – APS's commitment is to provide its customers with 65% clean energy by 2030 and be 100% clean, carbon-free energy by 2050. All portfolios are measured against this commitment. "Clean energy" is defined herein as all non-CO2 energy resources (including existing and new EE savings, grid-scale and distributed renewable energy, nuclear and purchases of excess energy produced from renewable sources) divided by Total Resource Requirement (generation, purchased power, and DSM/EE savings). It is assumed that purchases are produced from excess renewable energy if they are zero or negatively priced, otherwise they assume the carbon emissions of natural gas generation. As discussed below, DSM and renewable measurements are calculated at the sales level under the State's EES and RES rules.

Affordability (Portfolio Costs)[2] – Portfolio costs are measured in terms of net present value (NPV) of revenue requirements over the Planning Period as well as average system generation cost in $/MWh at the end of the Planning Period.[3] Customer affordability is a key component of APS's clean energy commitment.

Reliability – All portfolios are developed to meet APS reliability requirements of 15% planning reserve margin which is expected to result in meeting the industry standard of one outage event in ten years.

Cumulative Capital Expenditures – Cumulative capital expenditures are an indication of how much capital APS or market participants will need to obtain over the Planning Period to execute each portfolio. Capital expenditures cannot be viewed in isolation because in many cases capital expenditures result in lower fuel costs. For example, renewables have relatively high capital costs, but benefit from zero-priced fuel. A reduction to fuel costs may also lower price volatility for customers.

CO2 Emissions – Total emissions of CO2 give an indication of the amount of carbon and environmental risk associated with each portfolio. Tabulation of CO2 emissions is different yet complementary to the clean energy metric.

Fuel Diversity – A more diverse portfolio relies on a greater number of energy sources, mitigating risks associated with any one particular source. Fuel diversity is quantified by the energy mix by the end of the Planning Period (2035).

Renewable Curtailment – Renewable curtailment is quantified for the last year of the Planning Period (2035). As more renewables are added to the system, a certain amount of renewable energy cannot be used by the customers and cannot be stored because the energy storage devices are already full and wholesale market conditions are not supportive. Furthermore, renewable energy may be curtailed in order to make room to purchase negatively priced market energy. In the event that negatively priced energy is not available in the market, APS's renewable resources will be curtailed less.

Water Use – Water use is another important factor in analyzing portfolios and is quantified in terms of acre-feet per year.

Natural Gas Usage – Natural gas usage provides an indication of the amount of natural gas cost risk inherent in each portfolio.

Market Purchases – Market purchases of regional carbon free energy are key elements of providing a cost-effective way for APS to meet its clean energy commitment. Utilizing excess carbon free energy from the market allows APS to improve upon its economics and can benefit customers through lowering the overall cost of providing energy.

Renewable, Clean Energy and Energy Mix Calculations – APS uses two types of metrics to report the relative shares of different types of generation in its portfolio; these each serve a specific purpose.

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[2] Portfolio costs represent the total costs of the resource additions from generation and related incremental transmission needed to deliver that generation perspective. While it may be indicative of the increasing costs that will develop into future rates, these costs are not inclusive of all rate components (e.g., distribution costs, other transmission costs, metering/billing costs, etc.).

[3] Average system generation cost, represented in $/MWh, is not intended to directly equate to customer rates; rather, it is indicative of the per-unit cost of energy from APS generation resources as outlined in each portfolio, and does not include other components of customer rates such as distribution system costs.

To report the renewable energy share, the accounting conventions specified in the existing Arizona RES are used, under which each utility's share of renewables is expressed as a percentage of its retail sales,[4] relative to total sales to customers. As indicated above, APS also reports the share of each type of resource as a share of its total energy mix, including DSM. By including DSM in the energy mix, we are able to show its contribution to the total portfolio. This metric provides a more holistic presentation of the portfolio and treats all resources equally; this metric is used as the primary convention to report the share of clean energy in the portfolio.

These two metrics differ in two respects: retail sales do not include generation losses, and the energy mix is explicitly adjusted to include the load impact of DSM programs. One implication of the differences between these methods is that the Company's portfolios meet the 45% renewable goal by 2030 according to the state's RES accounting conventions, but the reported share of renewables in the energy mix will appear lower. The table below provides an illustrative example for why this result occurs.

TABLE 7-1 – RENEWABLE ENERGY REQUIREMENT AND CLEAN ENERGY MIX EXAMPLE

Energy Requirements (GWh)	40,000
Losses	7%
Retail Sales (GWh)	37,383
Renewable Requirement (% of retail sales)	45%
Renewable Requirement (GWh)	16,822
DSM Load Impact (GWh)	10,000
Energy Requirements – Including DSM (GWh)	50,000
Renewable Share of Energy Mix (% of energy requirements including DSM)	34%

Portfolios

Three portfolios were developed to support the Company's efforts to achieve its clean energy commitment and were based on Commission requirements and insights gained from stakeholder meetings. They all include significant amounts of customer resources such as EE, demand response and microgrids as well as varying levels of grid-scale renewable additions and energy storage deployment. A fourth portfolio is included for reference as a more traditional "least cost" technology agnostic portfolio based on technology costs and performance as seen today by APS and was developed by running ABB's Strategist resource optimization software. This portfolio would not allow the Company to meet its clean energy commitment and carries significantly more gas availability and price risk than the others, and so it was not carried into the sensitivity analysis phase of the IRP.

All four of the portfolios have a few common elements. First, they all meet APS's commitment to exit coal generation by 2031 by assuming retirement of Cholla 1 and 3 in 2024, followed by retirement of Four Corners 4 and 5 in 2031. The Cholla retirement timing is driven by an agreement with the EPA (described in the State and Federal Regulation chapter of the IRP) and Four Corners retirement timing is driven by the expiration of the coal supply agreement. Second, although the Commission's EES ends in 2020, all four portfolios continue to implement peak focused EE at levels similar to that achieved in recent years. Finally, they all include the assumption that customers will continue installation of DE resources at a pace consistent with recent trends.

[4] This approach to accounting for renewable generation is the same as the methods used in neighboring states for RPS accounting.

PATH 1 - BRIDGE PORTFOLIO

The Bridge portfolio was designed to meet the clean energy commitment goals of 45% renewable and 65% clean by 2030. Extending the trend to the end of the Planning Period required a total of (including existing) 9,830 MW of renewable resources (grid-scale solar, wind and DE) and 4,852 MW of energy storage. Some of the peak load capacity/reliability requirements are met with demand response and microgrids. It also allows for some natural gas to be a bridge between now and a future where technology is sufficiently developed to meet the long-term goals by extending gas-based tolling agreements and building a nominal amount of hydrogen-capable combustion turbines. The Loads & Resources table for this portfolio can be found in Attachment F.1(a)(1).

PATH 2 - SHIFT PORTFOLIO

The Shift portfolio shifts more of the emphasis to renewables generation, 11,330 MW by 2035. In order to maximize use of the renewables and manage the amount of curtailed/dumped renewable energy, 6,502 MW of energy storage is also needed. As in the first portfolio, demand response and microgrid customer resources are used to meet peak load capacity/reliability requirements. Also, as in the Bridge portfolio, the extension of gas-based tolling agreements is allowed, but there are no new-build hydrogen-ready combustion turbines included in this portfolio. Shift used 1,500 MW renewables, 1,650 MW energy storage and 50 MW of DR to replace 724 MW of hydrogen-ready combustion turbines in the Bridge portfolio. The Loads & Resources table for this portfolio can be found in Attachment F.1(a)(2).

PATH 3 - ACCELERATE PORTFOLIO

The Accelerate portfolio further increases and accelerates additional renewables to 13,755 MW in 2035, and energy storage technology to 10,552 MW. In this portfolio, all future resources in the Planning Period are carbon free. Therefore, gas-based tolling agreements are not renewed and there are no new build hydrogen-ready combustion turbines. Note that 2,425 MW of renewables, and 4,050 MW of energy storage technology are required to replace 1,135 MW of tolling agreements and 125 MW microgrids represented in the Shift portfolio. The Loads & Resources table for this portfolio can be found in Attachment F.1(a)(3).

TECHNOLOGY AGNOSTIC PORTFOLIO

The three Path portfolios were created with a preference for renewable energy and complementary energy storage technology. The Technology Agnostic portfolio, however, was created to provide a more traditional "least cost" view of the IRP. Although current projections of natural gas prices are low by historical standards, gas-based technology is mature and relatively inexpensive, this portfolio carries significantly more gas supply and price risk than the first three portfolios. Note that this hypothetical plan does not help APS meet its clean energy commitment and thus is not executable. Therefore, this portfolio should be viewed with care, and APS notes that it is not carried into the sensitivity portion of the IRP.

Commission Decision No. 76632 required us to evaluate the following portfolios:

- **Analyze at least one portfolio**
  - **Fossil fuel** resources are **no more than 20%** of all the resource additions

- **Analyze at least one portfolio**
  - **1,000 MW energy storage** capacity
  - At least **50% of clean energy resources**, including at least **25 MW of biomass** running at no less than 60% capacity factor
  - At least **20% Demand Side Management (DSM)**

The following table indicates how the four portfolios meet these requirements.

TABLE 7-2. HOW PORTFOLIOS MEET COMMISSION REQUIREMENTS

	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO	TECHNOLOGY AGNOSTIC PORTFOLIO
Fossil Fuel ≤ 20%	☑	☑	☑	
≥ 1,000 MW Energy Storage	☑	☑	☑	
≥ 50% Clean Energy Resources	☑	☑	☑	☑
≥ 25 MW Biomass			☑	
≥ 20% DSM	☑	☑	☑	☑

The following discussion is broken into two parts –the five-year Action Plan window 2020-2024 and the remainder of the Planning Period (2025-2035). Bridge, Shift and Accelerate portfolios have the same additions during the first five years with the exception of Accelerate, which includes 25 MW of biomass generation. The portfolios diverge in the next ten years as they vary the amount and speed of renewable and energy storage additions.

ACTION PLAN PERIOD (2020-2024)

The three Path portfolios developed to meet the clean energy commitment may present viable paths forward toward meeting APS's objectives of clean, reliable and affordable energy. The five-year Action Plan window is the same for all three plans and supports achievement of the longer-term clean energy targets. The five-year Action Plan sets us on the right path. Immediate actions are identified for 2020-2024 that include rapid additions of renewable energy, demand response, energy efficiency and energy storage to make progress on those commitments. Table 7-3 summarizes the resource additions that set APS on a path to meet its 2030 commitment as well as the long-term goal of providing 100% clean, carbon-free electricity. Figure 7-4 and Table 7-4 indicate the impact these additions have on the Company's energy mix over the five-year period.

TABLE 7-3. 2020-2024 ADDITIONS

2020-2024 ADDITIONS	MW
Demand Side Management	575
Demand Response	193
Distributed Energy	408
Renewable Energy[5]	962
Energy Storage	750
Microgrid	6
Total	**2,894**

[5] The Accelerate portfolio includes 25 MW of biomass, which is not included in the Bridge and Shift portfolio.

FIGURE 7-4. 2020 & 2024 – ENERGY MIX

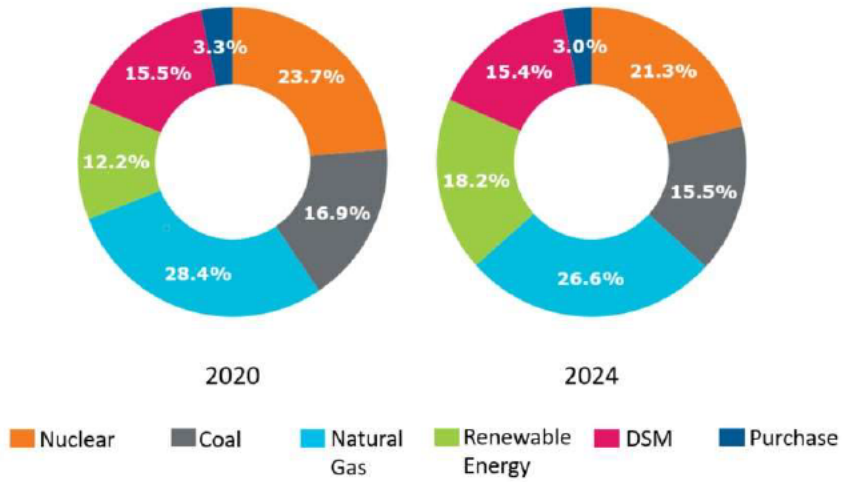


TABLE 7-4. CAPACITY AND ENERGY MIX (2024)

	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO	TECHNOLOGY AGNOSTIC PORTFOLIO
Description	Retire coal by 2031; demand reducing DSM; RE and ESS to meet CEC, gas bridge - extend gas tolling PPAs and add new gas generation	Retire coal by 2031; demand reducing DSM; shift to more RE and ESS, extend gas tolling PPAs and no new gas generation	Retire coal by 2031; demand reducing DSM; accelerate RE and ESS, no gas tolling PPAs and no new gas generation	Retire coal by 2031; demand reducing DSM; limited RE and ESS, extend gas tolling PPAs, new gas generation not constrained
Resource Contributions (2024 Nameplate Capacity/% Energy Mix)				
Clean Energy	55%	55%	55%	51%
RES Achieved	25%	25%	25%	20%
Nuclear	1,146 MW / 21.3%	1,146 MW / 21.3%	1,146 MW / 21.3%	1,146 MW / 21.3%
Coal	1,357 MW / 15.5%	1,357 MW / 15.5%	1,357 MW / 15.5%	1,357 MW / 15.5%
Natural Gas	5,179 MW / 26.6%	5,179 MW / 26.6%	5,179 MW / 26.2%	5,541 MW / 30.3%
Renewable Energy (RE & DE)	3,286 MW / 18.2%	3,286 MW / 18.2%	3,311 MW / 18.5%	2,774 MW / 14.6%
Demand Side Management	575 MW / 15.4%	575 MW / 15.4%	575 MW / 15.4%	575 MW / 15.4%
Demand Response[6]	253 MW	253 MW	253 MW	253 MW
Microgrids[6]	38 MW	38 MW	38 MW	38 MW
Energy Storage[7]	752 MW	752 MW	752 MW	552 MW
Market Purchase[8]	160 MW / 3.0%	160 MW / 3.1%	160 MW / 3.1%	160 MW / 3.0%

[6] DR and microgrids are considered capacity resources and are not included in the energy mix.
[7] Energy storage does not create its own energy, so energy associated with it is reported under the source that provided the charging energy.
[8] Market Purchase capacity (MW) reflects firm power acquired through PPAs, while Market Purchase energy mix % includes firm purchases plus non-firm market wholesale purchases.

REMAINDER OF PLANNING PERIOD (2025-2035)

Over the remainder of the Planning Period, 2025 and beyond, the Company will meet its renewable energy targets, remove all coal from the generation portfolio, and evaluate new resource options that show trade-offs between future resource additions. The three portfolios developed for this IRP vary in their pace of renewable and energy storage resource additions as described below. All portfolios provide carbon reductions in line with levels required to achieve the carbon-free target by 2050. Trade-offs between affordability and carbon reductions are discussed in the Portfolio Results section later in this chapter based on today's projections of costs. Table 7-5 shows the 2025-2035 additions used to evaluate the remainder of the Planning Period.

TABLE 7-5. RESOURCE ADDITIONS: FUTURE RESOURCES (2025-2035)

2025-2035 ADDITIONS (MW)	PATH 1 BRDIGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO	TECHNOLOGY AGNOSTIC PORTFOLIO
Demand Side Management	1,027	1,027	1,027	1,027
Demand Response	500	550	600	500
Distributed Energy	1,177	1,177	1,177	1,177
Renewable Energy	5,488	6,988	9,388	300
Energy Storage	4,100	5,750	9,800	300
Merchant PPA / Hydrogen-ready CTs	1,859	1,135	0	4,753
Microgrid	125	125	0	275
TOTAL	14,276	16,752	21,992	8,332

Finally, Table 7-6 presents the APS generation portfolio additions in their entirety by path through 2035, which includes all projected additions to the APS system over the entire IRP evaluation period. This is followed by Table 7-7 that shows the entire portfolios and energy mix including existing resources.

TABLE 7-6. RESOURCE ADDITIONS: FUTURE RESOURCES (2020-2035)

2020-2035 ADDITIONS (MW)	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO	TECHNOLOGY AGNOSTIC PORTFOLIO
Demand Side Management	1,602	1,602	1,602	1,602
Demand Response	693	743	793	693
Distributed Energy	1,585	1,585	1,585	1,585
Renewable Energy	6,450	7,950	10,375	750
Energy Storage	4,850	6,500	10,550	850
Merchant PPA / Hydrogen-ready CTs	1,859	1,135	0	5,115
Microgrid	131	131	6	281
TOTAL	17,170	19,646	24,911	10,876

While the above table indicates in total how much merchant PPA and hydrogen ready CTs are in the portfolios by 2035, it is also important to understand how that compares with the amount of merchant PPAs currently under contract (1,598 MW). The Bridge portfolio shows 1,859 MW of merchant PPA/hydrogen-ready CTs in 2035, which is only 261 MW more than currently under contract. Shift and Accelerate actually have 463 and 1,598 MW less merchant PPA/hydrogen-ready CT than are under contract today.

FIGURE 7-5. 2030 & 2035 ENERGY MIX

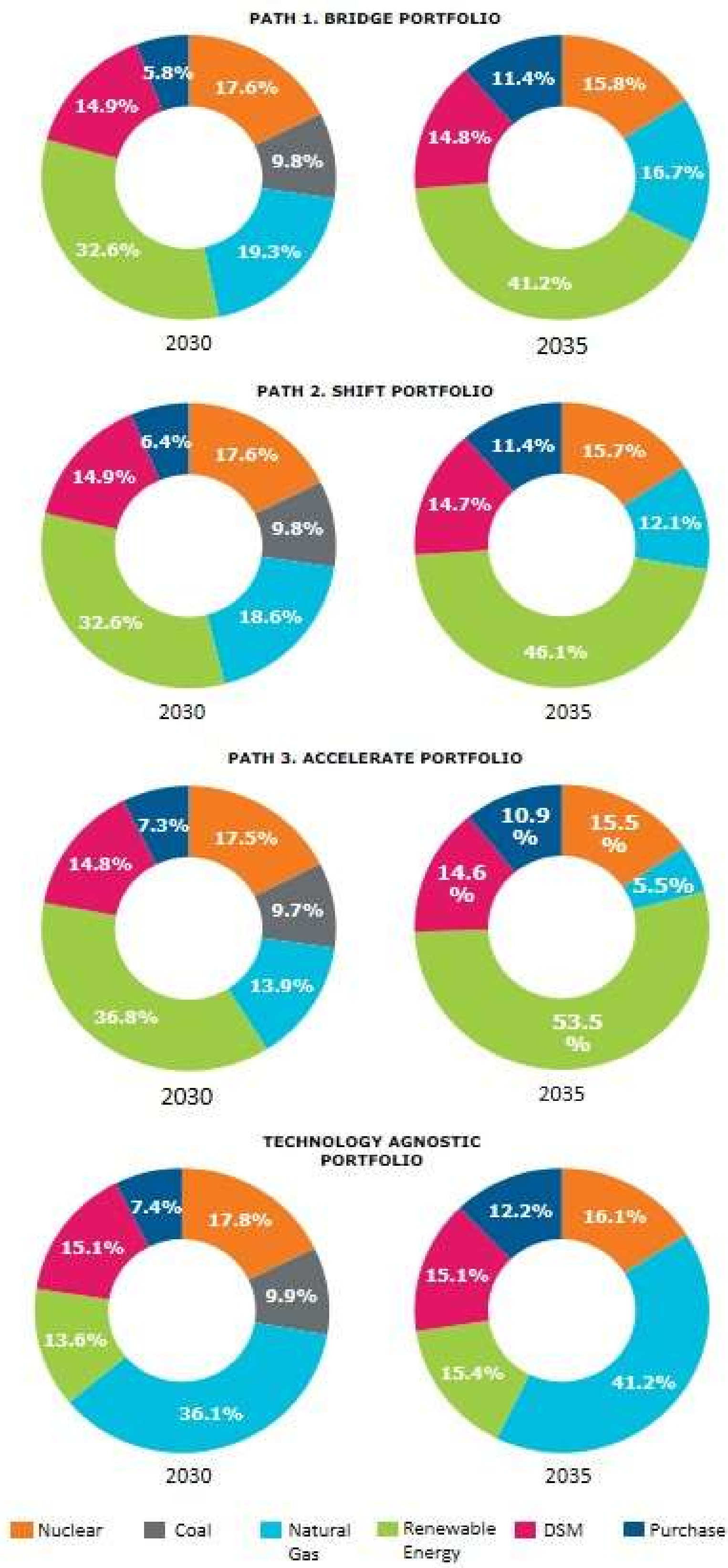


TABLE 7-7. RESOURCE CONTRIBUTIONS (2035 NAMEPLATE CAPACITY / % ENERGY MIX)

	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO	TECHNOLOGY AGNOSTIC PORTFOLIO
Description	Retire coal by 2031; demand reducing DSM; RE and ESS to meet CEC, gas bridge - extend gas tolling PPAs and add new gas generation	Retire coal by 2031; demand reducing DSM; shift to more RE and ESS, extend gas tolling PPAs and no new gas generation	Retire coal by 2031; demand reducing DSM; accelerate RE and ESS, no gas tolling PPAs and no new gas generation	Retire coal by 2031; demand reducing DSM; limited RE and ESS, extend gas tolling PPAs, new gas generation not constrained
Clean Energy	79%	84%	91%	52%
RES achieved	58%	66%	77%	21%
Nuclear	1,146 MW / 15.8%	1,146 MW / 15.7%	1,146 MW / 15.5%	1,146 MW / 16.1%
Coal	0 MW / 0.0%	0 MW / 0.0%	0 MW / 0.0%	0 MW / 0.0%
Natural Gas	5,440 MW / 16.7%	4,716 MW / 12.1%	3,581 MW / 5.5%	8,696 MW / 41.2%
Renewable Energy (RE & DE)	9,830 MW / 41.2%	11,330 MW / 46.1%	13,755 MW / 53.5%	4,130 MW / 15.4%
Demand Side Management (DSM)	1,602 MW / 14.8%	1,602 MW / 14.7%	1,602 MW / 14.6%	1,602 MWe / 15.1%
Demand Response[9]	727 MW	777 MW	827 MW	727 MW
Microgrids[9]	163 MW	163 MW	38 MW	313 MW
Energy Storage[10]	4,852 MW	6,502 MW	10,552 MW	852 MW
Market Purchase[11]	160 MW / 11.4%	160 MW / 11.4%	160 MW / 10.9%	160 MW / 12.2%

Results of Portfolio Analysis

This section provides a summary and discussion of results for the portfolios under the base assumptions. Detailed information is provided in the attachments including annual resource plans, energy mix (GWh and %), revenue requirements, system average costs, cumulative capital expenditures, gas usage, carbon emissions and water use. Please see Attachment F.1(b) through Attachment F.1(b)(5).

Results are shown in absolute terms in the following tables, but portfolio costs and performance are compared to Path 1 - Bridge portfolio in the discussion as a matter of convenience. All Path portfolios allow the Company to meet its clean energy commitment and illustrate trade-offs associated with resource alternatives. As noted throughout the IRP, the Technology Agnostic portfolio is included for reference purposes only and is not considered a viable path forward by APS.

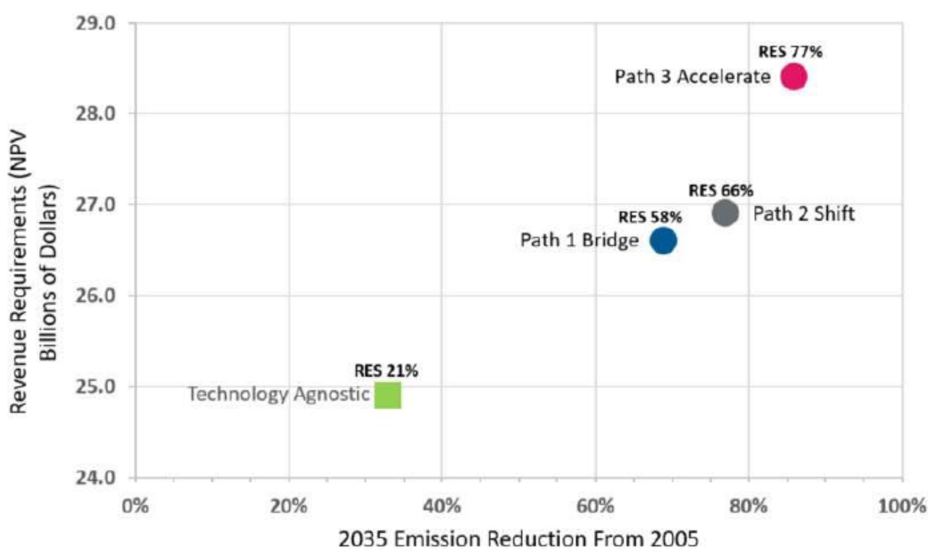
[9] DR and microgrids are considered capacity resources and are not included in the energy mix.

[10] Energy storage does not create its own energy, so energy associated with it is reported under the source that provided the charging energy.

[11] Market Purchase capacity (MW) reflects firm power acquired through PPAs, while Market Purchase energy mix % includes firm purchases plus non-firm market wholesale purchases.

There are many trade-offs and considerations in the analysis of the portfolios, and one of the most important trade-offs is between the cost of the portfolios and the amount of carbon reduction achieved. That trade-off is summarized in Figure 7-6 which demonstrates that costs increase with a move from the Bridge to Shift portfolio and increase more rapidly when moving from the Shift to Accelerate portfolio. Energy storage and renewables show diminishing returns to carbon reductions when exceeding a 60%-70% RES. The results suggest that as high levels of renewable energy and energy storage are approached on the system, advances in long-duration energy storage technology and cost reductions will become increasingly critical to helping meet the Company's clean energy and affordability goals.

FIGURE 7-6. PORTFOLIO COST AND CO2 EMISSION REDUCTION



SUMMARY OF PORTFOLIO ANALYTICS

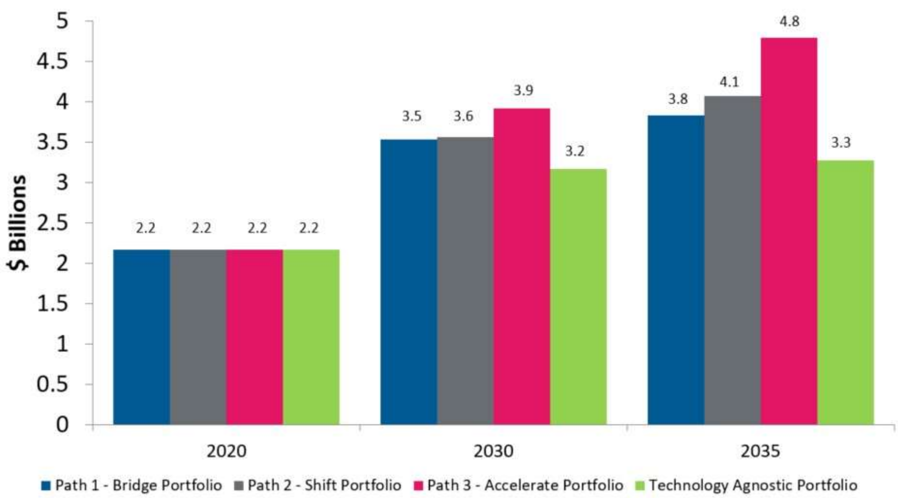
TABLE 7-8. SUMMARY OF PORTFOLIO RESULTS

	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO	TECHNOLOGY AGNOSTIC PORTFOLIO
Clean Energy	79%	84%	91%	52%
RES Achieved	58%	66%	77%	21%
Revenue Requirement NPV 2020-2035 $Billions	26.6	26.9	28.4	24.9
$/MWh System Cost Avg Annual increase 2020-2035 % per Year	1.3%	1.7%	2.8%	0.2%
Cumulative Capital Exp 2020-2035 $Billions	17.9	20.8	28.1	8.9
CO2 Emissions 2035 Reduction from 2005	69%	77%	86%	33%
Renewable Curtailment in 2035	17%	20%	23%	0%
Water Use in 2035 Thousand Acre-Feet	36.0	33.6	30.2	42.5
Gas Usage in 2035 - BCF	74.0	53.9	27.3	176.7

KEY METRIC COMPARISON

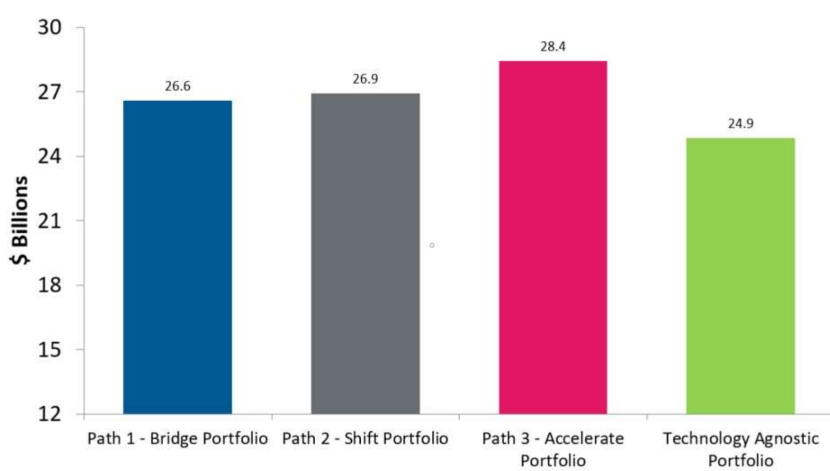
Annual revenue requirements steadily rise over the course of the Planning Period for all portfolios. Costs are driven by the large capital investment needed to support clean goals and load growth, increasing fuel prices, inclusion of assumed carbon tax, and increased operation and maintenance costs.

FIGURE 7-7. ANNUAL REVENUE REQUIREMENTS



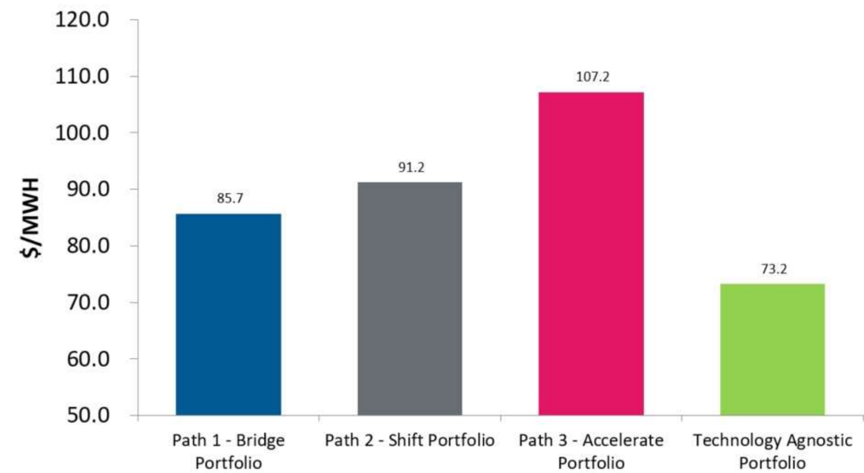
In the net present value of revenue requirements, the Bridge portfolio has the lowest NPV while the NPV costs of Shift and Accelerate portfolios are higher by 1.2% and 7.0%, respectively.

FIGURE 7-8. NPV OF REVENUE REQUIREMENTS



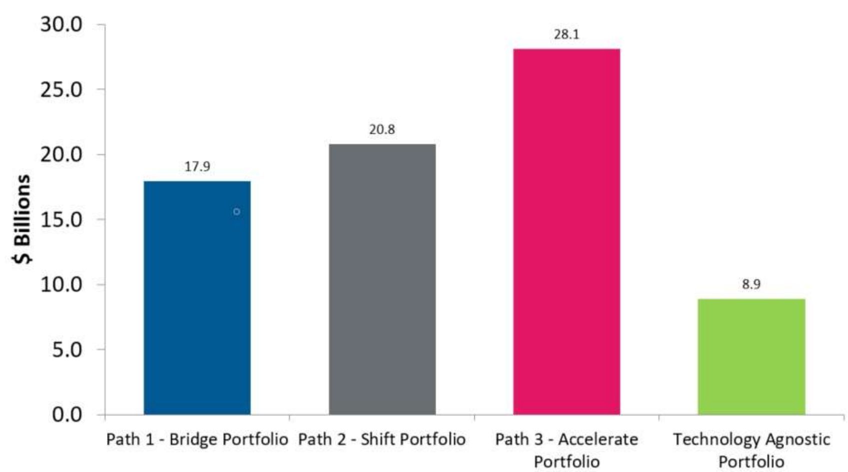
System average costs in $/MWh are the lowest in the Bridge portfolio generally reflecting the cost of resource additions. Based on these results, both Shift and Accelerate can potentially hold cost increases below the rate of inflation, a key affordability consideration for APS customers.

FIGURE 7-9. SYSTEM AVERAGE COST IN 2035



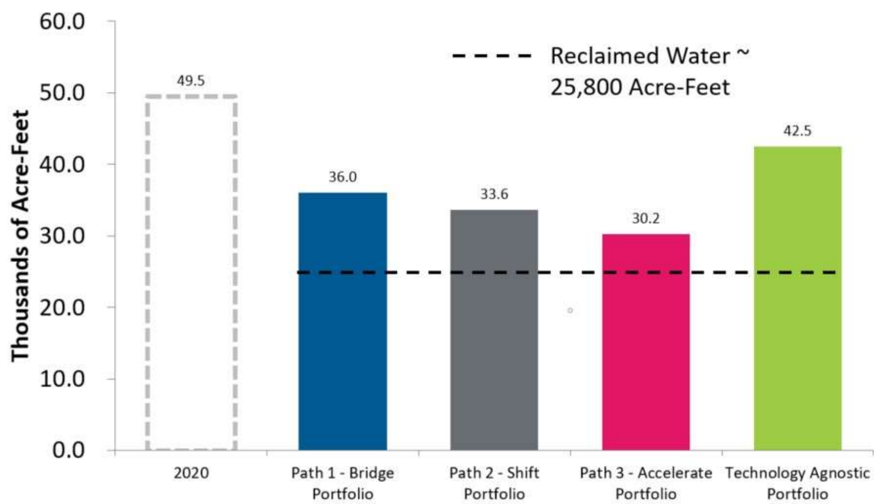
The cumulative capital expenditures required to support the Bridge portfolio are $17.9 billion over the Planning Period. This includes construction costs of new generation technologies as well as capital expenditures for existing plants and new generation related transmission (and excludes items such as distribution, transmission reliability, other customer costs, etc.). Shift and Accelerate require capital expenditures of $2.9 and $10.2 billion more than Bridge over the Planning Period, respectively.

FIGURE 7-10. CUMULATIVE CAPITAL EXPENDITURES 2020 – 2035



Water use is expected to drop from 49,500 acre-feet in 2020 to 36,000 acre-feet in 2035 in the Bridge portfolio, a decrease of 27%. The Accelerate portfolio uses the least amount of water, or a 39% reduction from 2020 water consumption. Note that approximately 72% to 85% of the water consumption in the three Path portfolios in 2035 is reclaimed water used in Palo Verde and Redhawk, not surface or groundwater.

FIGURE 7-11. WATER USE IN 2035



All three of the Paths offer substantial reductions in carbon emissions and make significant progress toward meeting the Company's long-term goal of zero carbon emissions by 2050. By the end of the Planning Period, the Bridge portfolio reduces carbon dioxide emissions 69% below 2005 levels. The Shift portfolio reduces carbon dioxide emissions by 77% and the Accelerate portfolio reduces carbon dioxide emissions by 86% by the end of the Planning Period.

FIGURE 7-12. CO2 EMISSIONS 2005 vs. 2035

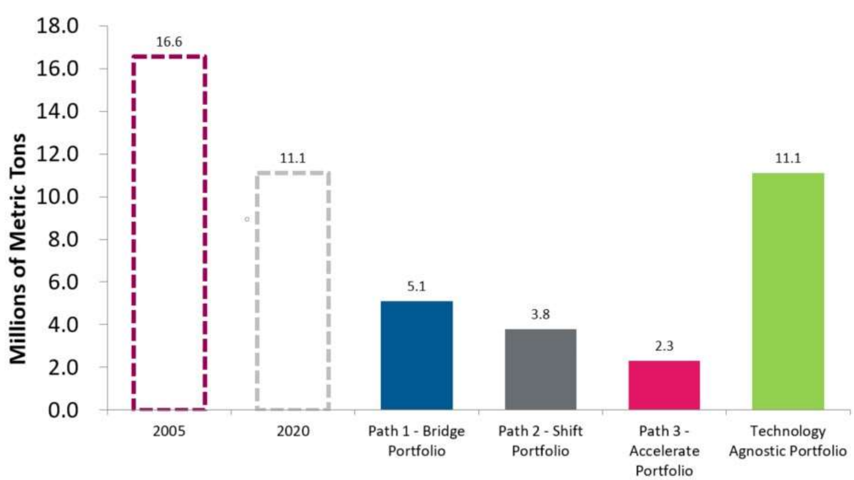
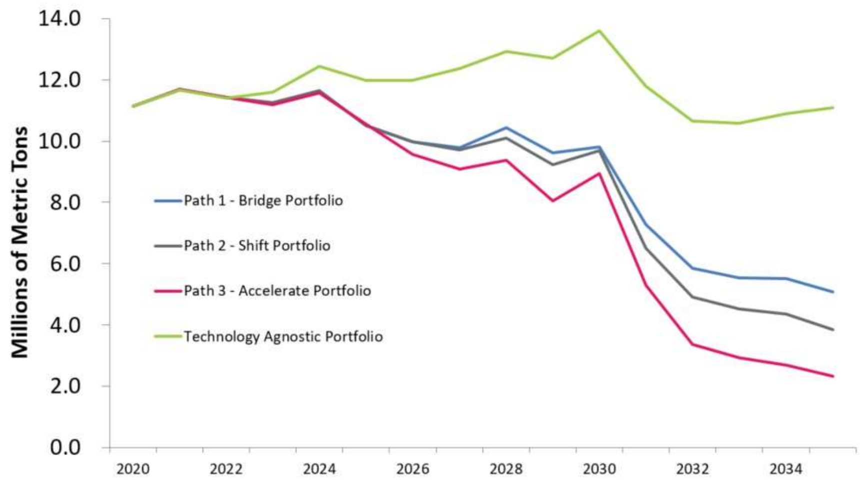
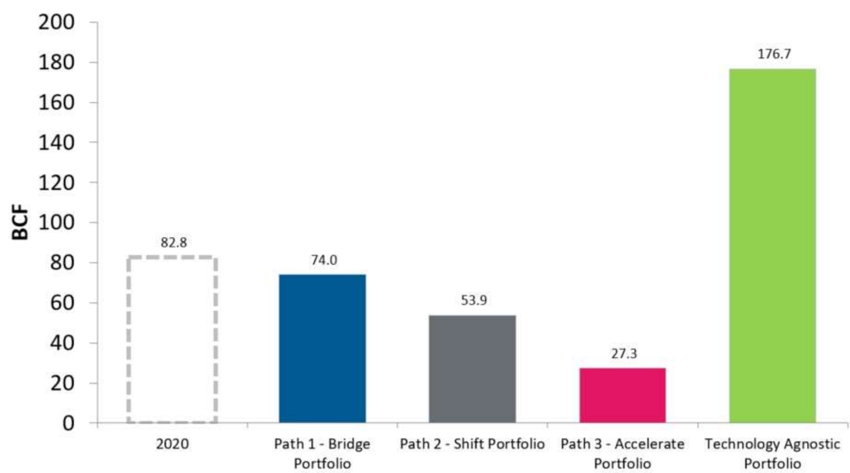


FIGURE 7-13. PLANNING PERIOD CO2 EMISSIONS REDUCTIONS (2020-2035)



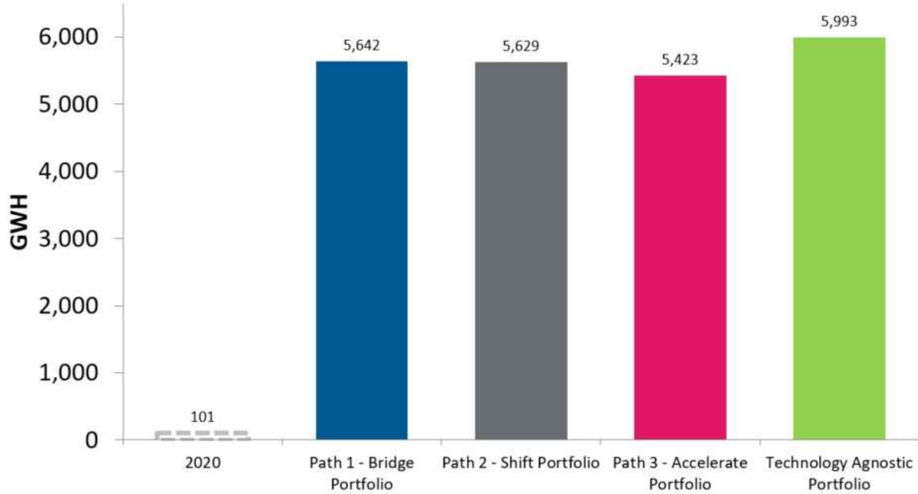
All three of the Path portfolios reduce APS's natural gas usage from the beginning of the Planning Period to the end of the Planning Period despite serving customer load growth and retiring the Cholla and Four Corners coal fired power plants. In the Bridge portfolio, natural gas usage at the end of the Planning Period is almost 9 BCF (11%) below 2020 levels. The Shift and Accelerate portfolios reduce natural gas usage by 29 BCF (35%) and 56 BCF (67%) respectively over the Planning Period.

FIGURE 7-14. NATURAL GAS USAGE – 2035



By 2035, APS expects the increasing amounts of renewable energy installed on the Western grid will result in significant amounts of low-cost or negatively priced energy being available for APS to purchase for the benefit of its customers. All three Path portfolios provide flexibility needed to purchase low-cost or negatively priced energy in the wholesale energy market. These potential purchases are expected to reduce the amount of natural gas used by APS's power plants, and result in reduced carbon emissions and water use. This is an important component of meeting the clean energy commitment. In 2035, the model estimated market purchase across all three cases in the range of 5,400 to 5,600 GWHs.

FIGURE 7-15. WHOLESALE MARKET PURCHASES



Discussion of Results

The results presented above illustrate the trade-offs in key metrics between the portfolios under the base assumptions.

The Bridge portfolio results in 67% clean energy by 2030 and 79% clean energy by 2035. It has the lowest NPV cost of the three Path portfolios that enable APS to meet its clean energy commitment. Furthermore, it holds annual cost increases well below the rate of inflation[12] while reducing natural gas usage and reducing carbon emissions 69% from 2005 levels. It extends PPAs of two natural gas combined cycle tolling agreements and adds 700 MW of hydrogen-ready combustion turbines to the system. The PPA extensions and hydrogen-ready turbines act as a bridge to a carbon-free future in that they provide an affordable way to meet reliability requirements while allowing some extra time for development of longer duration storage technologies and carbon free hydrogen production which may also have diversity impacts on the future resource mix as well.

The Shift portfolio shifts 1,500 MW more renewables than Bridge into the plan and produces a 68% clean energy mix by 2030 and 84% clean energy mix by 2035. Its estimated cost is $0.3 billion NPV more than Bridge, and also holds cost increases below the rate of inflation[13]. It reduces natural gas usage by 35% below 2020 levels and reduces carbon emissions 77% below 2005 levels. It also allows time for the development of longer duration storage technologies by extending the gas tolling PPAs, which may not be needed again as the contracts roll off.

The Accelerate portfolio accelerates renewables and energy storage technology to meet all future resources required for load growth and system reliability. It results in over 73% clean energy in 2030 and 91% clean energy by 2035. It reduces natural gas usage by 67% below 2020 levels and reduces carbon emissions 86% below 2005 levels. Due to the diminishing returns of renewable and energy storage at high levels of penetration, this portfolio required over 7,500 MW more nameplate capacity than the Bridge portfolio. Given the cost outlook for renewable and storage technologies as of today, and the extensive amount of long duration storage required, this plan costs $1.8 billion more in NPV, and has cost increases above the rate of inflation[14]. This portfolio illustrates the trade-off between cost and speed of resource additions, as it indicates the higher cost of eliminating the remaining amounts of carbon dioxide from emissions at a more rapid rate than the other portfolios. Additional sources of clean energy may be required to diversify the portfolio as incremental amounts of both renewables and storage are showing a declining marginal contribution to a cleaner energy mix. This portfolio, as modeled, will result in achieving the clean energy commitment more quickly than the others.

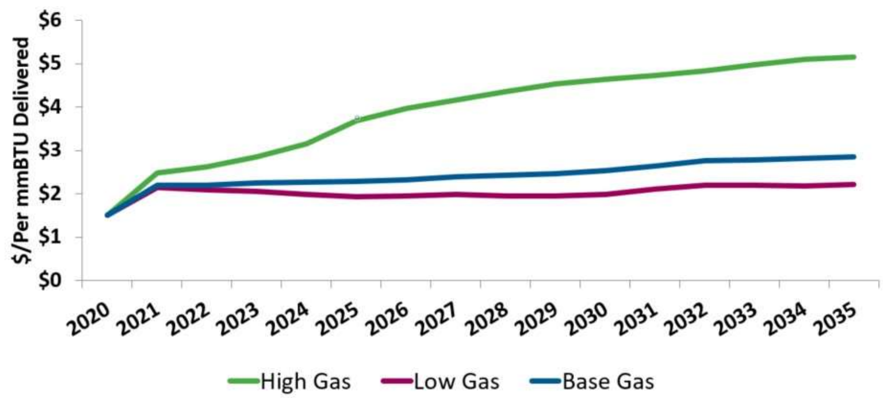
[12] Revenue requirements herein include generation and incremental related transmission costs, and do not include all components of customer rates. Holding these cost increases below the rate of inflation does not necessarily mean that rate increases will be below the rate of inflation.
[13] See note above.
[14] See note above. Generation and related transmission cost increases above the rate of inflation does not necessarily mean that rate increases for this portfolio would be above the rate of inflation.

Sensitivities

Six sensitivities were developed to help assess the economic risk associated with each of the three Path portfolios that would enable APS to meet its clean energy commitment. ACC Decision No. 76632 required evaluation of a wide variety of natural gas prices, no load growth and low load growth (<1%) scenarios. Each of the base assumptions were stressed as described below.

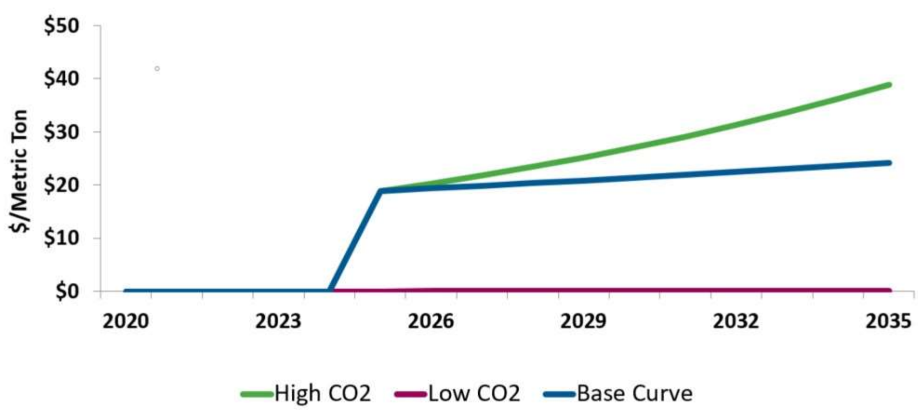
Natural Gas Prices – A wide variety of natural gas prices is required by ACC Decision No. 76632. Low and high prices were developed based on the wide range of low and high natural gas price scenarios projected by the Energy Information Administration in its 2020 Annual Energy Outlook. By 2035, the low sensitivity prices are 23% lower than the base, and the high sensitivity prices over 75% higher than the base.

FIGURE 7-16. NATURAL GAS PRICE SENSITIVITY



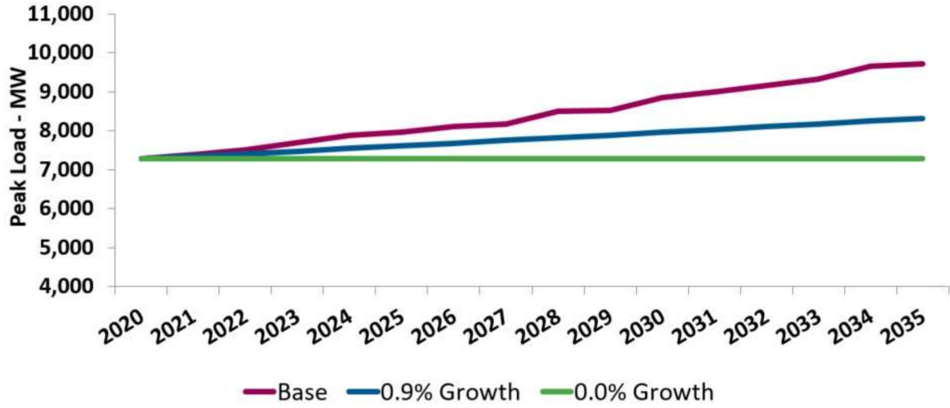
Carbon Prices - Carbon prices range from a low of zero, representing a situation in which carbon legislation is not enacted or does not apply to APS's generating units, to a high of ~$19/metric ton in year 2025 escalating at 7.5% per year.

FIGURE 7-17. CARBON PRICE SENSITIVITY



Load Growth – Load growth after rooftop solar and DSM is 2.1% per year in the base. The Commission required two low load growth sensitivities. Load growth in the sensitivity cases are 0.0% and less than 1% (APS chose to run 0.9%). A high load growth case was not performed at this time.

FIGURE 7-18. LOAD FORECAST SENSITIVITY



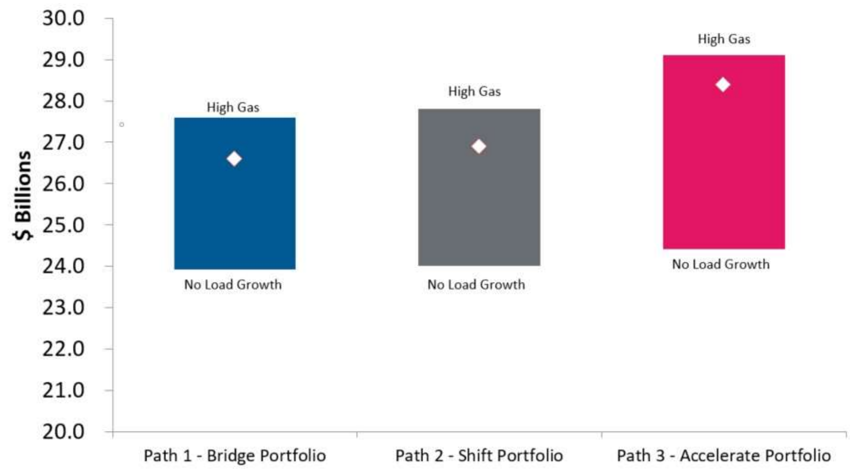
Results of Sensitivity Analysis

While the values of the metrics associated with the base assumptions are most useful in making resource decisions, key variables are also stressed both upward and downward to evaluate the robustness of each portfolio. Robust portfolios are relatively less sensitive to changes in the assumptions and perform better over a wide range of assumptions. This section summarizes the base assumption results and the ranges of results in the key metrics for the six sensitivities and the three Path portfolios. For each of the metrics, a figure is presented indicating the values using the base assumptions for each portfolio (represented by a diamond), and the highest and lowest values for each portfolio across the sensitivities (represented by a bar). The figures also may indicate which sensitivity creates the highest and lowest values for each portfolio or the variance across cases. Large variance is less desirable from a customer perspective but must be weighed against the relative cost level. For example, high cost, low variance may not be preferred to low cost with a higher variance if costs are substantially lower across the two cases. A table follows each figure indicating the base assumption value for each portfolio and the ranges of results as a percentage of the base assumption for that portfolio.

REVENUE REQUIREMENTS NPV

The NPV of revenue requirements are bounded by the No Load Growth Sensitivity on the low end of the range and by the High Gas Price Sensitivity on the high end. The range of revenue requirements is very similar for all three Path portfolios, although Accelerate has a slightly wider range, indicating that none of the portfolios is significantly more or less susceptible to the uncertainties considered. Revenue requirements in the No Load Growth Sensitivities are lower because they are serving less load than the other sensitivities. Figure 7-19 below indicates, however, that the No Load Growth sensitivities do not result in the lowest $/MWh cost increases.

FIGURE 7-19. RANGE OF REVENUE REQUIREMENTS NPV

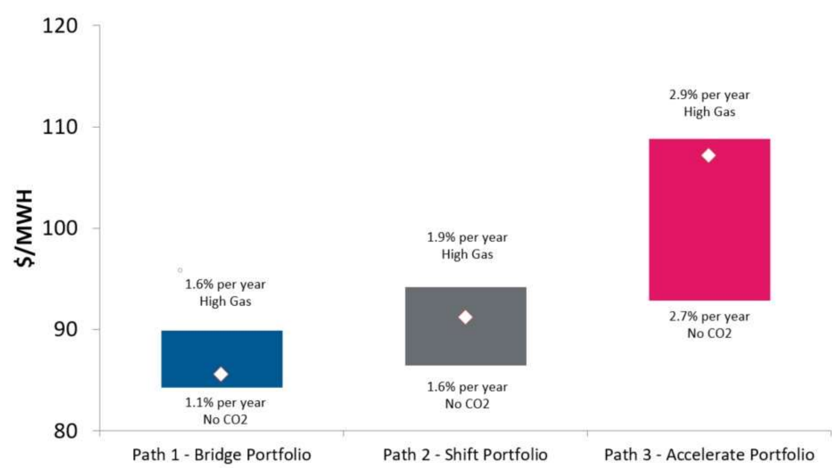


Path 1 - Bridge	$26.6 billion (-10.3% to +3.6%)
Path 2 - Shift	$26.9 billion (-10.9% to +3.3%)
Path 3 - Accelerate	$28.4 billion (-14.1% to +2.5%)

SYSTEM AVERAGE COST IN 2035

In this case, the low and high end of the cost range is associated with the low carbon and high gas price sensitivities for the portfolios. In addition to average cost per MWh, the figure indicates the annual average cost increase of each Path portfolio over the Planning Period. Bridge and Shift exhibit lower costs and tighter ranges than Accelerate, and they can potentially hold cost increases under the rate of inflation, while Accelerate may not.

FIGURE 7-20. RANGE OF SYSTEM AVERAGE COST IN 2035

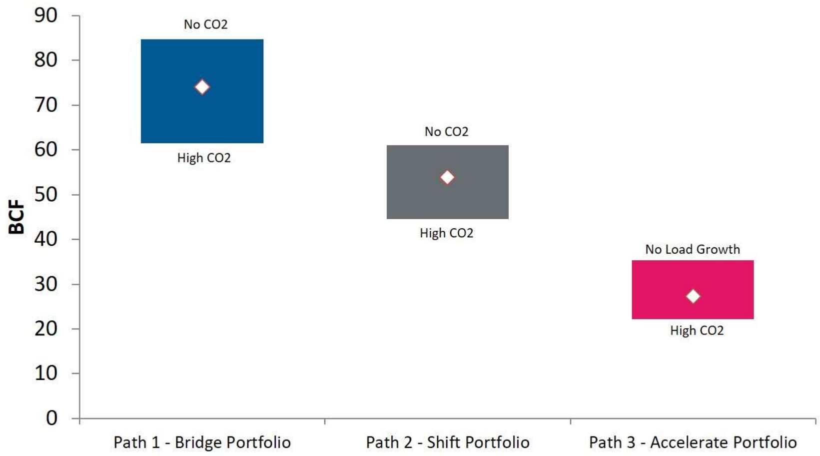


Path 1 - Bridge	85.7 $/MWh (-1.9% to +4.9%)
Path 2 - Shift	91.2 $/MWh (-5.2% to +3.4%)
Path 3 - Accelerate	107.2 $/MWh (-13.4% to +1.5%)

NATURAL GAS USAGE

The low end and high end of the ranges are defined by High CO2 costs and Low CO2 / Load Growth sensitivities. All portfolios reduce gas usage from 2020 levels of about 83 BCF.

FIGURE 7-21. RANGE OF NATURAL GAS USAGE IN 2035

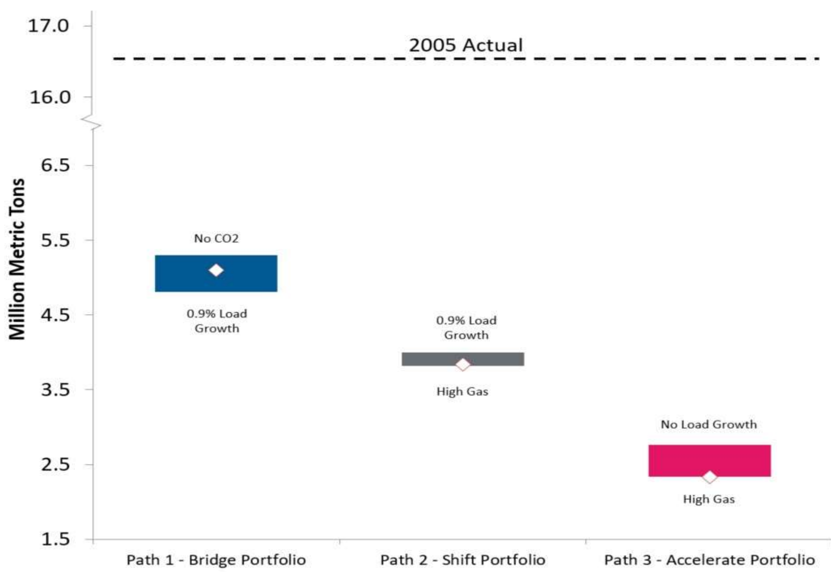


Path 1 - Bridge	74.0 BCF (-17.0% to +14.5%)
Path 2 - Shift	53.9 BCF (-17.6% to +13.3%)
Path 3 - Accelerate	27.3 BCF (-19.1% to +29.5%)

CARBON EMISSIONS

All of the Path portfolios and sensitivities show dramatic reductions of carbon emissions from 2005 levels of 16.6 million metric tons. And all sensitivities considered show a tight band, meaning that the emission levels are more dependent on the resource additions than they are on gas prices, carbon prices, or load growth.

FIGURE 7-22. RANGE OF CARBON EMISSIONS IN 2035



Path 1 - Bridge	5.1 MT (-4.8% to +3.5%)
Path 2 - Shift	3.8 MT (-0.7% to +5.0%)
Path 3 - Accelerate	2.3 MT (-0.3% to +18.5%)

WATER USE

Water use is also significantly reduced from 2020 levels of about 50,000 acre-feet per year. This is mainly driven by the retirement of all existing coal units, and the addition of renewables that consume no water.

FIGURE 7-23. ANNUAL WATER USE RANGE – 2035

Path 1 - Bridge	36.0 KAF (-2.1% to +0.9%)
Path 2 - Shift	33.6 KAF (-0.2% to +1.3%)
Path 3 - Accelerate	30.2 KAF (-0.1% to +3.6%)

Discussion of Sensitivity Results

Each of the portfolios was run through sensitivities to determine how they would perform relative to changes in key assumptions. The purpose is to identify a portfolio that performs well across many high and low cost assumptions and, further, to indicate how resource plans might change if/when it is recognized that one of the alternative futures is becoming the new reality. While summarizing all the key metrics, the following discussions focus on the economics of the portfolios.

Summary tables are provided below for the gas price, carbon price and load forecast sensitivity studies. The tables are organized such that each cell contains three values: the top cell corresponds to the low assumption, the middle value corresponds to the base assumption, and the bottom value corresponds to the high assumption as defined earlier in this chapter. In the case of load growth sensitivities, the first corresponds to no growth, the second corresponds to 0.9% growth, and the third corresponds to the base. If the different sensitivity assumptions do not cause different results than the base, only the one value is included in the table. For example, the capital additions are the same for a portfolio across the sensitivities.

GAS PRICE SENSITIVITY

Overall, the +81%/-23% change in the natural gas price assumption impacts revenue requirements between plus 4% and minus 1% across all sensitivities and portfolios, indicating that all portfolios are now well insulated from fluctuations in natural gas prices.

TABLE 7-9. SUMMARY OF GAS PRICE SENSITIVITY RESULTS

	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO
Clean Energy	Low Gas 79% Base Gas 79% High Gas 79%	84% 84% 84%	91% 91% 91%
RES Achieved in 2035	58% 58% 59%	66% 66% 66%	77% 77% 77%
Revenue Requirement NPV 2020-2035 $Billions	26.3 26.6 27.6	26.7 26.9 27.8	28.3 28.4 29.1
$/MWh System Cost Avg Annual increase 2020-2035 % per Year	1.2% 1.3% 1.6%	1.6% 1.7% 1.9%	2.8% 2.8% 2.9%
Cumulative Capital Exp 2020-2035 $Billions	17.9	20.8	28.1
CO2 Emissions 2035 Reduction from 2005	69% 69% 70%	77% 77% 77%	86% 86% 86%
Renewable Curtailment in 2035	18% 17% 17%	21% 20% 20%	23% 23% 23%
Water Use in 2035 Thousand Acre-Feet	35.9 36.0 36.0	33.7 33.6 33.6	30.2 30.2 30.2
Gas Usage in 2035 - BCF	73.7 74.0 74.0	53.6 53.9 54.0	27.3 27.3 27.6

CARBON PRICE SENSITIVITY

Overall, the low and high carbon price assumptions have a minimal impact on the NPV of revenue requirements, only about plus 0.4% and minus 3% from base assumption results.

TABLE 7-10. SUMMARY OF CARBON PRICE SENSITIVITY RESULTS

	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO
Clean Energy	Low CO2 79% Base CO2 79% High CO2 79%	84% 84% 84%	91% 91% 91%
RES Achieved 2035	58% 58% 58%	66% 66% 66%	77% 77% 77%
Revenue Requirement NPV 2020-2035 $Billions	25.8 26.6 26.7	26.2 26.9 27.0	27.8 28.4 28.5
$/MWh System Cost Avg Annual increase 2020-2035 % per Year	1.1% 1.3% 1.3%	1.6% 1.7% 1.7%	2.7% 2.8% 2.8%
Cumulative Capital Exp 2020-2035 $Billions	17.9	20.8	28.1
CO2 Emissions 2035 Reduction from 2005	68% 69% 70%	76% 77% 77%	86% 86% 86%
Renewable Curtailment in 2035	18% 17% 17%	21% 20% 20%	23% 23% 23%
Water Use in 2035 Thousand Acre-Feet	35.2 36.0 36.3	33.7 33.6 33.6	30.2 30.2 30.2
Gas Usage in 2035 – BCF	84.8 74.0 61.4	61.1 53.9 44.4	32.6 27.3 22.1

LOAD FORECAST SENSITIVITY

The load forecast sensitivities have the largest impact on the revenue requirements of all the sensitivities, impacting them by as much as minus 14% in the no growth, Accelerate portfolio case. They also have a larger impact on the other metrics as well, especially cumulative capital additions.

TABLE 7-11. LOAD FORECAST SENSITIVITY

	PATH 1 BRIDGE PORTFOLIO	PATH 2 SHIFT PORTFOLIO	PATH 3 ACCELERATE PORTFOLIO
Clean Energy	No Growth 74% 0.9% Growth 77% Base Growth 79%	80% 81% 84%	86% 89% 91%
RES Achieved 2035	51% 55% 58%	54% 57% 66%	61% 69% 77%
Revenue Requirement NPV 2020-2035 $Billions	23.9 25.2 26.6	24.0 25.2 26.9	24.4 26.2 28.4
$/MWh System Cost Avg Annual increase 2020-2035 % per Year	1.4% 1.3% 1.3%	1.5% 1.3% 1.7%	1.8% 2.2% 2.8%
Cumulative Capital Exp 2020-2035 $Billions	9.5 13.3 17.9	11.1 14.4 20.8	14.2 20.1 28.1
CO2 Emissions 2035 Reduction from 2005	71% 71% 69%	77% 76% 77%	83% 85% 86%
Renewable Curtailment in 2035	14% 22% 17%	29% 27% 20%	29% 27% 23%
Water Use in 2035 Thousand Acre-Feet	35.5 35.3 36.0	33.6 34.1 33.6	31.3 30.6 30.2
Gas Usage in 2035 - BCF	73.7 72.8 74.0	56.8 59.0 53.9	35.3 30.4 27.3

2020 Resource Plan

Based upon the foregoing portfolio and sensitivity analysis, the following observations are made:

PATH 1 - BRIDGE PORTFOLIO

- 67% clean by 2030, 79% clean by 2035
- Most affordable in terms of revenue requirements and system average cost across all sensitivities
- Lowest capital expenditure requirement across all sensitivities
- Reduces carbon dioxide emissions, gas usage and water use from 2020 levels, however, not as much as Shift and Accelerate

PATH 2 - SHIFT PORTFOLIO

- 68% clean by 2030, 84% clean by 2035
- Slightly higher cost than Bridge, however cost increases are kept below the rate of inflation across all sensitivities
- Capital expenditure requirement marginally higher than Bridge
- Reduces carbon dioxide emissions, gas usage and water use from 2020 levels with reductions between Bridge and Accelerate

PATH 3 – ACCELERATE PORTFOLIO

- 73% clean by 2030, 91% clean by 2035
- Higher cost than Bridge and Shift, with cost increases above the rate of inflation in all sensitivities
- Significantly higher capital expenditure requirement across all sensitivities
- Highest reduction in carbon dioxide emissions, gas usage and water use from 2020 levels

Conclusion

All three of the Path portfolios developed to meet APS's clean energy commitment may present viable paths forward toward achieving its objectives of clean, reliable and affordable energy. The five-year Action Plan window is the same for all three plans and are supportive of achieving the longer-term clean energy goals. The five-year Action Plan sets the Company on the right path. Both renewable energy and energy storage technologies have been improving in terms of performance and cost reductions in recent years, and such progress is expected to continue. It cannot be predicted which technologies will prevail in performance and cost-effectiveness or how quickly such advances will happen. It is important to understand that the resources represented in the later part of the Planning Period are indicative of additions but may change based on technology changes or improvements. APS believes it is prudent to take the actions outlined in the Action Plan, which includes storage and renewables through 2024, while also meeting the previously announced commitment to install 850 MW of energy storage by 2025. Further, APS is closely monitoring technology development and cost trends, learning from internal and industry experiences as projects are issued and executed projects through the Requests for Proposal process. APS is not selecting a single portfolio currently but is providing information on all three of the Path portfolios to show trade-offs and maintain flexibility in the future to pursue the most effective path as new technologies emerge and mature.

APS 2020 Resource Plans

Based upon the above analysis, APS could meet its clean energy commitment with any of three Path portfolios and is not selecting any particular portfolio at this time. The five-year Action Plan is the same for all three, and APS is maintaining its flexibility to make resource decisions outside the Action Plan window at a later date and with a better understanding of how technology development and costs are progressing. These portfolios will provide information to stakeholders that will enable informed discussions about resource options and trade-offs. The resulting resource plans, associated revenue requirements and other details can be found in Attachments F.1(a)(1) and F.1(b), respectively. All three of the Path portfolios have the following characteristics:

- Puts APS on a path to achieve its 45% renewable and 65% clean goals by 2030 and 100% clean by 2050
- Substantially reduces carbon emissions, water use and natural gas usage by the end of the Planning Period
- Maintains customer affordability with the cost of two of the paths below the rate of inflation

CHAPTER 8

ACTION PLAN

ACTION PLAN

Based on the analysis performed in the previous chapters and the conclusions drawn from the Bridge, Shift and Accelerate portfolios, we recognize our next steps are well-defined. Our 2020-2024 Action Plan, which focuses on near-term developments and has higher certainty over the next 4-5 years, establishes the actions we must begin taking today to set the Company on a path to meet our clean energy commitment.

We are excited to work with our stakeholders and make the resource commitments that will continue momentum toward a clean, reliable and affordable energy future for Arizona. Our plan builds upon customer options to manage their energy usage and bills and integrates more grid-scale renewable energy and energy storage technologies onto our system. Like any forward-looking plan, we recognize that our forecast relies on a number of assumptions that are based on information available at the time of this writing. Due to the COVID-19 pandemic, we are aware there may be changes to our projected load growth, and we are prepared to update our stakeholders and this Action Plan as more information becomes available. As we learn from experiences in pursuing our clean energy commitment, from the industry and see advances in technology, our future Action Plans will be updated to incorporate new ways of thinking to ensure we are meeting customers' desire for clean energy while achieving environmental gains and maintaining reliable and affordable service.

1. Continued Expansion of Renewable Resources

Our Bridge, Shift and Accelerate portfolios resulted in the same resource needs through the 2024 Action Plan window. To stay on track to meet our interim goal of 45% renewables by 2030, we must add approximately 300-400 MW of renewable resources annually through 2024. In order to capture renewable energy to be used when it is otherwise available, we will also need to add 200-350 MW of energy storage annually beginning in 2022. Building energy storage today will prepare us to have the capacity necessary to fully exit coal generation by 2031. In addition to the resource needs going forward, we must also bring our outstanding RFPs to close.

2. Investment in Energy Storage

In February 2019, we announced an initiative to add 850 MW of battery energy storage by 2025. We remain committed to completing this initiative, but the timing and sequence of resource additions will vary due to the impacts of the April 19, 2019 equipment failure at the McMicken battery energy storage facility.

850mw of **battery storage** by 2025

We have advised bidders participating in the APS RFPs that involve storage to stop work on their proposals until further notice. Results of the McMicken investigation will inform our next steps, including any changes to design parameters that may be implemented for future batteries. We will continue to work with RFP participants on revised requirements and timelines.

3. Request for Proposals (RFPs)

We have several RFPs outstanding at this time. These include:

- 2019 photovoltaic + storage (PVS) RFP requested 150 MW of PVS, which was paused pending the McMicken investigation
- 2019 photovoltaic (PV) Solar RFP requests 150 MW of battery-ready solar additions to the APS generation portfolio by 2021
- 2019 Wind RFP requests 250 MW of wind to be in service no later than 2022
- 2020 Demand Response (DR) RFP requests 75 MW of DR to be in service for summer of 2021

As these RFPs progress, we will keep parties appraised of the situation. Additionally, based on the expected energy and capacity needs shown in this IRP filing, we expect to issue an additional RFPs open to all resource types (all-source) sometime later this year.

4. Investment in APS Solar Communities

An expansion of rooftop solar installations for limited- and moderate-income customers was approved by the Commission in August 2017. The program, under which APS owns and controls the generation, renewable energy credits and other program attributes, requires us to invest from $10 million to $15 million annually from 2018-2020 in rooftop solar for single-family and multifamily homes, allocating at least 65% of annual program expenditures to residential installations. Although the program focuses primarily on single-family homes, it also is available to multifamily housing, Title I schools, nonprofits aiding limited-income groups and government entities serving rural communities located in our service territory. The program is no longer open to new enrollees, but the ongoing evaluations and benefits to customers over the life of the system will help APS remain an innovator in integrating distributed solar onto the grid.

5. Innovation in Customer-Side Resources

We are offering programs that both help customers save money and energy and have the greatest resource value, with emphasis on load shifting and reducing peak load. The following programs focus on customer participation and simplicity by aligning technologies, rates and the grid's operational needs.

TAKE CHARGE AZ

EVs can help Arizona achieve an increasingly clean energy mix and cleaner air. Drivers are expected to have more than 130 EV models to choose from by 2022, but barriers to adoption still exist. We seek to make driving EVs convenient for participating customers by reducing range anxiety through access to more charging infrastructure.

The APS Take Charge AZ pilot programs offer free EV charging equipment, including installation and maintenance, to businesses, government agencies, nonprofits and multifamily communities. Participants pay for the electricity used to charge EVs, which they are encouraged to do when solar energy is abundant and energy prices are lower.

DSM IMPLEMENTATION PLAN

The APS 2020 DSM Plan (filed on December 31, 2019, amended May 18, 2020) consolidates and incorporates all elements of the 2018 and 2019 DSM Plans currently awaiting Commission review. Our 2020 DSM Plan continues our work to reshape DSM to better align with excess production of electricity in the middle of the day from solar generation and peak reductions in the evening when the sun has set. This translates to customer savings on bills and emissions reductions from using clean midday solar output. Among other measures, the plan proposes to continue the 2017 Demand Response, Energy Storage, Load Management program (see APS Rewards programs), which supports deployment of residential load management, demand response and energy storage technologies. The technologies help residential customers shift energy use and manage peak demand while reducing their energy costs.

Further, our 2020 DSM plan commits to funding our Limited Income Weatherization Program by an additional 50% and focuses on disadvantaged communities and limited-income multifamily properties. We are also expanding our education and outreach to help our customers make choices to reduce energy consumption when possible and shift energy usage to clean, lower-cost portions of the day when reduced consumption is not possible.

The 2020 DSM Plan also includes a proposed new pilot initiative for EV load management, new measures designed to address new data center loads with energy efficiency savings opportunities and proposed pilots for beneficial electrification measures that provide energy cost savings, emissions reductions and flexible electric loads that can be managed to flatten system load shapes by charging EVs during appropriate off-peak times.

APS REWARDS PROGRAMS

We have implemented a number of demand response and load management programs that facilitate emerging energy storage technologies such as grid-connected batteries, water heaters, and smart thermostats throughout our service territory. The increasing adoption of rooftop solar is rapidly changing system load shapes and creating need for more flexible resources to back up intermittent solar generation. Customer-sited batteries, water heaters, and thermostats, or distributed energy resources that support load management, demand response and load shifting to help meet these flexible resource needs by limiting peak demand and shifting energy use away from peak periods and toward midday, when rooftop solar production is highest.

The Rewards portfolio include the following programs and technologies, plus a platform to manage the devices:

- **Cool Rewards (demand response)** – APS has enrolled more than 19,300 connected residential smart thermostats in this demand response program in which we can operate the thermostats to reduce load during summer system peak events. By year-end 2020, We expect to be managing up to 35,000 connected thermostats in the Cool Rewards program.

- **Reserve Rewards (thermal storage) –** APS has enrolled 219 connected heat pump water heaters that shift water heating to the middle of the day when clean solar power can be used and reduce electric consumption during our evening peak.

- **Storage Rewards and Intermediate Feeder Energy Storage (battery storage) –** This includes 37 residential batteries deployed on targeted distribution feeders and 1-2 commercial-scale batteries and intermediate feeder energy storage deployed on targeted distribution feeders.

6. Short-Term Summer Peaking Needs

With the revised battery project timelines, we will likely use existing gas generation in the region as a bridging strategy to meet the projected load plus reserve margin. These short-term purchases ensure that we can meet summer reliability requirements and will be structured not to impact longer-term resource planning strategies. Currently, we expect short-term needs will be met with wholesale market purchases from a combination of existing merchant natural gas units, neighboring utilities and wholesale market participants.

7. Palo Verde Lease Extension

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. Through those agreements, APS retains the assets through 2023 under one lease and 2033 under two other leases. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years or return the assets to the lessors.

8. Natural Gas Transition

Managing customer affordability is an important element of the clean energy commitment. We will need to transition a large quantity of fossil fuel peaking capacity to clean peaking capacity over the next 30 years. This capacity is expensive to replace, and currently, energy storage is one of the few clean resources available in Arizona that can meet the need. In addition, natural gas prices are historically low and are expected to remain low into the foreseeable future.

Along with its affordability, natural gas is a source of reliable system capacity that will allow us to transition the fleet while maintaining a reliable safety net for the system should any new resource projects be delayed. Natural gas will help us to negotiate the best possible prices for new resources by providing flexibility in renewable and clean peaking capacity timing.

Natural gas-fired turbines are also increasingly showing the ability to be co-fired or exclusively fired by hydrogen. For these reasons, we recognize that the entire natural gas fleet should not be replaced overnight and expect to use gas as a transition fuel to a cleaner future while maintaining affordability.

9. Investment in APS Transmission System

TRANSMISSION RESOURCES

With nearly 1.3 million customers across the state depending on us for reliable and affordable electric service, we rely on our network of transmission and distribution lines to safely deliver power. In planning the future development of our transmission infrastructure, we consider a broad range of technologies, including generation, transmission and distribution resources and non-transmission alternatives to address the challenges of an increasing array of resource types and geographies.

The 2020-2029 Ten-Year Transmission System Plan[1] includes approximately 26 miles of 230-kV transmission lines, 3 miles of 115-kV transmission lines and 38 new transformers. The total investment for the projects is estimated at approximately $590 million. Annual updates to the Ten-Year Transmission System Plan will address future needs and opportunities as they develop.

TRANSMISSION SYSTEM OPTIMIZATION

We recently announced on our OASIS website that we will use a new methodology for transmission system utilization. We will transition from a Rated System Path Methodology (MOD-029) to a Flowgate Methodology (MOD-030) for the calculation of Available Transfer Capability (ATC). This transition process will take approximately two years to complete and will result in more efficient use of and greater capacities for our transmission system, may result in some avoided future transmission build, may provide more flexibility in siting generation resources and will save customers money.

10. Extended Day Ahead Market (EDAM)

The Western electric grid is evolving significantly in order to reduce greenhouse gas emissions from electricity production. Changes to the wholesale market structure will be needed to integrate additional renewable resources reliably and economically onto the grid. We are working actively with the CAISO and other regional utilities in the design of a new market, called EDAM (Extended Day-Ahead Market), that takes advantage of the existing CAISO and Energy Imbalance Market (EMI) infrastructure. This new market would facilitate operation of renewable resource production in a manner that improves reliability and reduces curtailment when excess production occurs in some areas. We participated in a feasibility assessment with other EIM entities to evaluate extending EIM to this day-ahead market. While we have not yet made a decision to join the EDAM, APS is participating in the market design and stakeholder processes now underway. This again is an opportunity for the region to optimize its renewable energy resources and provide savings to customers.

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[1] Arizona Public Service Company 2020-2029 Ten-Year Transmission System Plan, Docket No. E-00000D-19-0007.

RESPONSE TO RULES

SECTION C
DEMAND

RESPONSE TO RULES SECTION C – DEMAND

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(C), which specifically requires information related to system load forecasts.

RULE C.1

Fifteen-year forecast of system coincident peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible power; for resale; and for energy losses.

A fifteen-year forecast of peak load by month and year by customer class is provided in Attachment C.1(a) and a fifteen-year forecast of energy consumption is provided in Attachment C.1(b). For the commercial and industrial classes, the information is consolidated into a category for customers with loads less than 3MW and a category for customers with loads greater than or equal to 3MW. Since demand response programs are treated as a resource, there is no load reduction in the forecast attributed to interruptible power.

RULE C.2

Disaggregation of the load forecast of subsection (C)(1) into a component in which no additional demand management measures are assumed, and a component assuming the change in load due to additional forecasted demand management measures.

The line labeled "Own Load Peak – After DE Before EE/DR" in Attachment C.2 provides a disaggregation of the load forecast by month and year into a component in which no additional demand management measures are assumed. Within the same exhibit, a disaggregation of the load assuming the change in load due to additional forecast demand management measures is provided on the lines labeled "Energy Efficiency Programs" and "Demand Response Programs." Consistent with the definition of Demand Management in R14-2-701 of the Resource Planning Rules, both energy efficiency and demand response are included in the disaggregation because they include programs that could provide a beneficial reduction in the total cost of meeting electric energy service needs by reducing or shifting in time electricity usage.

Time of use (TOU) rates may also be considered demand management measures. TOU energy rates have been in effect at APS since 1982 and have already been accounted for in the Total Own Load Peak forecast in Attachment C.2. APS has eliminated inclining block rates, increased adoption of TOU energy and demand rates, and aligned peak rate hours with system peak hours (3-8pm) in its past rate case. These changes are expected to provide additional demand reduction in the future.

RULE C.3

Documentation of all sources of data, analyses, methods, and assumptions used in making the load forecasts, including a description of how the forecasts were benchmarked and justifications for selecting the methods and assumptions used.

The APS load forecast is developed from several different class-level analyses, which account for differences in the way customers use electricity. These analyses reflect the high relative importance of regional population and economic growth as a determinant of future electricity demand. The following discussion outlines the methods used to prepare the load forecasts for each relevant class of customer and, per the requirement of the Rules, provides a description of how the models are benchmarked and the justification for the forecast method.

RESIDENTIAL LOAD

The residential load forecast is the product of a residential customer forecast and a corresponding electricity-use-per-customer forecast. The residential customer forecast is tied to a forecast of statewide population by year, a forecast of the number of people per household, and a forecast of the share of a given region of the state which will be served by APS.

The U.S. Census Bureau reports historical population and household data. The change in annual population is disaggregated into a component driven by net natural increase (number of births each year less the number of deaths each year) and a component driven by net migration. Each of these components is expressed as a growth rate, and these rates are extrapolated forward. The historic net natural increase rate (over the past 40 years) is remarkably stable at about one percent per year, but is has declined slowly in last decade, so the extrapolation into the future reflects this trend. APS uses statistical models of net migration developed by the Economic and Business Research Center at the University of Arizona as the foundation for the net migration forecast. These models capture in-migration and out-migration flows separately and control for differences in the age of migrants as well as the regions from which they are arriving or to which they are moving.

The forecast of population resulting from the application of these projected growth rates into the future is then benchmarked against other publicly available forecasts for reasonableness. These publicly available sources include the Arizona Department of Administration and the University of Arizona Eller College of Management.

The projected growth in population necessarily implies a growth in residential households, as well. The relationship between households and population is typically expressed as the number of people per household (PPH). The historical rate of people per household has declined substantially over the last 40 years as the population has aged, although the rate of decline has slowed in more recent years. This historic rate is extrapolated into the future by combining information about the percent of each age cohort that are heads of household with the projected age distribution in order to accurately reflect the impact the continued aging of the population will have on the number of people per household. The forecast of people per household is combined with the forecast of population to derive the residential household forecast.

The number of residential electric customers expected in the future is predominately influenced by the expected growth in residential households, adjusted for service territory shares of various regions within the state. For example, APS serves approximately 45 percent of Maricopa County, but has been receiving about 50 percent of the new households each year. APS serves none of Pima and Mohave counties, but almost all of Yuma, Yavapai, and Coconino counties. These historic trends in the share of new households within a region are extrapolated into the future and reflect an assessment of the degree to which those trends may continue. The result is a forecast of APS residential customers by year which reflects anticipated changes in migration rates, the age distribution of the population, and the regional location of new households.

The forecast of electricity use per customer is developed with a regression analysis of historical usage, coupled with short-run forecast dynamics that are expected to occur along with the business cycle. The statistical modeling approach to forecasting usage is a multiple linear regression model, which estimates the historical relationship between residential electricity usage and the following independent variables: cooling, heating, home size, the real price of electricity, and real personal income per capita for Arizona.

The cooling and heating variables capture the effects of weather on usage through heating degree-days, cooling degree-days, and humidity. In addition to weather data, the cooling and heating variables are constructed by including interaction effects, which provides a better estimation of weather impacts on usage. The interactions in the cooling and heating variables are constructed similarly and both include historical saturation data, an assumption of historical efficiency improvements, and average home size. Historical saturation data for air conditioning and electric space heating is compiled from appliance ownership surveys of APS customers. Forecasts of these saturations, in combination with the number of residential customers, determine how many electricity-using applications are expected to be active in the future. Data on average home size is based on assessor data and the previously mentioned customer surveys.

The historical relationships from the regression model are applied to forecasts of the cooling and heating variables, average home size, real price of electricity, and Arizona real personal income per capita. Electricity use for cooling and heating is projected based on an assumption of normal weather, an assumption of efficiency improvements for new and replacement air-conditioning and electric heat units, and for increases in average home size. Normal weather reflects the most recent 10-year average of cooling degree-days, heating degree-days, and humidity. The average home size forecast is a forward trend of the historical average home size in APS territory, which is weighted by the proportions of residential customers who live in single-family homes, apartments, or townhouses. Arizona personal income is forecast based on the historical relationship with Arizona total non-farm employment; the Arizona population forecast is used to put personal income into per-capita terms. Personal income is included to capture the effects of the business cycle on residential electricity usage. The real price of electricity is projected by including any known rate changes; otherwise, the real price is assumed constant over time.

Total projected annual residential electricity demand is the product of the projected average use per customer and the projected number of residential customers.

COMMERCIAL AND INDUSTRIAL CUSTOMERS LESS THAN 3 MW LOAD

The load forecast for the group of commercial and industrial customers with electric demand less than 3 MW is developed with a regression analysis of historical sales growth. A customer forecast is also produced, and the two together provide an implied use-per-customer forecast that serves as a useful diagnostic tool. The total class customer forecast is tied to the residential customer forecast in the long run and so anticipates the population and household growth explicitly accounted for in that forecast.

The regression analysis is a statistical multiple autoregressive regression model which estimates the historical relationship between total commercial and industrial electricity demand and overall economic growth in the APS Metro Phoenix service territory as measured by occupied commercial floor space. The regression model also includes variables for the real price of electricity and weather. The historical relationship is applied to a forecast of occupied commercial floor space to arrive at a projected electricity demand level for commercial and industrial customers. The forecast of occupied commercial floor space is tied to the population forecast described above via per capita occupied commercial floor space. Historical data on per capita occupied commercial floor space are derived from occupancy data reported by CoStar, a company that tracks commercial real estate in Arizona, and population estimates from the U.S. Census Bureau. The real price of electricity is projected by including any known rate changes; otherwise, the real price is assumed constant over time. As with the residential model, normal weather is defined as the average of the last 10 years.

Once the forecast for total commercial and industrial demand has been completed, the forecast for specific customers with load greater than 3 MW is subtracted from the total.

COMMERCIAL AND INDUSTRIAL CUSTOMERS GREATER THAN 3 MW LOAD

For customers with loads in excess of 3 MW, electricity demand forecasts are prepared individually. These forecasts are developed with input provided by customer account managers who are in routine communication with the customers and are knowledgeable about those customers' substantive near-term plans. In the absence of any additional information, these customers' loads are generally held constant in the outer years of the forecast. APS would be unlikely to find reliable independent causal variables to substitute for this method. No new customers are forecast for this group unless a specific new customer has been identified and it has been determined that the customer has a high probability of connecting to the system in the near future. Longer-term potential growth is captured in the econometric model of total commercial and industrial sales.

IRRIGATION AND STREET LIGHT CUSTOMER LOAD

The irrigation and street light classes represent two very small components of the APS load requirement. The number of irrigation accounts has declined substantially over the last couple of decades as population growth has driven the conversion of agricultural land into residential and commercial uses. Street light electricity demand typically grows in line with overall electricity demand reflecting the natural expansion in cities and towns. The electricity demand for each of these classes is projected by trending both the number of customers and the average use per customer in the class.

RESALE CUSTOMER LOAD

APS has sales contracts with a number of wholesale customers who are partial requirements customers. These customers are primarily electrical and irrigation districts located in western Maricopa County and in Pinal County whose main electricity demand comes from irrigation pumps within their territory. They are referred to as partial requirements because APS serves all of their electricity demand except for a portion which is supplied with federal hydroelectric preference power from the Colorado River and other similar sources. As a group, the districts' total electricity demand is neither expanding nor contracting. Year-to-year volatility emerges in the APS requirement due to changes in the availability of preference power from one year to the next. The load forecast assumes total demand for these customers remains constant through the term of their contracts, with adjustments for known or expected deviations in preference power included. This view is also informed by discussions with the customers. APS would be unlikely to find reliable independent causal variables to substitute for this method.

In addition to this electrical and irrigation district load, APS serves two requirements customers who each have residential and commercial customers in addition to pumping load. For these customers, the load obligation is either contractually determined or small and stable; the load forecast maintains these loads through the terms of their respective contracts.

LINE LOSSES

Transmission and distribution line losses coupled with company use are measured as the difference between the total amount of electricity generated or purchased to meet APS system demands and the total amount of electricity consumed by APS customers at the customer meter level. The most recent five-year average of these energy losses is about 6.5 percent.

OWN LOAD ENERGY

Own load energy is the summation of the class-level electricity demands plus energy losses.

RESPONSE TO RULES

SECTION D
SUPPLY

RESPONSE TO RULES SECTION D – SUPPLY

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(D), which specifically requires information related to system resources.

RULE D.1(A)

A 15-year resource plan, providing for each year: (a) Projected data for each of the items listed in subsection (B)(1), for each generating unit and purchased power source, including each generating unit that is expected to be new or refurbished during the period, which shall be designated as new or refurbished, as applicable, for the year of purchase or the period of refurbishment.

Projected data for each generating unit and purchased power resource is provided in the attachments referenced in Table D-1.

RULE D.1(B) – B.2(A)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(a): A description of generating unit commitment procedures.

APS optimizes the use of its resources to serve its customers in the most affordable manner possible, while maintaining grid reliability. The process begins by forecasting the load on a day-ahead basis. The load forecast is entered into a unit commitment and dispatch model (PCI GenTrader®/GenPortal®) that determines the most economic unit commitment plan for serving load, taking into account generating unit capabilities, intermittent resource production forecasts (e.g., wind and solar), fuel prices, contractual requirements, and transmission constraints. This commitment plan shows the units to be committed each hour, their projected loading level and the quantity of natural gas to be scheduled.

TABLE D-1. LIST OF D.1(A) ATTACHMENTS

PROJECTED DATA FOR GENERATING UNITS	ATTACHMENT
B.1(a) In service date and book life	D.1(a)(1)
B.1(b) Type of generating unit or contract	D.1(a)(1)
B.1(c) Share of generating unit capacity in MW	D.1(a)(1)
B.1(d) Maximum generating unit capacity	D.1(a)(1)
B.1(e) Annual capacity factor	D.1(a)(2)
B.1(f) Average heat rate	D.1(a)(3)
B.1(g) Average fuel cost Attachment	D.1(a)(4)
B.1(h) Other variable O&M Attachment	D.1(a)(1)
B.1(i) Purchased power energy costs -long-term contracts	D.1(a)(5)
B.1(j) Fixed O&M of generating units ($/MW)	D.1(a)(6)
B.1(k) Demand charges for purchased power	D.1(a)(7)
B.1(l) Fuel type for each generating unit	D.1(a)(1)
B.1(m) Minimum capacity	D.1(a)(1)
B.1(n) Whether the generating unit must run if available	D.1(a)(1)
B.1(o) Description of each generating unit	D.1(a)(1)
B.1(p) Environmental impacts – CO2	D.1(a)(8)
B.1(p) Environmental impacts – CO	D.1(a)(8)
B.1(p) Environmental impacts – VOC	D.1(a)(8)
B.1(p) Environmental impacts – NOx	D.1(a)(8)
B.1(p) Environmental impacts – SO2	D.1(a)(8)
B.1(p) Environmental impacts – Hg	D.1(a)(8)
B.1(p) Environmental impacts – PM	D.1(a)(8)
B.1(q) Water consumption quantities and rates	D.1(a)(8)
B.1(r) Tons of coal ash collected per unit (fly ash)	D.1(a)(8)
B.1(r) Tons of coal ash collected per unit (bottom ash)	D.1(a)(8)

As part of the process, the model calculates prices for blocks of energy to help determine if it would be cheaper to buy power from the market rather than to run generating units. The day-ahead trader compares these calculated block energy prices with actual power prices being offered in the market, then purchases either on-peak or off-peak blocks of energy, if economical. The model also calculates the breakeven price for making sales out of the Company's generating resources, after taking into account native load and any other pre-existing power sales commitments. If economical, the day-ahead trader will make power sales in the market.

The day-ahead commitment plan is turned over to the real-time operations team to take forward into the intraday markets. The real-time traders update the load and available resource forecasts and re-run the unit commitment and dispatch model to fine-tune the commitment plan. They also check the intraday market to make purchases and sales of power to further optimize the system.

Within the sub-hourly window, the real-time traders proceed to further refine the Company's generation plan by interacting with the CAISO Energy Imbalance Market (EIM) to transfer energy when economically beneficial to customers. Through calculated cost curves of each unit, the real-time traders determine which generators may be incremented, decremented, committed (start) and de-committed (shutdown) as part of a greater EIM footprint solution. While considering available transmission resources, fuel supplies, and reliability needs, APS participates in both the 5-minute and 15-minute markets while maintaining the NERC required reserves and system stability requirements. Each of these markets use dynamic meter and load data as well as 5-minute renewable forecasting to dispatch all participating units with the goal of reducing the production cost for APS customers and the greater EIM footprint.

As the final step in this process, the real-time traders issue the commitment instructions to generating units as needed to meet load and sales commitments. Additionally, they respond to dynamic changes by updating the plan as needed for generating unit or transmission outages and forecast updates; continuously optimizing usage of available resources.

For the duration of the Planning Period, the generating unit commitment procedures are not expected to change from one year to the next.

RULE D.1(B) – B.2(B)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(b): Production cost.

The production costs for the 15-year plan are provided in Table D-2**Error! Reference source not found.**. "Production Costs" (defined in R14-2-701(33)) include variable O&M costs of producing electricity through APS-owned generation. "Fuel" includes the commodity portion of fuel costs for APS-owned generating units to meet APS native load plus a long-term sales contract. "Emissions" refers to the costs associated with any CO2 emissions. "Purchases" includes the variable O&M and commodity portion of fuel costs for tolled generating units, costs for existing PPAs, and short-term market purchases represented in response to Rule D.1(b) – B.2(f). "Sales" that are shown as a negative value reflect revenue from a long-term wholesale sales contract that expires in 2020. "Sales" that are shown as a positive value reflect reliability sales.

TABLE D-2(1). TOTAL PRODUCTION COSTS FOR BRIDGE PORTFOLIO ($MILLIONS)

	Generation		Emissions	Purchases		Sales	Total
	FUEL	VARIABLE O&M	CO2	DEMAND	ENERGY		$MILLIONS
2020	408.6	59.7	0.0	81.8	258.0	(3.4)	804.7
2021	475.1	62.1	0.0	125.9	271.4	0.0	934.5
2022	457.0	63.3	0.0	130.7	276.6	0.1	927.6
2023	453.5	61.6	0.0	135.1	285.1	0.0	935.3
2024	477.4	66.1	0.0	135.4	282.2	0.6	961.6
2025	440.5	61.1	184.5	137.4	292.2	0.4	1,116.0
2026	430.0	67.0	177.5	144.2	280.9	0.1	1,099.8
2027	426.8	71.5	177.6	156.4	266.7	0.0	1,099.0
2028	471.0	79.4	195.4	122.2	263.7	4.3	1,136.0
2029	434.8	79.3	183.3	127.4	234.1	0.0	1,058.9
2030	456.8	83.7	191.9	134.5	240.6	6.7	1,114.2
2031	363.7	65.9	138.3	141.0	193.7	0.0	902.7
2032	306.9	62.6	107.4	146.4	174.3	0.0	797.6
2033	294.7	59.9	102.6	153.4	158.5	0.0	769.1
2034	293.5	61.7	103.0	159.0	146.8	0.1	764.1
2035	278.8	58.9	96.7	166.6	113.1	0.0	714.0

TABLE D-2(2). TOTAL PRODUCTION COSTS FOR SHIFT PORTFOLIO ($MILLIONS)

	Generation		Emissions	Purchases		Sales	Total
	FUEL	VARIABLE O&M	CO2	DEMAND	ENERGY		$MILLIONS
2020	408.3	59.8	0.0	81.8	257.9	(3.4)	804.4
2021	473.8	61.9	0.0	125.9	271.9	0.0	933.5
2022	456.7	63.3	0.0	130.7	276.6	0.1	927.3
2023	453.5	61.6	0.0	135.1	285.3	0.0	935.5
2024	477.1	66.2	0.0	133.3	282.4	0.5	959.6
2025	441.2	61.1	184.8	137.3	292.5	0.6	1,117.4
2026	429.9	67.0	177.5	144.2	281.0	0.1	1,099.7
2027	424.4	71.2	176.6	156.5	266.0	0.0	1,094.8
2028	460.1	76.5	189.1	123.1	261.6	1.7	1,112.1
2029	419.9	77.1	176.0	128.3	232.0	0.0	1,033.2
2030	453.8	82.8	189.6	133.9	228.7	4.7	1,093.6
2031	329.1	58.5	122.1	144.0	189.2	0.0	842.8
2032	261.6	51.9	86.8	150.4	168.1	0.0	718.8
2033	247.4	48.2	80.9	157.9	146.9	0.0	681.3
2034	239.9	47.9	78.0	164.2	129.8	0.0	659.8
2035	222.2	43.5	70.1	172.7	93.6	0.0	602.0

TABLE D-2(3). TOTAL PRODUCTION COSTS FOR ACCELERATE PORTFOLIO ($MILLIONS)

	Generation		Emissions	Purchases		Sales	Total
	FUEL	VARIABLE O&M	CO2	DEMAND	ENERGY		$MILLIONS
2020	408.4	59.8	0.0	81.8	257.7	(3.4)	804.4
2021	474.4	61.9	0.0	125.9	272.0	0.0	934.2
2022	456.5	63.2	0.0	130.7	277.1	0.1	927.6
2023	451.3	61.6	0.0	133.1	297.9	0.0	943.9
2024	474.5	65.0	0.0	133.2	305.4	0.5	978.6
2025	442.4	61.0	185.3	136.5	316.1	0.6	1,142.0
2026	408.3	62.0	169.2	104.5	304.4	0.0	1,048.3
2027	394.2	60.5	162.2	73.9	290.2	0.0	981.0
2028	423.6	65.6	172.8	39.5	280.7	0.4	982.6
2029	364.5	59.8	149.8	44.8	248.3	0.0	867.2
2030	423.5	68.5	173.6	45.3	238.3	2.3	951.4
2031	266.7	40.2	93.5	55.8	220.0	0.0	676.1
2032	182.1	27.4	51.2	62.2	199.4	0.0	522.4
2033	167.7	23.3	44.6	67.9	176.8	0.0	480.3
2034	157.5	20.8	40.1	72.6	159.0	0.0	449.9
2035	148.1	18.1	35.3	78.0	122.9	0.0	402.5

RULE D.1(B) – B.2(C)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(c): Reserve requirements.

The reserve requirements for the three portfolios presented in the 2020 IRP are provided in Attachment F.9(b)(1) – F.9(b)(3) on line 4 of each attachment.

RULE D.1(B) – B.2(D)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(c): Spinning reserve.

APS is one of 15 members of the Southwest Reserve Sharing Group (SRSG).[1] Individual members' spinning reserve requirements are calculated using a formula that takes into account factors such as each member's hourly loads, purchase and sale transactions, and thermal generation. Currently, APS's SRSG spinning reserve requirement is normally supplied by units fueled by natural gas, depending on economics. If APS was not an SRSG member, this requirement would increase to at least 560 MW to cover the system's largest single hazard. Because SRSG calculations are dependent upon each member's system conditions and the interaction of those systems working together, each member's contribution to SRSG spinning reserve may change over time.

Forecast spinning reserves over the planning horizon are illustrated in Table D-3. Half of these requirements can be met with units designed to start within 10 minutes.

[1] Additional information regarding SRSG can be found at www.srsg.org.

RULE D.1(B) – B.2(E)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(e): Reliability of generating, transmission, and distribution systems.

GENERATION RELIABILITY

Generation reliability of a resource plan is typically measured in terms of reserve margins or loss of load probabilities (LOLP). APS's reserve criterion is based on LOLP of one day of outage in ten years, which currently translates to a 15% reserve requirement. To ensure a reliable generation system, reserves should be greater than or equal to 15%. Table D-4 shows the annual reserve requirement amounts based on the 15% requirement (also shown on Attachment F.9(b), line 3).

TRANSMISSION AND DISTRIBUTION RELIABILITY

APS follows the Institute of Electrical and Electronics Engineers (IEEE) 1366 – 2012, "Guide for Electric Power Distribution Reliability Indices" for measuring reliability. Three of the most common indicators used for measuring reliability are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Momentary Average Interruption Frequency Index (MAIFI), and Customer Average Interruption Duration Index (CAIDI).

Forecasts for transmission and distribution reliability are provided in Attachment D.1(b). Transmission reliability represents projections of the portion of total SAIFI, SAIDI, MAIFI, and CAIDI, respectively, due to outages at the transmission level and illustrates a general flat trend in transmission reliability during the 15-year Planning Period with improvement over current reliability.

Distribution reliability represents projections of the portion of total SAIFI, SAIDI, MAIFI, and CAIDI, respectively, due to outages at the distribution level and illustrates a general improvement in APS's reliability. The improving effectiveness of current Reliability Programs with proactive and strategic approaches suggests slight improvements to reliability year over year. Forecast vs. actual data may vary depending upon weather patterns and unusual events.

As of 2018 new safety efforts have been put in place in response to fire mitigation. These new safety efforts have driven the reliability numbers, SAIFI, SAIDI, and CAIDI up in efforts to prevent wildfires during dry seasons.

TABLE D-3. FORECAST SPINNING RESERVE REQUIREMENT

2019	SPINNING RESERVE CAPACITY (MW)
January	309
February	254
March	211
April	227
May	242
June	244
July	263
August	266
September	244
October	220
November	243
December	214

TABLE D-4. FORECAST RESERVE REQUIREMENTS

YEAR	RESERVE REQUIREMENT
2020	1026
2021	1113
2022	1136
2023	1167
2024	1193
2025	1224
2026	1251
2027	1278
2028	1306
2029	1333
2030	1362
2031	1400
2032	1427
2033	1453
2034	1482
2035	1510

RULE D.1(B) – B.2(F)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(f): Purchase and sale prices, averaged by month, for the aggregate of all purchases and sales related to short-term contracts.

APS does not forecast specific short-term purchase or sales contracts in the 15-year forecast; however, APS does anticipate a certain level of short-term market purchases during the first five years as depicted in Attachment F.9(b) at line 32. These are assumed to be four-month summer purchases (June to September) with capacity and energy prices based on anticipated available market generation costs as indicated in Tables D-5(1) – D-5(3). These purchases provide added flexibility to the three portfolios presented in the 2020 IRP and may be procured a year at a time, if needed, in the year prior to the need.

TABLE D-5(1). COSTS OF FORECASTED SHORT-TERM MARKET PURCHASES – BRIDGE PORTFOLIO

YEAR	CAPACITY (MW)	DEMAND COST ($/KW-YR)	ENERGY COST ($/MWH)
2020	150	72.85	18.08
2021	237	74.67	25.46
2022	134	76.54	25.57
2023	50	78.45	26.08
2024	37	80.41	26.37

TABLE D-5(2). COSTS OF FORECASTED SHORT-TERM MARKET PURCHASES – SHIFT PORTFOLIO

YEAR	CAPACITY (MW)	DEMAND COST ($/KW-YR)	ENERGY COST ($/MWH)
2020	150	72.85	18.08
2021	237	74.67	25.46
2022	134	76.54	25.57
2023	50	78.45	26.08
2024	37	80.41	26.37

TABLE D-5(3). COSTS OF FORECASTED SHORT-TERM MARKET PURCHASES – ACCELERATE PORTFOLIO

YEAR	CAPACITY (MW)	DEMAND COST ($/KW-YR)	ENERGY COST ($/MWH)
2020	150	72.85	18.08
2021	237	74.67	25.46
2022	134	76.54	25.57
2023	25	78.45	26.08
2024	12	80.41	26.37

Notes: Currently there are no contracts in place for the capacity shown. The capacity is assumed to be available from June to September each year.
The demand costs are based on microgrid costs.
The energy costs are based on fuel and O&M costs for a peaking unit.

RULE D.1(B) – B.2(G)

A 15-year resource plan, providing for each year: (b) Projected data for each of the items listed in subsection (B)(2), for the power supply system. Rule B.2(g): Energy losses.

Energy losses for the 15-year forecast are provided in Attachment C.1(b) on the line labeled "Energy Losses".

RULE D.1(C)

A 15-year resource plan, providing for each year: (c) The capital cost, construction time, and construction spending schedule for each generating unit expected to be new or refurbished during the period.

Capital cost, construction time, and construction spending schedules are provided in Attachment D.1(c).

RULE D.1(D)

A 15-year resource plan, providing for each year: (d) The escalation levels assumed for each component of cost, such as, but not limited to, operating and maintenance, environmental compliance, system integration, backup capacity, and transmission delivery, for each generating unit and purchased power source.

The current estimate of future inflation is 2.5% per year, which is used for the escalation of capital, O&M and environmental compliance costs. Exceptions are: (1) fuel prices which are determined either through the forward market or contractual terms; (2) purchased power prices that are determined through contractual terms; (3) solar photovoltaic capital costs, which are expected to decline (in real terms) through 2029 as the technology matures, then escalate at the rate of inflation; and, (4) property taxes on generation and transmission resources which are assumed to escalate at 1% per year.

RULE D.1(E)

A 15-year resource plan, providing for each year: (e) If discontinuation, decommissioning, or mothballing of any power source or permanent derating of any generating facility is expected: (i) Identification of each power source or generating unit involved; (ii) The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating; and (iii) The reasons for discontinuation, decommissioning, mothballing, or derating.

(i) Identification of each power source or generating unit involved:

Four Corners Units 1-2-3 were retired December 31, 2013, Saguaro Steam Units 1-2 were retired June 30, 2013, and Ocotillo Steam Units 1-2 were retired March 22, 2019, and Cholla 2 was retired October 1, 2015. Cholla 1 & 3 will no longer burn coal past April 2025 and operations of Four Corners Units 4-5 will cease no later than 2031.

(ii) The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating

The cost to decommission Four Corners Units 1-3 was approximately $56 million. APS finished dismantling Units 1-3 in November 2016 and is not planning to fully decommission the site until after the retirement of Units 4-5.

The estimated cost to decommission the Saguaro Steam Units is approximately $9.0 M.

The estimated cost to decommission the Ocotillo Steam Units is approximately $8.0 M.

The estimated cost to decommission the Cholla 2 Steam Unit is approximately $8.2 M.

(iii) The reasons for discontinuing, decommissioning, or mothballing, or derating

The retirement of Four Corners Units 1-3 was part of a plan that included APS purchasing SCE's share of Four Corners 4-5. Details of that transaction are provided in Decision No. 73130[2]. Four Corners Units 1-3 were retired 1) so that APS ownership in coal would not increase appreciably as a result of the transaction, 2) to satisfy BART provisions with the EPA, and 3) APS does not have enough transmission to deliver its new share of Units 4-5 plus Units 1-3.

The Saguaro Steam Units were constructed in 1954 and 1955 and have reached the end of their useful life. The units are old, inefficient technology that had become increasingly difficult to maintain. APS anticipates preserving the site for remaining generation and for potential new generation in the future.

The Ocotillo Steam Units were installed in 1960 and have also reached the end of their useful lives. It had become increasingly difficult to maintain the units and acquire necessary parts for repair. Due to the importance of the location of the power plant in the Valley and its impact on ability to serve Valley load, new generating units were built on the site. Five fast start combustion turbines were built at Ocotillo and came on-line in 2019.

Cholla 2 Steam Unit was retired 1) due to the age of the unit, reaching the end of its useful life 2) potential capital cost associated with environment compliance and 3) the additional generation associated with the purchase of SCE's share of Four Corner Units 4-5.

Cholla 1 & 3 will no longer burn coal past April 2025; however, APS is continuing to evaluate its options related to Cholla and will inform the Commission upon making any decisions in this matter.

[2] ACC Decision No. 73130 (April 24, 2012)

The retirement of Four Corners Units 4-5 in 2031 is done so to meet the goal of ending APS's use of coal-fired generation as part of the APS clean energy commitment.

RULE D.1(F)

A 15-year resource plan, providing for each year: (f) The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period.

TRANSMISSION

A list of transmission projects which includes capital costs for new or refurbished transmission facilities is provided in Attachment D.1(f). O&M costs are not assigned to individual projects and are planned as a total of all projected transmission O&M during budgeting activities as shown in Table D-6. As new transmission facilities are added to the system, they are incorporated into normal activities per APS's various processes. The O&M costs shown are those associated with the newly added transmission facilities.

TABLE D-6. O&M COSTS FOR NEW OR REFURBISHED TRANSMISSION

YEAR	O&M ($000)
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]
2028	[redacted]
2029	[redacted]
2030	[redacted]
2031	[redacted]
2032	[redacted]
2033	[redacted]
2034	[redacted]
2035	[redacted]

DISTRIBUTION

APS plans its distribution system on a three-year basis. Because the dynamics of a distribution system are so heavily dependent on the level and location of electric load growth or reduction, forecasting with a high degree of accuracy beyond the three-year time frame is difficult and subject to the variations of economic activity. Also, distribution system improvements must be made in a very small geographic location so pinpointing exactly where the load changes will occur is problematic very far into the future. The forecasted expenditures for capital and O&M provided in the Table D-7 were developed based upon APS's past expenditures and its system coincident peak load forecast for 2020 to 2035. O&M costs are not assigned to individual projects and are planned as a total projected distribution O&M during budgeting activities. As new distribution facilities are added to the system, they are incorporated into normal activities per APS's various processes. The O&M costs shown are those associated with the newly added distribution facilities.

TABLE D-7. DISTRIBUTION PLANNED IMPROVEMENT EXPENDITURES

YEAR	Capital ($000)	O&M ($000)
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]

ADVANCED GRID TECHNOLOGY

APS is likely to invest $341M in new grid technologies through 2025 to support reliability, integrate distributed energy and emerging technologies. A list of technologies includes but is not limited to, Advanced Operational Platforms, Automated Switches, Communicating Fault Indicators, Advanced Analytics, Substation Health Monitors, Communication Infrastructure, Downed Conductor Detection, Advanced Metering Infrastructure, Phasor Measurement Units, and Network Protectors. These technologies are described in Chapter 3 Modernizing the Grid.

RULE D.1(G)

A 15-year resource plan, providing for each year: (g) An explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona.

An explanation of the need for and purpose of all expected new or refurbished transmission is provided in Attachment D.1(f)(1). The need and purpose of distribution facilities is discussed in response to D.1(f) above.

RULE D.1(H)

A 15-year resource plan, providing for each year: (h) Cost analyses and cost projections, including the cost of compliance with existing and expected environmental regulations.

Cost analyses and projections for the three portfolios presented in the 2020 IRP are provided in Attachment D.10. The cost of existing and expected environmental regulations is embedded within the capital, O&M and emissions figures.

RULE D.2

Documentation of the data, assumptions, and methods or models used to forecast production costs and power production for the 15-year resource plan, including the method by which the forecast was benchmarked.

PRODUCTION MODEL

Data and assumptions related to resource dispatch and O&M costs as well as other system assumptions are well documented in response to rule D.1(a) and D.1(b) above. APS utilized Energy Exemplar's AURORA to analyze the resource plans in the IRP. AURORA is an hourly (with sub-hourly capability) production cost model that optimizes the commitment and dispatch of existing and future resources on the APS system. AURORA is widely used across the industry and is continually enhanced for the evolving needs of electric utilities. Inputs to AURORA include hourly load, unit characteristics (including capacity, heat rates, startup energy costs and maintenance), fuel price, environmental and regional constraints, renewable shapes and transactions. AURORA has enhanced storage logic, enabling an efficient integration of energy storage on systems with large renewable penetrations. AURORA outputs hourly (or aggregated) system production cost, unit costs and operating statistics (startups, energy output, runtime, capacity factor, fuel consumption and cost, emission production and cost as well as variable and fixed O&M).

BENCHMARKS

APS benchmarks the production simulation against the Company's budgeting tool, which itself is reconciled with actual system operations and production costs on a monthly basis. One important difference between resource planning and budgeting is that resource planning does not model the interchange market, which changes significantly from one year to the next and over which APS has no control. Decisions are made to optimize resources within the Company's control to serve native load. In real-time, however, APS of course takes advantage of market opportunities for the benefit of customers.

ASSUMPTIONS

Data and system assumptions related to resource dispatch, fuel and O&M costs are thoroughly documented in the response to Rule D.1(a) and D.1(b). Resource capital costs are documented in the response to Rule D.3. Financial assumptions and emissions costs used to forecast production costs and power production for the three portfolios presented in the 2020 IRP are included in Table D-8, Table D-9, Table D-10 and Table D-11.

TABLE D-8. COST OF CAPITAL

	CAPITAL RATIO	COST RATE	WEIGHTED COST OF CAPITAL	AFTER-TAX WEIGHTED COST OF CAPITAL
Debt	44.20%	6.00%	2.65%	1.99%
Equity	55.80%	10.00%	5.58%	5.58%
Totals	100%		8.23%	7.57%
AFUDC Rate	7.15%			
Composite Income Tax Rate	24.80%			

TABLE D-9. DEPRECIATION

	BOOK LIFE	TAX LIFE
Coal	40 Years	20 Years
Small Modular Reactor	40 Years	15 Years
Combined Cycle	40 Years	20 Years
Combustion Turbine	40 Years	15 Years
Transmission	50 Years	15 Years
Solar	40 Years	5 Years
Wind	40 Years	5 Years
Geothermal	30 Years	5 Years
Biomass	30 Years	5 Years

TABLE D-10. INVESTMENT TAX CREDITS

	2020	2021	FUTURE YEARS
Solar	26.00%	22.00%	10.00%
Geothermal	10.00%	10.00%	10.00%

TABLE D-11. CARBON DIOXIDE COSTS

YEAR	CO2 COST ($/METRIC TON)
2020	$0.0
2021	$0.0
2022	$0.0
2023	$0.0
2024	$0.0
2025	$18.9
2026	$19.3
2027	$19.8
2028	$20.3
2029	$20.8
2030	$21.4
2031	$21.9
2032	$22.4
2033	$23.0
2034	$23.6
2035	$24.2

1. CO_2 numbers based on CA 2020 CO_2 cost escalated at 2.5% (begin in 2025).

RULE D.3

A description of each potential power source that was rejected; the capital costs, operating costs, and maintenance costs of each rejected source; and an explanation of the reasons for rejecting each source.

APS estimated the delivered cost of a broad spectrum of potential power sources, including conventional baseload, intermediate, peaking and energy storage resources as well as renewable solar, wind, geothermal and biomass/biogas resources. A number of those are represented in the three portfolios presented in the 2020 IRP based on resource need, economics, diversity, and operational characteristics. Attachment D.3 includes the description, capital costs, O&M costs, and performance characteristics for the resource technologies that were selected to be included in the three portfolios presented in the 2020 IRP as well as those technologies that were not selected.

In addition to these resources, APS is evaluating a wide range of energy storage and renewable options on an ongoing basis. These include, but are not limited to, flow batteries, compressed air storage, pumped storage, and solar thermal. At the time of the 2020 integrated resource plan these technologies are either economically or commercial infeasible. APS will continue to evaluate these and other resources option on an ongoing basis.

Actual power sources will be acquired through the competitive procurement process. Furthermore, actual power sources procured may be different than those currently represented in the plan.

TABLE D-12. RENEWABLE ENERGY CAPACITY AND PRODUCTION

YEAR	NAMEPLATE CAPACITY (MW)	ENERGY PRODUCTION (MWH)
2020	1,281	1,889,226
2021	1,368	2,030,508
2022	1,428	2,127,588
2023	1,503	2,247,753
2024	1,590	2,385,600
2025	1,685	2,537,540
2026	1,786	2,697,459
2027	1,892	2,865,642
2028	2,002	3,042,254
2029	2,116	3,224,812
2030	2,235	3,415,079
2031	2,353	3,603,281
2032	2,472	3,794,991
2033	2,592	3,985,771
2034	2,711	4,177,016
2035	2,830	4,368,029

RULE D.4

A 15-year forecast of self-generation by customers of the load-serving entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours).

The 15-year forecast of self-generation in terms of annual peak production (MW) is provided in Attachment F.9(b) on line 25 of the Loads & Resources table. The forecast of annual energy production (MWh) is provided in Attachment C.1(b) on the line labeled "Distributed Energy Programs."

RULE D.5

Disaggregation of the forecast of subsection (D)(4) into two components, one reflecting the self generation projected if no additional efforts are made to encourage self generation, and one reflecting the self generation projected to result from the load-serving entity's institution of additional forecasted self generation measures.

At this time, APS does not offer an up-front cash incentive for self-generation. The response provided in Rule D.4 depicts the current outlook for adoption of self-generation. The future of DE penetration is impacted by many factors and is therefore highly uncertain. See Table D-12 for the renewable energy capacity and production for the selected plan.

RULE D.6

A 15-year forecast of the annual capital costs and operating and maintenance costs of the self generation identified under subsections (D)(4) and (D)(5).

Error! Reference source not found. shows the forecast of total annual customer costs that may potentially be incurred by customer investments[3] in self-generation for the select plan during the 15-year Planning Period.

TABLE D-13. FORECAST OF ANNUAL SELF-GENERATION COST INCURRED BY APS CUSTOMERS FOR PORTFOLIOS (BRIDGE, SHIFT AND ACCELERATE)

	CAPITAL		O&M	
Year	**$M**	**$/Watt (ac)**	**$M**	**$/kW-yr (ac)**
2020	[redacted]			
2021	[redacted]			
2022	[redacted]			
2023	[redacted]			
2024	[redacted]			
2025	[redacted]			
2026	[redacted]			
2027	[redacted]			
2028	[redacted]			
2029	[redacted]			
2030	[redacted]			
2031	[redacted]			
2032	[redacted]			
2033	[redacted]			
2034	[redacted]			
2035	[redacted]			

RULE D.7

Documentation of the analysis of the self generation under subsections (D)(4) through (6).

The three portfolios of the 2020 Resource Plan reflect the estimation of the energy output reflected in this case. The response to D.4 estimates the projected level of self-generation in 2020 through 2035. The development of the D.4 forecast was based upon consultation with Guidehouse and in collaboration with the smaller IRP stakeholder team. The future of DE penetration remains robust in the APS service territory, and the Company will update its forecast as new information becomes available.

For each response given to Rules D.4 through D.6, APS assumes self-generation to be solely renewable-based. APS does not forecast the penetration of diesel- or natural gas-fired standby and emergency generation at this time.

[3] $/Watt represents the average cost between residential and commercial

RULE D.8

A plan that considers using a wide range of resources and promotes fuel and technology.

The three portfolios presented in the 2020 IRP employ a wide range of resources, both supply and demand side, and promotes fuel and technology diversity within the portfolio. On the supply side, the plan includes new renewable resources such as solar photovoltaic, wind, and biomass; a wide variety of energy efficiency and demand response measures; and, an evaluation of hydrogen capable combustion turbines. As illustrated in Figures 7-5, 7-6 and 7-7, found in Chapter 7, the three portfolios of the 2020 IRP reflect a significantly cleaner energy mix over current levels.

RULE D.9

A calculation of the benefits of generation using renewable energy resources.

The estimated benefits of renewable energy resources (including distributed energy as well as energy from renewable contracts and resources) are listed in Table D-14(1) – (3).

TABLE D-14(1). RENEWABLE ENERGY BENEFITS – BRIDGE PORTFOLIO

TOTAL RENEWABLE				AVOIDED EMISSIONS							
	Peak Capacity (MW)	Energy (GWh)	Avoided Gas Burn (BCF)	CO2 (Tons)	SO2 (Tons)	CO (Tons)	NOx (Tons)	PM10 (Tons)	HG (Lbs)	VOC (Tons)	Avoided Water Usage (Acre Feet)
2020	797	3,675	27	1,634,048	8	126	139	62	7	14	3,463
2021	803	3,781	28	1,680,982	8	129	143	63	7	14	3,562
2022	963	4,854	36	2,157,986	11	166	184	81	9	18	4,573
2023	1,299	6,184	46	2,749,443	14	211	234	104	12	23	5,826
2024	1,498	7,062	53	3,139,723	16	241	267	118	13	27	6,653
2025	2,104	9,624	72	4,278,603	22	329	364	161	18	36	9,067
2026	2,308	10,844	81	4,821,095	24	371	410	182	21	41	10,216
2027	2,538	12,150	91	5,401,912	27	415	460	204	23	46	11,447
2028	2,849	12,892	96	5,731,631	29	441	488	216	25	49	12,146
2029	3,026	14,265	107	6,342,109	32	487	539	239	27	54	13,440
2030	3,210	16,329	122	7,259,780	37	558	618	274	31	62	15,384
2031	3,672	17,954	134	7,982,415	40	614	679	301	34	68	16,916
2032	3,866	19,269	144	8,566,772	43	658	729	323	37	73	18,154
2033	4,032	20,771	155	9,234,731	47	710	786	348	40	79	19,569
2034	4,229	21,994	165	9,778,382	49	752	832	369	42	83	20,722
2035	4,452	23,539	176	10,465,255	53	804	890	395	45	89	22,177
		TOTAL	**1,533**	**91,224,867**	**460**	**7,012**	**7,762**	**3,440**	**391**	**776**	**193,315**

TABLE D-14(2). RENEWABLE ENERGY BENEFITS – SHIFT PORTFOLIO

	TOTAL RENEWABLE			AVOIDED EMISSIONS							
	Peak Capacity (MW)	Energy (GWh)	Avoided Gas Burn (BCF)	CO2 (Tons)	SO2 (Tons)	CO (Tons)	NOx (Tons)	PM10 (Tons)	HG (Lbs)	VOC (Tons)	Avoided Water Usage (Acre Feet)
2020	797	3,678	28	1,635,391	8	126	139	62	7	14	3,466
2021	803	3,780	28	1,680,459	8	129	143	63	7	14	3,561
2022	963	4,844	36	2,153,612	11	166	183	81	9	18	4,564
2023	1,299	6,184	46	2,749,271	14	211	234	104	12	23	5,826
2024	1,498	7,061	53	3,139,474	16	241	267	118	13	27	6,653
2025	2,076	9,319	70	4,143,186	21	318	352	156	18	35	8,780
2026	2,242	10,291	77	4,575,483	23	352	389	173	20	39	9,696
2027	2,449	11,211	84	4,984,507	25	383	424	188	21	42	10,563
2028	3,065	12,887	96	5,729,324	29	440	487	216	25	49	12,141
2029	3,211	14,153	106	6,292,252	32	484	535	237	27	54	13,334
2030	3,419	16,338	122	7,263,924	37	558	618	274	31	62	15,393
2031	4,096	19,164	143	8,520,392	43	655	725	321	37	73	18,056
2032	4,318	20,893	156	9,289,024	47	714	790	350	40	79	19,685
2033	4,477	22,491	168	9,999,499	50	769	851	377	43	85	21,190
2034	4,707	24,019	180	10,678,671	54	821	908	403	46	91	22,629
2035	4,949	26,023	195	11,569,564	58	889	984	436	50	99	24,517
		TOTAL	**1,588**	**94,404,033**	**476**	**7,256**	**8,029**	**3,559**	**406**	**804**	**200,054**

TABLE D-14(3). RENEWABLE ENERGY BENEFITS – ACCELERATE PORTFOLIO

	TOTAL RENEWABLE			AVOIDED EMISSIONS							
	Peak Capacity (MW)	Energy (GWh)	Avoided Gas Burn (BCF)	CO2 (Tons)	SO2 (Tons)	CO (Tons)	NOx (Tons)	PM10 (Tons)	HG (Lbs)	VOC (Tons)	Avoided Water Usage (Acre Feet)
2020	797	3,679	28	1,635,497	8	126	139	62	7	14	3,466
2021	803	3,781	28	1,680,995	8	129	143	63	7	14	3,562
2022	963	4,844	36	2,153,496	11	166	183	81	9	18	4,564
2023	1,299	6,186	46	2,750,144	14	211	234	104	12	23	5,828
2024	1,498	6,984	52	3,104,838	16	239	264	117	13	26	6,580
2025	2,123	9,381	70	4,170,532	21	321	355	157	18	36	8,838
2026	2,792	12,010	90	5,339,511	27	410	454	201	23	45	11,315
2027	3,359	14,208	106	6,316,830	32	486	537	238	27	54	13,386
2028	3,833	15,030	112	6,682,463	34	514	568	252	29	57	14,161
2029	3,980	17,648	132	7,846,218	40	603	667	296	34	67	16,627
2030	4,238	18,617	139	8,276,850	42	636	704	312	36	71	17,540
2031	4,868	23,427	175	10,415,417	53	801	886	393	45	89	22,071
2032	5,073	26,373	197	11,725,131	59	901	997	442	50	100	24,847
2033	5,304	28,215	211	12,544,062	63	964	1,067	473	54	107	26,582
2034	5,478	29,902	224	13,294,109	67	1,022	1,131	502	57	113	28,172
2035	5,692	31,379	235	13,950,754	70	1,072	1,187	526	60	119	29,563
		TOTAL	**1,881**	**111,886,847**	**565**	**8,601**	**9,516**	**4,219**	**481**	**953**	**237,102**

RULE D.10

A plan that factors in the delivered cost of all resource options, including costs associated with environmental compliance, system integration, backup capacity, and transmission delivery.

Revenue requirements for the three portfolios presented in the 2020 IRP are shown in Attachment D.10 and include the delivered costs of all the resource options as described above.

The attached revenue requirements reflect the annual revenue level required to supply APS customers' energy needs, including: (1) carrying costs on existing and future generation, future transmission over and above APS Ten Year Transmission Plan, and capital expenditures on existing generation; (2) fuel costs (commodity and fixed transport); (3) purchase power costs; (4) operating and maintenance costs for existing and future generation; (5) energy efficiency and distributed energy program and incentive costs; and, (6) power plant emission costs including CO2. Revenue requirements as used in the IRP do not include costs associated with existing transmission, existing and future distribution, or sales tax on retail electric sales.

Environmental compliance costs are embedded within the capital and O&M figures, and system integration costs are embedded in the purchased power costs for solar photovoltaic and wind technologies. The loads and resources plan factors in backup capacity and those costs are included within the total revenue requirement costs.

RULE D.11

Analysis of integration costs for intermittent resources.

System integration costs may be incurred by operation of some non-dispatchable resources such as wind or solar due to their variable nature. Additional operating reserves may need to be carried on the rest of the system to effectively follow APS load and meet NERC reliability requirements. System integration costs depend upon many factors, including the accuracy of forecasted intermittent generation, real-time generation fluctuation, renewable penetration levels and resource mix. In the beginning of 2020, APS commissioned Energy Exemplar to conduct both the Solar Photovoltaic (PV) and Wind integration cost studies to assess the additional costs for integrating intermittent resources into APS's generation portfolio. The results of this study were incorporated into the 2020 IRP and are further detailed in Chapter 2.

RULE D.12

A plan to increase the efficiency of the load-serving entity's generation using fossil fuel.

APS operates and maintains the fleet of generating units to optimize efficiency by balancing expenditures with benefits achieved by those expenditures. Opportunities to increase unit efficiency are evaluated on a regular basis from both economic justification and environmental permitting perspectives.

APS's objective is to ensure unit reliability is maintained so that the units are available to meet the load demand. O&M and capital expenditures are planned to maximize equipment reliability, thus reducing the amount of time the units are unavailable due to equipment failures. For baseload units, this reduces fuel costs that are incurred during unplanned startups and shutdowns. In addition, proper and timely maintenance reduces replacement power costs that can be incurred during forced outage events.

Plant components are maintained with the objective of meeting the original design performance specifications. When O&M expenditures to maintain the equipment become too high or the component condition is showing signs of degradation that may threaten unit reliability, the component will be evaluated for replacement. In these circumstances, the component will be evaluated for any changes that can be made that will result in improved unit efficiency. This evaluation considers environmental permit impacts to ensure compliance with regulatory requirements.

APS also increases the efficiency of its fossil generation fleet by its resource decisions going forward. When APS added new natural gas generation to its system in 2019, it added generation that is more efficient than previous models. The existing Ocotillo Steam units had full load heat rates of about 10,500 Btu/kWh, and in the modernization project, they were replaced with state-of-the-art LMS100 combustion turbines expected to have heat rates of approximately 9,100 Btu/kWh. This will significantly increase the efficiency of the site and of APS generation portfolio in general.

Another aspect of efficiency applies to water consumption. APS has announced clean energy goals that will increase reliance on renewable energy such as PV solar and wind generation and on increased energy efficiency programs. Energy efficiency and wind generation consume no water, while photovoltaic solar has very low consumption rates. APS is also investing significantly in battery storage technologies that will reduce the need for peak generation from combustion turbines, further reducing fleet water intensity. A forecast of the reduction in water intensity measured as gallons per MWh for the Resource Plan is included in the response to Rule D.17.

RULE D.13

Data to support technology choices for supply-side resources.

Data to support technology choices for supply-side resources has been provided in Attachment D.3.

RULE D.14(A)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (a) How and when the program or measure will be implemented

CURRENT PROGRAMS

There are currently eleven EE programs and twenty-seven DR programs and initiatives (including eighteen rates). This included eighteen residential programs and twenty non-residential programs. These programs are detailed in Attachment D.14(a).

FUTURE PROGRAMS

The Company will continue to evaluate existing and emerging technologies and measures to identify cost-effective programs that align with long-term resource planning needs. Because of the rapid advance in distributed energy technologies and products, constant evaluation is required. When new, unproven measures or technologies are identified, APS may request approval of new programs, measures, or pilots to assist APS in quantifying the resource potential to support future resource planning needs, as well as assist in refining the resource cost-effectiveness calculations. Through pilots, APS will be able to gather data regarding the societal and program costs and benefits that can then be used to more accurately depict the program cost-effectiveness and viability. APS has currently proposed and/or is currently implementing a number of innovative new DSM technology pilots and programs including Energy Storage and Load Management program (currently being implemented as the APS Rewards Program), Electric Vehicle Load Management, Reverse Demand Response, Advanced Water Heating Controls, Beneficial Electrification.

In planning for the future, APS applies the concepts described in Chapter 2 to develop its long-term DSM plans for the 2021-2035 period. APS developed long-term DSM goals while balancing the benefits and costs of DSM under various perspectives reflected in the context of the SC and RIM test. In this IRP, it is assumed that APS will continue its current portfolio of programs that are currently estimated to reduce system energy by approximately 706,708 MWh a year and provide 263 MWs per year in peak demand savings; while also adding incremental peak capacity from both Residential and Commercial/Industrial demand response during the Planning Period. APS commits to continue work with stakeholders to develop strategies and programs for future DSM. For details on DSM program additions in each proposed portfolio, refer to Chapter 7 and D.14(c) of this section.

TABLE D-15(1). RENEWABLE ENERGY BENEFITS – BRIDGE PORTFOLIO

	Peak Demand Reduction (MW)			Energy Reduction/Shifting (MWh)		
YEAR	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING
2020	105	21	0	224,336	1,890	0
2021	189	62	0	410,711	5,580	0
2022	274	75	0	597,086	6,750	0
2023	357	87	0	783,461	7,830	0
2024	439	100	0	969,836	9,000	0
2025	486	137	0	1,156,211	12,330	0
2026	567	149	0	1,342,586	13,410	0
2027	644	162	0	1,528,961	14,580	0
2028	726	174	0	1,715,336	15,660	0
2029	814	212	0	1,901,711	19,080	0
2030	890	224	0	2,088,086	20,160	0
2031	922	262	0	2,274,461	23,580	0
2032	991	274	0	2,460,836	24,660	0
2033	1,064	312	0	2,647,211	28,080	0
2034	1,133	324	0	2,833,586	29,160	0
2035	1,207	337	0	3,019,961	30,330	0

TABLE D-15(2). RENEWABLE ENERGY BENEFITS – SHIFT PORTFOLIO

	Peak Demand Reduction (MW)			Energy Reduction/Shifting (MWh)		
YEAR	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING
2020	105	21	0	224,336	1,890	0
2021	189	62	0	410,711	5,580	0
2022	274	75	0	597,086	6,750	0
2023	357	87	0	783,461	7,830	0
2024	439	100	0	969,836	9,000	0
2025	486	137	0	1,156,211	12,330	0
2026	567	149	0	1,342,586	13,410	0
2027	644	162	0	1,528,961	14,580	0
2028	726	174	0	1,715,336	15,660	0
2029	814	237	0	1,901,711	21,330	0
2030	890	249	0	2,088,086	22,410	0
2031	922	287	0	2,274,461	25,830	0
2032	991	299	0	2,460,836	26,910	0
2033	1,064	337	0	2,647,211	30,330	0
2034	1,133	349	0	2,833,586	31,410	0
2035	1,207	387	0	3,019,961	34,830	0

TABLE D-15(3). RENEWABLE ENERGY BENEFITS – ACCELERATE PORTFOLIO

	Peak Demand Reduction (MW)			Energy Reduction/Shifting (MWh)		
YEAR	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING	ENERGY EFFICIENCY	DEMAND RESPONSE	LOAD SHIFTING
2020	105	21	0	224,336	1,890	0
2021	189	62	0	410,711	5,580	0
2022	274	75	0	597,086	6,750	0
2023	357	87	0	783,461	7,830	0
2024	439	100	0	969,836	9,000	0
2025	486	137	0	1,156,211	12,330	0
2026	567	149	0	1,342,586	13,410	0
2027	644	162	0	1,528,961	14,580	0
2028	726	174	0	1,715,336	15,660	0
2029	814	212	0	1,901,711	19,080	0
2030	890	224	0	2,088,086	20,160	0
2031	922	262	0	2,274,461	23,580	0
2032	991	274	0	2,460,836	24,660	0
2033	1,064	312	0	2,647,211	28,080	0
2034	1,133	324	0	2,833,586	29,160	0
2035	1,207	337	0	3,019,961	30,330	0

RULE D.14(B)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (b) The projected participation level by customer class for the program or measure.

The projected participation level by customer class for energy efficiency programs and measures is extremely difficult to quantify due to the characteristics and nature of the program in question. As these programs may not exist 15 years into the future, or their components may be markedly different, projecting customer participation is not currently feasible. However, APS does estimate the number of measures installed needed to be undertaken to meet its goal for each year on a going-forward basis in the DSM Implementation Plan. Actual 2019 participation on a measure level is provided at Attachment D.14(b).

Projected demand response and time-of-use program participation is forecast in Table D-16 and Table D-17.

TABLE D-16. EXPECTED RESIDENTIAL DR PROGRAM PARTICIPATION

2020 RESIDENTIAL DR PROGRAMS		
Time-Differentiated Rates	Expected Participants	
	2020*	15 Year Horizon
1. ET-1 Time Advantage (9am -9pm)[1]	9,005	0
2. ET-2 Time Advantage (Noon - 7pm)1	33,986	0
3. ECT-1R Combined Advantage (9am-9pm)[1]	513	0
4. ECT-2 Combined Advantage (Noon - 7pm)[1]	2,755	0
5. R-2 (3pm – 8pm)	70,297	95,156
6. R-3 (3pm – 8pm)	167,115	226,212
7. R-TECH (3pm – 8pm)	36	49
8. R-TOUE-E (3pm – 8pm)	387,516	524,554
9. Peak Event Pricing[2]	240	Unknown
10. Demand Response, Energy Storage, Load Management Program[3]	40,000	Unknown

Notes:
1. APS has filed a request to freeze and limit this rate to only existing customers on the rate with distributed generation effective July 1, 2017 in ACC Docket E-01345A-16-0036.
2. Customers are included in the parent rate schedule.
3. Customers specific to the Cool Rewards, smart thermostat DR portion of the program. Other "Rewards" programs include Storage Rewards (battery storage), Reserve Rewards (water heaters).
*Total average participants as of December 2019

TABLE D-17. EXPECTED NON-RESIDENTIAL DR PROGRAM PARTICIPATION

2020 NON-RESIDENTIAL DR PROGRAMS		
Time-Differentiated Rates	Expected Participants	
	2020*	15 Year Horizon
1. E-20	377	0
2. E-32 XS TOU, E-32 S TOU, E-32 M TOU, E-32 L TOU	705	864
3. E-35	28	28
4. GS-Schools M, GS-Schools L	139	155
5. Interruptible Rate	0	Unknown
6. Peak Solutions[1]	425	N/A

Notes:
1. The underlying contract that supports this program expires at the end of 2024.
*Total average participants as of December 2019

As more cost-effective DSM measures and technologies are identified and new programs such as load management, energy storage, and other innovative new pilots are evaluated and deployed, additional customer participation over time is likely. All new programs and/or pilots will estimate identifying long-term customer participation and revised customer offsets per event. As more information becomes available, estimated participation numbers will be included in the APS DSM Implementation Plan filings.

RULE D.14(C)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (c) The expected change in peak demand and energy consumption resulting from the program or measure.

Depicted in Table D-18 are the capacity and annual energy savings for 2019 energy efficiency programs. As related in response to Rule D.14(b), projecting a programmatic breakdown out 15 years into the future is not currently feasible; however, Attachments C.1(a) and C.1(b) provide annual aggregate capacity and energy savings forecasts.

Projections of future demand response and time-of-use impacts are located in Table D-19. The savings represented in the three portfolios of the 2020 Resource Plan reflect the 2019 EE and DR program results.

TABLE D-18. ENERGY EFFICIENCY CAPACITY AND ENERGY CONRIBUTIONS

2019 Residential and Non-Residential EE Programs[1]		
PROGRAM NAME	**CAPACITY SAVINGS (MW)**	**ANNUAL ENERGY SAVINGS (MWH)**
Residential		
Existing Homes	52.1	24,313
New Construction	13.6	23,996
Conservation Behavior	24	39,325
Multi-Family	1.1	5,640
Limited Income	1.2	2,375
Residential Sub-Total	**92.0**	**95,649**
Non-Residential		
Existing Facilities	8.5	31,310
New Construction & Major Renovation	2.2	7,095
Energy Information Services	4.3	4134
Schools	1.7	9,369
Managed EV Charging Pilot	0.0	0
Non-Residential Sub-Total	**16.7**	**51,908**
Codes & Standards	5.0	18,634
System Savings	0	5,160
Rewards	27.4	120,029
DR Contribution	51.3	224,581
Energy and Demand Education	0.0	0
TOTAL	**192.40**	**515,961**

Notes:
1. Numbers represent peak demand and energy reduction goals, with DR contribution, for 2019 as reported in the APS DSM Annual Progress Report filed with the ACC on February 28, 2020.

TABLE D-19. EXPECTED DR PROGRAM ENERGY AND DEMAND CONTRIBUTIONS

2020 Residential and Non-Residential DR Programs								
PROGRAM NAME	2020		15-YEAR HORIZON					
			Bridge Portfolio		Shift Portfolio		Accelerated Portfolio	
	PEAK DEMAND REDUCTION (MW)	ANNUAL ENERGY REDUCTION (MWH)	PEAK DEMAND REDUCTION (MW)	ANNUAL ENERGY REDUCTION (MWH)	PEAK DEMAND REDUCTION (MW)	ANNUAL ENERGY REDUCTION (MWH)	PEAK DEMAND REDUCTION (MW)	ANNUAL ENERGY REDUCTION (MWH)
Residential								
Future Direct Load Control	76	N/A	116	N/A	116	N/A	116	N/A
Non-Residential								
Peak Solutions [2]	25	N/A	75	N/A	75	N/A	75	N/A
Unspecified Future Programs	N/A	N/A	330	N/A	355	N/A	380	N/A
Time-of-Use Rates [3]	117	75	N/A	N/A	N/A	N/A	N/A	N/A

Notes:
1. Per ACC Decision No. 76313, the credit for demand response and load management peak reductions are calculated as follows for energy savings: Energy Savings (MWh) = Load reductions MW x 8,760 x 50% load factor.
2. Expires prior to the end of the Planning Period. APS is Currently conducting an RFP process seeking increased Peak Solutions program capacity from 2021-2025.
3. Demand reductions are estimated for all current residential rates, and energy reduction is estimated only for ET-SP, CPP-RES and PTR. APS has not at this time completed energy reduction analyses for the remaining residential rates, and has not conducted energy or demand reduction analyses for the non-residential rates.

RULE D.14(D)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (d) The expected reductions in environmental impacts including air emissions, solid waste, and water consumption attributable to the program or measure.

EE programs as well as APS's non-residential load control and demand response pricing programs are all assumed to displace natural gas-fired generation. Because DR programs are designed to reduce only the top 1-2% of hours in the year, their direct impact on emissions is very small compared to EE programs that encompass more hours. However, DR and other flexible distributed capacity programs are becoming increasingly important to align energy demand with intermittent renewable resources when they are available and allow greater quantities of renewable energy to be integrated onto the grid. This indirectly helps to reduce overall emissions intensity.

Table D-20 provides estimates of 2019 energy efficiency environmental impacts. The estimated impacts on air emissions for the experimental residential peak event pricing programs and demand rates are shown in Table D-21.

TABLE D-20. EE ESTIMATED ENVIRONMENTAL IMPACT

2019 Residential and Non-Residential EE Programs Reduction of Environmental Impact[1]					
	WATER (MIL GAL)	SOX (LBS)	NOX (LBS)	CO2 (MIL LBS)	PM10 (LBS)
Residential					
Existing Homes	85	1,199	20,018	237	8,930
New Construction	130	1,828	30,508	361	13,609
Conservation Behavior	13	177	2,953	35	1,317
Multi Family	30	427	7,122	84	3,177
Limited Income	14	192	3,211	38	1,433
TOTAL - Residential	**272**	**3,824**	**63,812**	**755**	**28,465**
Non-Residential					
Existing Facilities	158	2,217	37,005	438	16,507
New Construction & Major Renovation	42	588	9,806	116	4,374
Energy Information Services	7	93	1,552	18	692
Schools	44	617	10,302	122	4,595
Managed EV Charging Pilot	-	-	-	-	-
TOTAL – Non-Residential	**250**	**3,515**	**58,665**	**694**	**26,169**

Notes:
1. Based on lifetime MWh savings

TABLE D-21. ESTIMATED ENVIRONMENTAL IMPACT FROM SELECT RATES AND PEAK SOLUTIONS

2020 Residential Peak Event Pricing Programs and Demand Rates Estimated Reduction in Air Emissions					
	WATER (MIL GAL)	SOX (LBS)	NOX (LBS)	CO2 (MIL LBS)	PM10 (LBS)
Peak Event Pricing	0.68	9.60	160.2	1.90	71.5
ECT-1R	0.40	5.64	94.1	1.11	42.0
ECT-2	0.41	5.78	96.5	1.14	43.1
R-2	24.54	345.11	5,759.5	68.18	2,569.1
R-3	71.56	1,006.36	16,795.1	198.81	7,491.8
R-TECH	-	-	-	-	-
Peak Solutions	35.04	492.75	8,223.5	97.35	3,668.3
TOTAL	132.6	1,865.2	31,128.9	368.5	13,885.7

RULE D.14(E)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (e) The expected societal benefits, societal costs, and cost-effectiveness of the program or measure.

All DSM programs implemented must be proven cost-effective through the societal benefit-cost test (SCT). The SCT is structurally similar to the Total Resource Cost Test (TRC) but goes beyond the TRC test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers).

In Decision No. 73089, APS was ordered "that in all future DSM Implementation Plans, the Company use the same input values and methodology as Staff for calculating the present value benefits and costs to determine benefit-cost ratios."

Table D-22 provides details on the societal benefits, societal costs, and cost-effectiveness of the existing DSM programs.

TABLE D-22. BENEFIT-COST RATIOS FOR EE PROGRAMS

2019 Residential and Non-Residential EE Programs Societal Costs, Benefits and Cost-Effectiveness				
	SOCIETAL BENEFITS ($1,000S)	SOCIETAL COSTS ($1,000S)	NET BENEFITS ($1,000S)	BENEFIT-COST RATIO
Residential				
Existing Homes	$7,660	$5,344	$2,316	1.43
New Construction	$15,922	$13,462	$2,460	1.18
Conservation Behavior	$592	$644	($52)	0.92
Multi Family	1,838	$1,896	($58)	0.97
Limited Income	$1,360	$1,360	$0	1.00
TOTAL- Residential	**$27,372**	**$22,706**	**$4,666**	**1.21**
Non-Residential				
Existing Facilities	$10,388	$10,123	$265	1.03
New Construction & Major Renovation	$2,802	$2,154	$648	1.30
Energy Information Systems	$623	$318	$305	1.96
Schools	$2,503	$2,332	$171	1.07
Schools EV Pilot	$0	$0	$0	0.00
Managed EV Charging Pilot	$0	$0	$0	0.00
TOTAL - Non-Residential	**$16,316**	**$14,927**	**$1,389**	**1.09**

The societal benefits, societal costs and cost-effectiveness of future demand response programs are currently not known, as those programs have yet to be developed. Time-of-Use pricing programs are inherently designed to be revenue neutral. The societal benefits, societal costs and cost-effectiveness of APS's non-residential load management program, Peak Solutions, can be found in Table D-23.

TABLE D-23. APS PEAK SOLUTIONS COST-BENEFIT RATIO

APS Peak Solutions Program Societal Costs, Benefits and Cost-Effectiveness				
	SOCIETAL BENEFITS ($1,000S)	SOCIETAL COSTS ($1,000S)	NET BENEFITS ($1,000S)	BENEFIT-COST RATIO
Rewards Program	N/A	N/A	N/A	N/A
APS Peak Solutions Program [1]	72,186	52,987	19,198	1.36

Note:
1. APS Peak Solutions societal costs, benefits and cost-effectiveness based on most recent analysis. APS is currently conducting an RFP process seeking increased Peak Solutions program capacity from 2021-2025.

TABLE D-24. EXPECTED LIFE OF EE PROGRAMS

2019 Residential and Non-Residential EE Programs Program and Measure Life	
PROGRAM	**YEARS**
Residential	
1. Existing Homes	11.0
2. New Construction	16.9
3. Conservation Behavior	1.0
4. Multi Family	16.8
5. Limited Income	18.0
Non-Residential	
1. Existing Facilities	15.7
2. New Construction & Major Renovation	18.4
3. Energy Information Systems	5.0
4. Schools	14.6

TABLE D-25. EE PROGRAM COSTS

2019 Residential and Non-Residential EE Programs [1] Program Costs	
PROGRAM	**COST ($1,000S)**
Residential	
1. Existing Homes	3,328
2. New Construction	2,792
3. Conservation Behavior	644
4. Multi Family	1,164
5. Limited Income	3,692
TOTAL:	**11,620**
Non-Residential	
1. Existing Facilities	3678
2. New Construction & Major Renovation	792
3. Energy Information Systems	224
4. Schools	995
5. Managed EV Charging Pilot	-
TOTAL:	**5,689**
DSM Initiatives	
1. Energy Storage and Load Management - Rewards program	3,191
2. Codes & Standards	19
3. Energy and Demand Education Pilot	3,104
TOTAL:	**6,314**

Note:
1. MER costs were an additional $2,172,757

RULE D.14(F)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (f) The expected life of the measure.

Demand response pricing programs do not have a "measure life"; however, the established rate plans are expected to be in place throughout the Planning Period. The APS Peak Solutions program has been contracted through 2024. Table D-24 presents the estimated measure life (in years) by EE program.

RULE D.14(G)

A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure: (g) The expected life of the measure.

The estimated costs for EE programs are included in Table D-25.

The APS Peak Solutions program is administered through a contract with a third-party provider (currently contracted through 2024) that includes both energy and capacity payments. The expected program costs through the term of the Peak Solutions contract can be found in the Table 26. In 2019, more than 100% of the capacity reduction contracted for was achieved.

TABLE D-26. FORECASTED COSTS FOR APS PEAK

Peak Solutions Program Costs	
YEAR	**COSTS [1] ($1,000S)**
2020	[redacted]
2021	
2022	
2023	
2024	

Note:
1. APS is currently conducting an RFP process seeking increased Peak Solutions program capacity from 2021-2025, which will likely change future program costs.

Capital and O&M costs for potential customer load management and generation programs such as residential direct load control, thermal energy storage, or standby generation have been estimated in the Company's 2008 Demand Response Study. APS is currently conducting an RFP process to seek bids for additional C&I demand response program capacity from 2021 through 2025.

RULE D.15

For each demand management measure that was considered but rejected: (a) A description of the measure; (b) The estimated change in peak demand and energy consumption from the measure; (c) The estimated cost-effectiveness of the measure; (d) The capital costs, operating costs and maintenance costs of the measure, and the program costs; and, (e) The reasons for rejecting the measure.

As required by the EE Rules, the societal cost test was applied to all measures submitted for approval by APS. If the benefit-cost ratio was not greater than 1.0, the measure was rejected. Table D-27 details the response to Rules D.15(a) through D.15(d) for the EE measures that were considered but rejected. In response to D.15(e), all of the measures listed were not approved due to their not passing the SCT requirement. APS will continue to reevaluate beneficial measures and propose those that improve the DSM portfolio in subsequent DSM filings.

DEMAND RESPONSE PROGRAMS

To date, no specific DR program has been rejected.

TABLE D-27. REJECTED EE MEASURES AND PROGRAMS

Residential and Non-Residential EE Programs - Rejected Measures and Programs				
RULE D.15(A)	RULE D.15(B)		RULE D.15(C)	RULE D.15(D)
DESCRIPTION	PEAK DEMAND SAVINGS (KW/UNIT)	ENERGY SAVINGS (KWH/UNIT)	ESTIMATED COST-EFFECTIVENESS (SCT RESULT)	INCREMENTAL MEASURE COST ($/UNIT)
Residential				
Clothes Washer Tier 1 (existing)(1)	0.02	163	0.20	$301.20
Clothes Washer Tier 2 (existing)	0.03	202	0.40	$364.46
Clothes Washer Tier 3 (existing)	0.03	232	0.50	$427.72
Clothes Washer Advanced (proposed)(2)	0.04	280	0.70	$467.33
Dishwashers	0.07	13	0.04	$99.66
Energy Star Refrigerators	0.06	243	0.90	$131.00
Window Film	0.28	527	0.80	$537.00
Solar Water Heaters	0.40	2,950	0.25	$4,000.00
Smart Strips	0.04	208	0.95	$22.49
In-Unit Linear Fluorescents	0.03	17	0.27	$23.95
Advanced Diagnostic Tune-Up (Per HVAC unit)	0.42	583	0.96	$127.05
Smart Homes (Smart thermostat + Smart DHW control) - (Per home)	2.57	1213	0.87	$774.45
Smart Homes - RNC (Per home)	1.39	918	0.62	$636.08
Shade Screens (Per sqft)	0.00	4	0.71	$4.18
Variable Speed HVAC (Per Ton)	0.48	672	0.32	$1,262.50

TABLE D-27. REJECTED EE MEASURES AND PROGRAMS (CONTINUED)

Residential and Non-Residential EE Programs - Rejected Measures and Programs				
RULE D.15(A)	RULE D.15(B)		RULE D.15(C)	RULE D.15(D)
DESCRIPTION	PEAK DEMAND SAVINGS (KW/UNIT)	ENERGY SAVINGS (KWH/UNIT)	ESTIMATED COST-EFFECTIVENESS (SCT RESULT)	INCREMENTAL MEASURE COST ($/UNIT)
Non-Residential				
T12 to Premium T8 ad Electronic Ballast - 8 foot	-	16	0.68	$10.24
HID to 2-lamp T5HO	0.11	359	0.82	$195.69
HID to 3-lamp T5HO	0.15	466	0.94	$223.69
HID to 6-lamp T5HO	0.14	448	0.80	$251.33
Motor Rewind	-	19	0.89	$305.00
Night Covers	-	235	0.72	$40.52
High-Efficiency Ice Makers	0.24	1787	0.83	$665.88
T8 to Premium T8	0.01	67	0.53	$58.31
T12 to T8	0.04	210	0.92	$57.36
Evaporative Fan Motor Controls	-	493	0.53	$245.83
Smart Strips	0.06	182	0.56	$79.00
LED Channel Signs	0.01	26	0.60	$10.10
Bid for Efficiency	-	1	0.78	$0.33
LED - Pedestrian Signs	0.10	705	0.88	$238.66
LED Troffers	0.08	299	0.59	$296.03
Coolerado	0.07	137	0.08	$1,100.00
Solar Water Heaters	0.42	3069	0.26	$4,000.00
MultiStageEvaporativeCoolers (Per Ton)	0.07	176	0.91	$100.83
Occupancy Sensors (PER WATT)	0.00	1	0.80	$0.29
Advanced Diag Tune up (PER UNIT)	0.45	1182	0.74	$12.19
Outside Air Economizer (PER TON)	0.00	272	0.70	$80.00
HID to 3-lamp T5HO (PER FIXTURE)	0.09	465	0.68	$223.69
HID to 2-lamp T5HO (PER FIXTURE)	0.07	358	0.59	$195.69
Continuous RCx (Per Sq. ft.)	0.00	2	0.55	$2.02
T12 to Premium T8 and Electronic Ballast 4-foot (PER LAMP)	0.00	23	0.53	$14.18
T8 to T8 premium (PER FIXTURE_DI)	0.02	85	0.49	$56.84
T12 to Premium T8 and Electronic Ballast 2-foot (PER LAMP)	0.00	15	0.40	$12.38
Coin Operated Laudry (PER MACHINE)	0.16	717	0.36	$525.71
High Efficiency Battery Charger (Per Charger)	0.45	2001	0.31	$1,579.10
T12 to Premium T8 and Electronic Ballast 8-foot (PER LAMP)	0.00	9	0.17	$17.44
Advanced Diag Tune up (PER UNIT)	0.45	1185	0.71	$293.60
EMS - Replacing Lighting Controls (PER SQ FT)	0.00	2	0.62	$0.80
Street Lighting LED Watts > 100 & <= 200 (Per Fixture)	-	611	0.38	$341.77
Refrigeration/Miscellaneous | IT Equip | Computer Power Management - Laptop (PER COMPUTER)	0.03	125	0.98	$12.14
UPS (kVA)	0.03	217	0.92	$52.04
HVAC | Single Phase HP | <= 65 kBtu/h Class 4 | Eff Class 4 | S (Per kBtu/hr)	0.04	67	0.82	$43.73
Air Dryer Upgrades (SCFM)	0.00	13	0.80	$5.00
HVAC | Single Phase AC | <= 65 kBtu/h Class 5 | Eff Class 5 (Per kBtu/hr)	0.04	74	0.77	$51.58
Exterior Lighting | LED Channel Lights | LED Channel Lights (PER LINEAR FOOT)	0.01	26	0.63	$10.10
HVAC | Package Terminal HP | <= 7 kBtu/h (PER KBTU/H)	0.01	21	0.44	$19.66
Server Virtualization (Per Server)	0.23	1666	0.41	$475.22
Variable Speed HVAC (Ton)	0.41	679	0.29	$1,262.50
Hi-E Server (Per Server)	0.15	1114	0.25	$400.00
HVAC | Package Terminal AC | > 12 kBtu/h (PER KBTU/H)	0.02	59	0.22	$114.79
HVAC | Package Terminal AC | > 7 and <= 9 kBtu/h (PER KBTU/H)	0.01	25	0.16	$64.65
Motor | VSD | Other Blowers (PER HP)	-	-	-	$177.36

RULE D.16

Analysis of future fuel supplies that are part of the resource plan.

In 2019, Concentric Energy Advisors completed a study for APS that analyzed the supply outlook for natural gas and gas infrastructure, informing the preparation of the 2020 Integrated Resource Plan. As part of this study, coal generation outlook, gas and renewables generation, regulations and cost competitiveness were analyzed for the Southwestern US (including Mexico), and on a national level. Concentric's supply and demand outlook for the North American gas and energy infrastructure covered the technological, environmental, and economic factors driving the expectations for fuels and infrastructure of significant interest to APS: natural gas, gas pipelines, renewables, and impacts to coal generation. In addition to the report providing an outlook for North America (48 states and Mexico) as a whole, there is specific detail on gas delivery infrastructure from western production basins to Arizona, New Mexico and California.

Natural gas supply includes existing contract capacity, future extension of existing contracts, additional seasonal and annual contracts as well as short term contracts. All APS natural gas contracts are firm fixed delivery to assure adequate gas supply for peak seasonal demands. The natural gas supply and demand analysis was used to assess the APS gas use projection and gas infrastructure portfolio to ensure that current and future generation needs are fully met. This analysis was an input to APS resource planning effort. This assessment is designed to project peak seasonal natural gas use and identify the supply of gas for each of these seasonal peaks during the Planning Period. An example of this analysis can be found in Attachment D.16.

Based on these studies, APS reaffirms that the ongoing practice of procuring firm fixed gas fuel delivery contracts is appropriate and adequately addresses potential fuel supply and delivery during the Planning Period. See Rule E(f) for more information about future fuel supplies.

RULE D.17

A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

Plans to reduce environmental impacts related to air emissions and solid waste are provided in Figure D-1. Regulations impacting water and a plan for reducing impacts are included in Figure D-2.

FIGURE D-1. PLAN FOR REDUCING AIR AND SOLID WASTE ENVIRONMENTAL IMPACTS

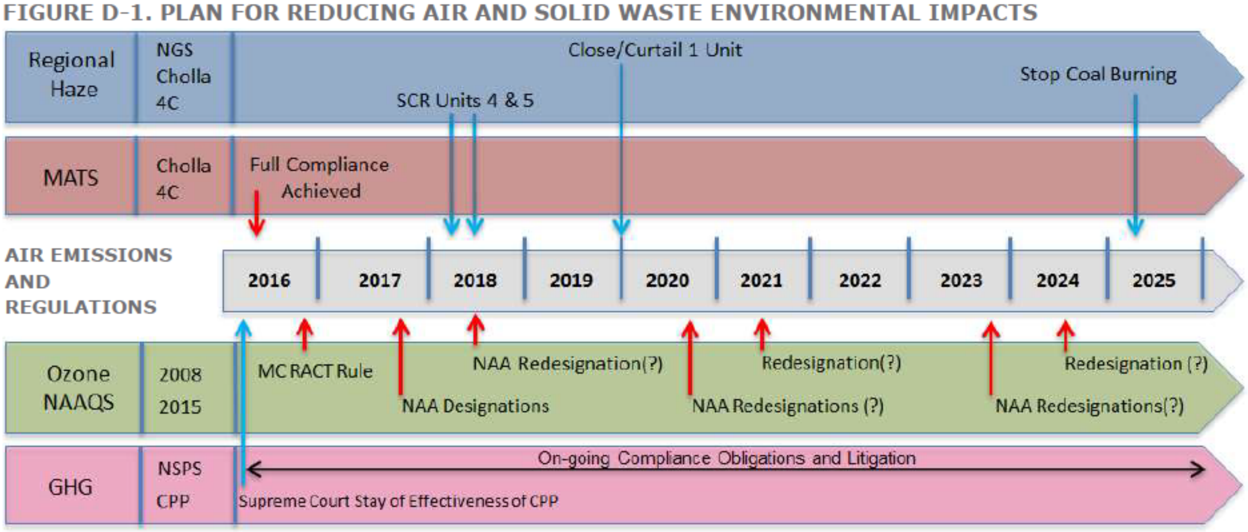
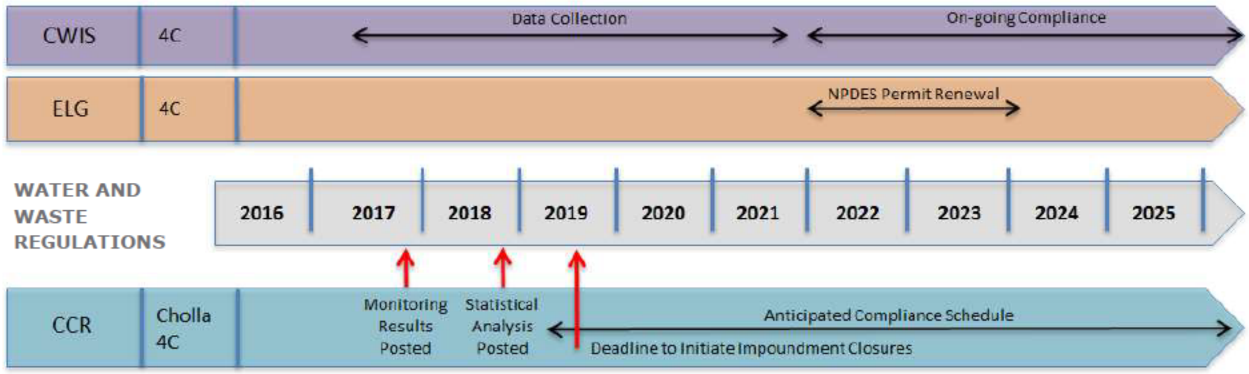


FIGURE D-2. REDUCTION OF ENVIRONMENTAL IMPACTS TO WATER



COMPANY RESPONSE TO CLIMATE CHANGE INITIATIVES

APS has undertaken a number of initiatives to address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency.

APS prepares an inventory of GHG emissions from its operations. This inventory is reported to EPA under the EPA GHG Reporting Program and is voluntarily communicated to the public in Pinnacle West's annual Corporate Responsibility Report, which is available on the Pinnacle West website (*pinnaclewest.com*). The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance.

EPA ENVIRONMENTAL REGULATIONS

REGIONAL HAZE RULES

In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal lands, EPA) to develop plans to achieve natural visibility conditions by 2064. The first planning period during which the regional haze rules were required to be implemented occurs between 2008 and 2018. The most impactful provisions of the rules were the requirement to determine what pollution control technologies constitute the Best Available Retrofit Technology (BART) for certain older major stationary sources. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis. The second planning period begins in 2018, but the plans that will demonstrate continued progress toward the goal of natural visibility conditions will not be submitted to EPA until July 31, 2021. It is possible that additional air pollution control technologies will be required to further reduce visibility impairing air pollution.

Cholla BART

On December 5, 2012, EPA issued a final BART rule applicable to Cholla. EPA partially approved and partially disapproved the State's BART determinations, and imposed its own sulfur dioxide (SO2) removal efficiency requirement and oxides of nitrogen (NOx) emissions limitations within a Federal Implementation Plan (FIP). In order to comply with the new limits, APS would have been required to upgrade the SO2 scrubbing efficiency and install selective catalytic reduction (SCR) technology on Units 2, 3 and 4. The state of Arizona, APS, and others sued EPA over this determination, along with other related-BART determinations. Concurrent to the litigation, APS offered an alternative BART Reassessment, which was premised on a commitment by APS shut down Unit 2 in 2016 and either shutdown the other units by April of 2025 or convert them to natural gas while operating at no more than a 20% capacity factor. In exchange for this commitment, Units 3 and 4 could continue operation without SCR.

On October 22, 2015, the state of Arizona submitted a State Implementation Plan Revision to EPA for approval that contained this alternative BART Reassessment. Public comment on EPA's proposed approval of the alternative BART Reassessment closed on September 1, 2016, and a final action was signed by former EPA Administrator Gina McCarthy on January 13, 2017. As soon as new EPA leadership selected by President Donald Trump has reviewed and approved this final rule, the Company expects the final rule containing the Cholla BART Reassessment will be published in the Federal Register and allowed to take effect. APS also anticipates additional review from the U.S. Office of Management and Budget may also be required before the rule takes effect. During this time, APS's litigation over the 2012 BART FIP as applied to Cholla remains in abeyance.

Four Corners BART

On August 6, 2012, EPA issued its final BART determination for Four Corners. On December 30, 2013, on behalf of itself and the Four Corners co-owners, APS notified EPA that the co-owners selected the BART alternative, which required APS to permanently shut down Four Corners Units 1-3, and install and operate SCR control technology on Units 4 and 5 by July 31, 2018. EPA also required a 95% SO2 removal rate, which requires some upgrades and restorations to the Flue Gas Desulfurization (FGD) systems. Consistent with this alternative, APS retired Units 1-3 on December 30, 2013, and permanent decommissioning of those facilities is complete. The addition of SCRs necessitated the addition of a Dry Sorbent Injection system to remove sulfuric acid mist created in the SCRs. Upgrades and restorations to the FGD systems and installation of the SCR control technology have been completed and are operational.

Navajo BART

EPA accepted SRP's proposal for an alternative to BART, which provides the Navajo Plant with additional time to install the SCR technology. Under this "better-than-BART" alternative, the Navajo Generating Station participants are required to shut down one unit or curtail the equivalent of one unit by January 1, 2020 and install SCR technology on the two remaining units by December 31, 2030.

MERCURY AND OTHER HAZARDOUS AIR POLLUTANTS

On December 16, 2011, EPA issued the final Mercury and Air Toxics Standard (MATS) rule, which established maximum achievable control technology (MACT) standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired power plants. APS has met all of its regulatory obligations for installing activated carbon injection on Units 1 and 3 at Cholla. Four Corners Units 4 and 5 were able to meet the mercury limit with existing equipment. Both facilities are fully compliant with the applicable emissions limitations.

COOLING WATER INTAKE STRUCTURES

EPA issued its final cooling water intake structures rule on August 15, 2014, which provides national standards applicable to certain cooling water intake structures at existing power plants and other facilities pursuant to Section 316(b) of the Clean Water Act. The rule is intended to protect fish and other aquatic organisms by minimizing impingement mortality (the capture of aquatic wildlife on intake structures or against screens) and entrainment mortality (the capture of fish or shellfish in water flow entering and passing through intake structures). The rule requires existing facilities such as Four Corners and Navajo Generating Station that use surface water to comply with the impingement mortality requirements as soon as possible, but in no event later than eight years after the effective date of the rule. Cholla is not impacted because its cooling water is supplied from well water. Existing facilities subject to the rule are required to comply with the entrainment requirements as soon as possible under a schedule of compliance established by the permitting authority. The Four Corners cooling water intake structure on the San Juan River was modified in 2017, connecting the two pump train sumps and reducing intake velocity to 0.5 fps, eliminating potential for impingement.

COAL COMBUSTION RESIDUALS (CCR)

On December 19, 2014, EPA issued its final regulations governing the handling and disposal of Coal Combustion Residuals (CCR), such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit the pond with a liner, or close. All CCR landfills or surface impoundments that cannot meet the applicable performance criteria for location restrictions or structural integrity are required to close. The provisions of this rule are self-implementing and currently rely upon citizens' lawsuits for enforcement of its requirements.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners, and also sells a portion of its fly ash for beneficial reuse as a constituent in concrete production. The known impacts of the rule are to initiate closure of two impoundments at Four Corners on or before June 17, 2019. In compliance with the requirements of the rule, APS is conducting on-going groundwater monitoring at both locations. All monitoring results are required to be made publicly available through a company-controlled website on or before October 17, 2017 and must update this information annually until 30 years after the closure of the ash ponds or dry storage areas. A statistical analysis of the collected data and an analysis of any required remedial actions must be completed and posted to the same website on or before October 17, 2018.

On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation (WIIN) Act into law. This act contains a number of provisions that require EPA to modify the self-implementing provisions of the Agency's current CCR rules. Specifically, EPA is provided with the authority to directly enforce the CCR rules through the use of administrative orders and, pending congressional appropriation, the obligation to develop a federal permitting program. EPA was also provided the authority to delegate permitting authority to the States through the approval of a state-proposed permitting program. Because EPA has yet to undertake implementation of the CCR provisions of the WIIN Act, and Arizona has yet to determine whether it will develop a state-specific permitting program, it is unclear what effects the CCR provisions of the WIIN Act will have on APS's management of CCR.

EFFLUENT LIMITATION GUIDELINES

On September 30, 2015, EPA finalized its revisions to the effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil fuel-fired Electric Generating Units (EGUs). The final regulation is intended to reduce metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and coal ash disposal leachate. Based upon an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, "zero-discharge" from fly ash and bottom ash handling, and impoundments for coal ash disposal leachate. Compliance with these limitations will be required as a part of the plant's National Pollution Discharge Elimination System (NPDES) permit which renews in five-year intervals. The NPDES program only impacts the Four Corners power plant. APS anticipates renewing the NPDES permit for the Four Corners plant between 2018 and 2023. Until a draft NPDES permit for Four Corners is proposed, APS is uncertain about what additional controls, if any, might be required to ensure that discharges from the facility are in compliance with the finalized effluent limitation guidelines.

OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS

On October 26, 2015, EPA adopted a new ozone NAAQS and set it at 70 parts per billion. This decision was legally challenged by various industry organizations yet supported by various states and environmental groups. The lawsuit is currently on-going. During this time, both the 2008 and the 2015 ozone NAAQS remain in effect.

In accordance with Clean Air Act requirements, on September 27, 2016, the state of Arizona made an initial recommendation that EPA classify the air quality in portions of Gila, Maricopa, and Pinal counties (e.g., Phoenix area) as a single non-attainment area, and a portion of Yuma County as a separate non-attainment area. The recommendation also suggested three other data-contingent alternatives for the

Phoenix area. EPA is required to make a final decision regarding the classification of air quality in Arizona by October 1, 2017.

In order to meet the Clean Air Act requirements for implementing the 2008 ozone standard, the Phoenix area was reclassified as moderate nonattainment, compelling the Maricopa County Air Quality Department to adopt new Reasonably Available Control Measures to reduce air pollution that leads to the formation of ozone. On November 2, 2016, County Rule 322 was revised to reduce emissions of nitrogen oxides and volatile organic compounds from fossil generation units. APS anticipates that it will need to install Dry Low NOx burners on West Phoenix CC 1 & 2 in order to comply with the provisions of this rule.

Given the Clean Air Act's requirements and the legal challenges to the 2015 ozone standard, APS will not know whether similar rules will be required for the Yucca Generating Station in Yuma County until 2020.

In addition to requiring existing sources of nitrogen oxides and volatile organic compounds to improve their air pollution controls, the process for obtaining new air quality permits in these areas is likely to become more stringent. New and modified major sources of these pollutants will be required to install the most stringent air pollution controls available and remove (offset) more air pollution than the facility is allowed to emit. Both requirements will increase the cost of potential future projects at APS facilities located within these non-attainment areas.

FOUR CORNERS CONSENT DECREE

In August 2009, APS responded to a request from EPA seeking detailed information regarding projects at and operations of Four Corners pursuant to Section 114 of the Clean Air Act. This request was part of an enforcement initiative that EPA had undertaken under the New Source Review (NSR) provisions of the Clean Air Act. APS denied and continues to deny the allegations brought by EPA and other environmental groups but did agree that settlement of the action was in the best interest of all of the Parties and the public interest. On August 17, 2015, APS entered into a Consent Decree that supplemented measures Four Corners had planned to implement for compliance with the 2012 BART determination. In addition to agreeing to the BART emission reduction requirements for nitrogen oxides and SO2, APS agreed to particulate matter emissions reductions requirements, the installation and certification of a particulate matter continuous emissions monitors, and three environmental mitigation projects within the Navajo Nation. The provisions of the Consent Decree do not terminate until at least December 31, 2021.

WATER SUPPLY

Water is used for power generation primarily to cool the steam-cycle by removing waste heat. It is also used for power augmentation, emissions control, auxiliary cooling, supporting chemical treatment processes, domestic purposes, and for other miscellaneous plant uses. APS manages water resources using a multi-layered approach to reduce water intensity. APS's plan for reducing water consumption includes the following actions:

- Employment of alternative cooling technologies for new generating resources;
- Improving the efficiency of water use during the Planning Period;
- New power plant construction, water saving alternatives;
- Retirement of existing power plant generating units, associated water savings;
- Reduce quantity of non-renewable groundwater consumed;
- Improve the efficiency of water utilization at APS's existing facilities; and
- Increase reliance on energy efficiency and renewable energy resources.

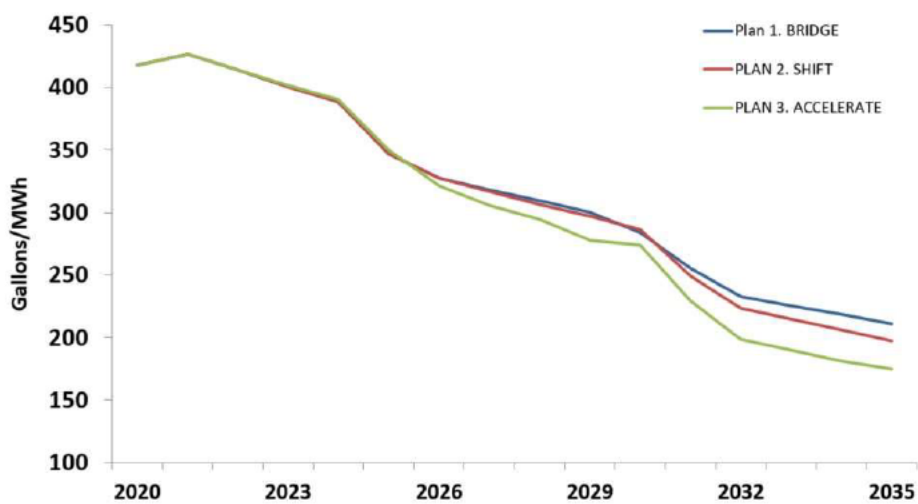
EMPLOYMENT OF ALTERNATIVE COOLING TECHNOLOGIES FOR NEW RESOURCES

For new facilities, APS evaluates alternative cooling technologies, water sources, and operating strategies in the best interests of the state, environment, and customers on a case-by-case basis; however, the use of alternative water supplies, such as effluent and alternative cooling technologies to reduce potable water usage comes with an additional cost in terms of capital investment and O&M costs, and may have an impact on unit efficiency. The factors influencing these decisions are diverse, including location, generator type, and renewable and alternative water availability. APS is developing a water supply portfolio that will provide a reliable mix of traditional, renewable, and reclaimed sources, minimizing where possible usage of groundwater and other potable water sources in favor of more sustainable resources. This approach is aimed at providing secure water supplies for power generation while fostering responsible water use. APS has a commitment to maximize use of renewable effluent and surface water and minimize use of non-renewable groundwater. Between 2019 and 2035, the Company's goal is to reduce our groundwater use by 71%-75%, depending on which Resource Planning strategy is adopted. More information on water use can be found in Chapter 1.

IMPROVING THE CONSUMPTION AND EFFICIENCY OF WATER USE DURING THE PLANNING PERIOD

Even though energy generation is forecast to significantly increase during the Planning Period to meet new customer demand, water consumption will decrease due to retiring older plants (replacing them with more water efficient plants), increasing energy efficiency, and increasing renewable energy resources envisioned in the three portfolios of the 2020 Resource Plan. This can be seen in Figure D-3, which shows the rate of water usage decreases 50%-58% between 2020 and 2035.

FIGURE D-3. Annual Water Rate (Intensity)



NEW POWER PLANT CONSTRUCTION, WATER SAVING ALTERNATIVES

When new power plant generating unit options are being evaluated, the water consumption rates for each technology option are considered and evaluated. The most significant water-saving device that can be installed on new power plants with steam turbines is air-cooled condensers in lieu of conventional wet-cooling towers. Technology for new dry-cooled combined cycle plants is estimated to use 20 gallons/MWh as compared to wet-cooled combined cycle plants such as Redhawk, which use approximately 307 gallons/MWh. APS, in conjunction with SRP and Tucson Electric Power Company, performed a detailed estimate of the equipment cost for an air-cooled condenser and determined the cost difference to be about $60 million, based on a nominal 600 MW combined cycle power plant constructed in the Arizona desert.

RETIREMENT OF EXISTING POWER PLANT GENERATING UNITS, ASSOCIATED WATER SAVINGS

- Retirement of Four Corners Units 1-3
  - In addition to evaluating alternative cooling technologies, further reductions in regional water consumption were achieved through the retirement of Four Corners Units 1-3, effective December 30, 2013. Retirement of these three units saves approximately 4,000-6,000 acre-feet of water annually. APS has announced retirement of the Four Corners plant in 2031.

- Retirement of Cholla Unit 2
  - Cholla Unit 2 was retired effective October 1, 2015, resulting in a decrease of approximately 3,000-4,000 acre-feet annually. Cholla remains the largest user of non-renewable groundwater in the APS fleet; however, APS has committed to cease coal generation at that site in 2025.

REDUCE QUANTITY OF NON-RENEWABLE GROUNDWATER CONSUMED

In 2016, APS developed and implemented a new Tier 1 metric designed to reduce consumption of non-renewable groundwater by 8%, compared to the reference year of 2014. Further reductions were planned in 2017 (10%), 2018 (12%), and in 2019 (14%). Actual 2019 results were 22.4% below 2014 consumption. This metric is achieved by retiring older water-intensive units and replacing them with more efficient units, by implementing water conservation measures at APS plants, and increasing reliance on RE and DE.

IMPROVING THE EFFICIENCY OF WATER USE AT EXISTING FACILITIES

APS manages water resources using a multi-layered approach to reduce water intensity. One approach has been to pursue projects targeted to improve the efficiency of water utilization at APS's existing plants. A primary example is Palo Verde Nuclear Generating Station, which not only uses reclaimed wastewater effluent as its cooling water source, but has focused on continual improvement in water treatment and operations to achieve over 23 cycles of concentration (on average) through the cooling water system. Redhawk also operates its cooling system using reclaimed water. In 2019, 71% of all water used by APS was reclaimed water, conserving fresh water for other purposes.

When considering water use and water efficiencies at power plants, APS considers not only the cost of projects, but also the potential impacts on society and the local environment. Understanding local and regional water use and trends is important to this decision-making. With that in mind, in 2009, APS formed its Water Resource Planning Department, consolidating many existing water-oriented functions and experience into a centralized, enterprise-wide function. The vision of this department is "to secure a sustainable and cost-effective supply of water to enable reliable energy production for APS customers." A primary initiative of the Water Resource Planning Department is to create a decision modeling center, consisting of a powerful database and computing infrastructure to allow modeling of groundwater supplies, surface water availability, and the characteristics of other water sources in conjunction with a variety of long-term energy production forecasts. By utilizing this quantitative approach in conjunction with geographic information systems, analysts and stakeholders can interactively assess the impacts of various decisions and scenarios.

APS has performed modeling of groundwater withdrawals and evaluated potential impacts of the withdrawals and has developed wellfield management plans at the largest water-consuming plants to enable more efficient use of the resource.

APS has also become more integrated into the Arizona water community enabling improved communication with other water stakeholders, including regulators, municipalities, agricultural users and other industries. APS is a representative on the Phoenix Active Management Area's (AMA)

Groundwater Users Advisory Council (GUAC). This council makes recommendations to ADWR's Phoenix AMA director on groundwater management and policy in the AMA. The Phoenix GUAC is the primary mechanism for public comment and review during ADWR's development of the Phoenix AMA's Fourth Management Plan. APS is a member of the ADWR 5th Management Plan Workgroup and the Post-2025 Active Management Area Committee. APS is a supporter of the Kyl Center for Water Policy, a research analysis and collaboration entity at the Morrison Institute for Public Policy at Arizona State University, promoting sound water policy and stewardship in Arizona. APS is a member of the Governor's Water Augmentation, Innovation, and Conservation Council, engaging in statewide, regional and international water planning. APS also provides a board member at the Water Resource Research Center at the University of Arizona, focused on improving water use and conservation in Arizona. This integration into the broader water community has opened communication and facilitated partnering opportunities for the future.

ENERGY EFFICIENCY, RENEWABLE ENERGY RESOURCES, AND AVOIDED WATER USAGE

Demand-side management programs and renewable energy resources generally consume little or no water. The expansion of these programs in the 2020 Resource Plan contributes to a reduction in water consumption over the Planning Period.

RESPONSE TO RULES

SECTION E
RISK

RESPONSE TO RULES SECTION E – RISK

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(E), which specifically requires information related to risk analysis and mitigation.

RULE E.1(A)

Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis: (a) demand forecasts.

The risks involved with developing a demand forecast involve uncertainties related to: (1) customer growth; (2) electricity usage; and, (3) weather. Table E-1 illustrates the results of a probabilistic approach.

TABLE E-1. PROBABILISTIC ANALYSIS OF PEAK DEMAND FORECAST

APS System Peak Demand Forecast (Probabilistic Analysis)								
PERCENTILE	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
10th	6,967	7,234	7,364	7,553	7,751	7,943	8,199	8,499
20th	7,110	7,399	7,534	7,740	7,946	8,159	8,449	8,728
30th	7,206	7,520	7,662	7,865	8,101	8,323	8,610	8,918
40th	7,304	7,626	7,767	7,971	8,225	8,446	8,740	9,090
Forecast	7,413	7,650	7,893	8,140	8,390	8,647	8,904	9,165
60th	7,479	7,812	7,959	8,187	8,465	8,695	8,995	9,372
70th	7,572	7,916	8,071	8,335	8,598	8,853	9,144	9,529
80th	7,686	8,036	8,203	8,471	8,734	9,001	9,358	9,692
90th	7,822	8,202	8,374	8,644	8,974	9,241	9,631	9,908

APS System Peak Demand Forecast (Probabilistic Analysis)								
PERCENTILE	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th	8,852	8,954	9,245	9,448	9,533	9,812	9,984	10,114
20th	9,057	9,235	9,478	9,731	9,834	10,092	10,305	10,487
30th	9,239	9,425	9,675	9,931	10,060	10,345	10,535	10,748
40th	9,387	9,636	9,861	10,081	10,239	10,544	10,765	10,984
Forecast	9,430	9,701	9,972	10,254	10,502	10,754	11,010	11,271
60th	9,686	9,958	10,218	10,410	10,638	10,931	11,188	11,403
70th	9,879	10,127	10,395	10,604	10,855	11,176	11,405	11,638
80th	10,077	10,303	10,666	10,848	11,105	11,439	11,695	11,956
90th	10,342	10,629	10,989	11,171	11,446	11,786	12,073	12,449

RULE E.2(A)

A description and analysis of available means for managing the errors, risks, and uncertainties identified and analyzed in subsection (E)(1), such as obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects: (a) demand forecasts.

A probabilistic analysis can be used to understand risk by providing a range of demand scenarios consistent with historical variations that APS has seen in customer growth, electricity consumption, and weather. Levels of demand can be illustrated by using percentiles ranging from 10% to 90%. The 10th percentile represents the likelihood of a lower demand outcome which would minimize the costs associated with procuring additional resources but contains a risk of not building a sufficient amount of resources if the actual demand exceeded the forecast. At the other end of the spectrum is the 90th percentile, a scenario with a higher demand outcome than is currently planned for and greater costs for procuring additional resources, which carries the risk of building too many resources than what might be needed if the actual demand was less than the forecast.

In the near term, weather presents the greatest risk to the forecast. Peak demand typically occurs during July or August when temperatures exceed 110°F. In the last ten years, the temperature on peak day has been as high as 119°F and as low as 113°F. Temperatures 2°F above the 10-year average of 115°F can add nearly 200 MW to peak.

Customer growth and changes in use per customer are the most important long-term risks to the demand forecast. Population growth, business investment and new technology development and deployment over the next 15 years could be quite different from the assumptions in the current forecast. The current forecast assumes a compound annual growth rate in residential customers of 1.7%.

Methods for managing these risks and uncertainties include utilizing resource options that have relatively shorter development lead times. Shorter development lead times allow utilities to respond quickly to changes in demand scenarios. Also, timely updates to the forecast with new information help ensure forecasts remain current. Lastly, having access to liquid wholesale power market trading hubs allows utilities to either buy or sell energy as needed to balance energy demands with resources.

RULE E.3(A)

A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (E)(1): (a) demand forecasts.

APS manages demand forecast risk in several ways. The Company has the ability to add short-lead-time resources, including battery storage and microgrids. The development time for these resource types can be anywhere from one to five years. Utilizing short-lead-time resources allows APS to respond quickly as demand scenarios change. APS also carries a 15% reserve margin of additional capacity, over the amount of demand actually forecast, to be available should customer demand exceed expectations or generating units do not perform as designed. Furthermore, APS benefits from transmission access to the Palo Verde wholesale trading hub. Because there are many wholesale market participants with access to Palo Verde, APS is able to buy and sell capacity and energy as needed to balance demand with resources.

RULE E.1(B)

Risk Identification: (b) the costs of demand management measures and power supply.

DEMAND MANAGEMENT MEASURES

Within the DSM market, the cost trajectory will vary depending on the program or measure, timing, and market saturation.

It is expected that as a whole, the cost per unit of energy saved through EE programs and measures will increase over time; the rate at which it increases will vary depending on technical developments, progression of building codes and appliance standards, persistence of behavioral changes after incentives disappear, and overall market penetration. That said, as future DSM programs are designed and proposed, cost-effectiveness must still be proven, which will likely change the landscape of future DSM measures as the current "low-hanging fruit" technologies are replaced by the next-generation, more efficient products and DSM programs.

In preparation for this Integrated Resource Plan, APS conducted an Energy Efficiency Market Opportunity Study to identify the technical, economic, and achievable energy efficiency savings potential, and the estimated range of costs to acquire these savings. The results of this study helped inform DSM modeling for this IRP and are also being used in ongoing DSM program planning efforts.

As with EE measures, the cost volatility of load management and demand response solutions continues to be an identified risk. Costs will be largely influenced by development of new communication standards, increased technical efficiencies, and environmental considerations.

Demand response programs typically include the need for real time communication of data during load management events. As these demand response programs scale, there are potential ongoing risks of communications failures and cybersecurity threats. To mitigate these risks, APS deploys a Resource Operating Platform that serves as a distributed energy resource aggregator to help manage and report on demand response activity by device. In addition to this platform, future investments will be needed to integrate the utility distribution management system with the resource operating platform, and to integrate each future type of distributed energy resource technology into the platform. In the near-term of the Planning Period, this may lead to an increase in IT costs, although the identified system efficiencies and customer services gained are expected to be positive investments from a financial, customer and technical perspective. These investments can provide an IT backbone to help improve reliability, decrease outage and response time, and provide tailored energy management solutions for customers.

Other customer load response resources, such as microgrids and energy storage, have demonstrated a downward trend in equipment and integration costs, although battery storage is still not currently a cost-effective DSM measure due to high upfront costs. The costs for new customer-sited generators such as microgrids have trended downward despite increased emission regulations and fuel costs. Ongoing industry cost reductions in DER and secure communication platforms that provide the real-time command and management of local loads and resources has made the application of utility-led microgrids increasingly possible and cost-effective for customers. Examples of suitable settings for microgrid projects include hospitals, military installations, data centers, universities, critical infrastructure, remote feeder locations and other customers with sensitive loads that cannot sustain loss of power. These customers traditionally procure their own back-up power systems to ensure continuous operation in the unlikely event of a power outage. APS partners with these customers to share in the cost and use of these resources, which have reliable and flexible operating characteristics to respond to their needs. By providing customers with needed backup power and APS with increased flexible capacity on its system, microgrids are beneficial to both participating and non-participating parties and may defer future capacity needs on the APS system, depending on cost and operational performance going forward.

POWER SUPPLY
Analyses to identify construction cost- and fuel cost-related risks and uncertainties are addressed in subsequent sections.

Other risks associated with costs of power supply involve surplus or shortfalls in meeting reserve requirements. APS manages three types of reserves at three different time intervals: planning reserves – these are the reserve requirements calculated at annual timescales and encapsulated in Attachment F.9(b) line 4; contingency reserves – these are made up of spin- and non-spin reserves and are managed on an hourly basis, and; frequency response reserves – these are managed at a sub-minute level and help to maintain frequency on the regional transmission system after contingencies. Surplus and shortfalls in any of these categories can bring about financial risk in terms of surplus variable or capacity costs, if reserves are in surplus, or risk of overpaying during states of emergency or from paying fines for failing to meet requirements, if reserves are too low. Surpluses and shortfalls are also affected by regional availability of capacity resources.

Though APS has always had cost risk related to surplus or shortfalls in reserve requirements, solar penetration has increased the magnitude of risk related to contingency and frequency reserve requirements and distributed generation has added an element of uncertainty when developing planning reserves. Descriptions of these three risks follow:

Frequency Reserves: Cost risk can occur when frequency reserves are in surplus (but reliability is higher) or below minimum requirement levels. APS strives to balance reserve costs and reliability. Operations disruptions from unplanned generation or transmission line outages – have historically posed the greatest challenges. However, more recently, intermittency related to solar generation adds an additional level of cost risk as generation output can vary at short time intervals due to cloud movement.

Contingency Reserves: Likewise, power supply cost risk may result from forecast error. APS utilizes various forecasting tools to minimize risks to over- or under-generation. These forecasts include demand, weather and load- and utility-side renewable production. The potential magnitude of load- and utility-side renewable production forecast error is expected to increase with additions of wind and/or solar to the APS system.

Planning Reserves: APS targets a 15% planning reserve margin in order to have the available capacity to cover needed frequency and contingency reserves for its balancing area.

RULE E.2(B)

Risk Analysis: (b) the costs of demand management measures and power supply.

DEMAND MANAGEMENT MEASURES
Annually, on-going analyses will be performed as part of each DSM Implementation Plan filing to ensure that proposed and existing DSM programs are cost-effective and advantageous for APS and its customers. The results of the most current analyses are provided in Rule D.14.

POWER SUPPLY
Specific methods to manage construction cost and fuel cost-related risks and uncertainties of the costs of power supply are addressed in subsequent sections.

Real-time operations power supply cost risks have traditionally been managed through NERC reliability requirements. Many compliance costs associated with these NERC requirements have been managed through APS's participation in regional reserve sharing groups, such as the Southwest Reserve Sharing Group. Continued increases in the amount of intermittent generation, such as wind and solar, on the electric grid are expected to increase frequency and contingency reserve-related costs. APS employed Energy Exemplar to analyze solar and wind integration costs in order to quantify cost impacts related to carrying additional operations reserves. These analyses are discussed in more detail in response to Rule D.11. As a general rule, integration costs increase with increased levels of solar and/or wind penetration. Integration costs increase because the magnitude of potential power supply disruptions increase with more MW of solar and/or wind.

Power supply cost impacts related to forecast error is often situation dependent and are expected to increase with increasing additions of solar and wind generation. APS analyzes weather, load and renewable forecasts on a daily basis and analyzes patterns so that forecasts can be improved. Over the past several years, APS has vastly improved their renewable forecasting capabilities. These improvements can be attributed to:

- Localized (at the generation site) weather forecasts in partnership with the University of Arizona, leaders in Desert Southwest regional weather and climate forecasting;
- Cloud cover and irradiance forecasting improvements due to the addition of several algorithms to better anticipate cloud cover movement;
- Fine tuning of APS internal systems to significantly reduce latency; and
- Latency improvements to CAISO market systems that APS interacts with.

Planning reserve cost impacts depend upon the magnitude and direction of the difference in annual forecasted distributed energy additions and actual.

RULE E.3(B)

Risk Mitigation Plan: (b) the costs of demand management measures and power supply.

DEMAND MANAGEMENT MEASURES

Embedded within Arizona's EE/DSM Rules is a cost-effectiveness requirement which acts as a mechanism to ensure that all DSM programs that are implemented provide a net benefit to APS and its customers. APS uses cost tests to rank DSM programs in order of effectiveness in reducing peak, however these tests alone are not enough. In addition, APS has worked to develop hourly load shapes for each DSM program and measure that show the energy impacts of the program broken down by each hour of the year. These program impact load shapes are used to optimize the DSM portfolio to best align with APS resource needs and to better inform the load forecast of future DSM savings.

Annually, APS seeks to manage EE program costs by exploring innovative incentive models, creating additional technology options, deploying new marketing and outreach strategies, and conducting Measurement and Evaluation Research (MER) on the programs to identify opportunities for improvements.

Due to the varied nature of load management and demand response solutions, cost volatility can be more closely managed by strategically timing deployment of resources and diversifying procurement methods. The APS Peak Solutions program is managed through a long-term contract (through 2024) that has fixed energy and capacity payments through the term of the agreement. APS is currently conducting an RFP process for Peak Solutions program capacity from 2021-2025, which could result in changes to this existing contract as well as potential for additional capacity to be added to the program. This process provides APS with an opportunity to explore current market pricing and further manage future costs.

Additionally, time-differentiated rate schedules and tariffs are eligible to be re-filed as necessary to assist in managing customer and Company impact. APS will have the opportunity to revisit these rates in the annual DSM Implementation Plan filings or through rate cases.

POWER SUPPLY

APS optimizes the use of its resources to serve its customers in the most affordable manner possible, while maintaining grid reliability. The process begins by forecasting the load on a day-ahead basis. The load forecast is entered into a unit commitment and dispatch model (PCI GenTrader®/GenPortal®) that determines the most economic unit commitment plan for serving load, taking into account generating unit capabilities, intermittent resource production forecasts (e.g., wind and solar), fuel prices, contractual requirements, and transmission constraints. This commitment plan shows the units to be committed each hour, their projected loading level and the quantity of natural gas to be scheduled.

As part of the process, the model calculates prices for blocks of energy to help determine if it would be cheaper to buy power from the market rather than to run generating units. The day-ahead trader compares these calculated block energy prices with actual power prices being offered in the market, then purchases either on-peak or off-peak blocks of energy, if economical. The model also calculates the breakeven price for making sales out of the Company's generating resources, after taking into account native load and any other pre-existing power sales commitments. Based on expected system conditions, the day-ahead trader will make power sales in the market.

The day-ahead commitment plan is turned over to the real-time operations team to take forward into the intraday markets. The real-time traders update the load and available resource forecasts and re-run the unit commitment and dispatch model to fine-tune the commitment plan. They also check the intraday market to make purchases and sales of power to further optimize the system.

Within the sub-hourly window, the real-time traders proceed to further refine the Company's generation plan by interacting with the CAISO Energy Imbalance Market (EIM) to transfer energy when economically beneficial to customers. Through calculated cost curves of each unit, the real-time traders determine which generators may be incremented, decremented, committed (start) and de-committed (shutdown) as part of a greater EIM footprint solution. While considering available transmission resources, fuel supplies, and reliability needs, APS participates in both the 5-minute and 15-minute markets while maintaining the NERC required reserves and system stability requirements. Each of these markets use dynamic meter and load data as well as 5-minute renewable forecasting to dispatch all participating units with the goal of reducing the production cost for APS customers and the greater EIM footprint.

As the final step in this process, the real-time traders issue the commitment instructions to generating units as needed to meet load and sales commitments. Additionally, they respond to dynamic changes by updating the plan as needed for generating unit or transmission outages and forecast updates; continuously optimizing usage of available resources.

For the duration of the Planning Period, the generating unit commitment procedures are not expected to change from one year to the next.

RULE E.1(C)

Risk Identification: (c) the availability of sources of power.

Risks involved in the availability of sources of power include the availability of the supply resource itself, availability of new generation equipment, timing of construction schedules, availability of credit-worthy counterparties, the commercial viability of certain technologies, and the availability of adequate transmission capacity to move the power to the load center where it is needed.

RULE E.2(C)

Risk Analysis: (c) the availability of sources of power.

One of the key risks that APS addresses on a daily basis is the potential of reduced generating availability and outages in the fleet of existing supply resources. This risk of an equipment or plant malfunction and unplanned shutdown is present on a continuous basis but is generally minimized through high standards in plant maintenance and operations. In addition, APS plant designs incorporate a reasonable level of redundancy at the equipment level so that single failures do not generally result in plant outages.

Providing for an allowance in the timing of construction schedules for planned generation is one way the construction schedule risk can be mitigated. When planning for summer peak resource requirements, an allowance can be made for the level of capacity a particular resource is allowed to contribute toward meeting that summer peak demand. For projects that are anticipated to reach commercial operation during the summer period of June-September, a risk-reducing strategy may be to not rely upon those projects' capacity for meeting that particular summer peak. In this way, construction schedule risk is mitigated.

Having additional resources available is another means of managing risk in the availability of sources of power. Utilities carry capacity reserve margins (surplus reserve capacity) in the event of resources being unavailable or customer demand being higher than anticipated. Capacity reserve margins are an effective means to help ensure sufficient power sources are available when needed.

Following robust procurement practices is another way to mitigate risk of availability of sources of power. Soliciting bids from a large number of third-party developers allows the Company to select projects that are more likely to be completed on time. Developers often may already own property, have permits in place, and have good queue positions for equipment.

When procuring energy from third-party vendors, an analysis of vendor credit quality is crucial to the success of a transaction. Poor credit quality or the inability of a vendor to obtain cost-effective and timely financing for their project will, in most circumstances, exclude that vendor from being considered. A thorough analysis of vendor credit quality helps to mitigate these impacts.

Consideration of a wide range of technologies increases resource diversity and reduces technology performance risk. Being overly dependent on a single technology or depending on technologies that have yet to be proven in commercial applications may increase performance risk.

One of the single best, and simplest, means of managing risk in sources of power is resource diversity (i.e., not being overly reliant on one fuel source). Utilities with diverse sources of power supply are situated better when unforeseen problems emerge because they have other alternative sources of power to rely upon.

To optimize the economic alternatives of running generating units versus procuring energy from the market, having transmission access to liquid trading hubs is another means of helping to ensure availability of sources of power.

RULE E.3(C)

Risk Mitigation Plan: (c) the availability of sources of power.

Existing plant availability is maintained at very high levels through the application of effective preventative and predictive equipment maintenance. APS maintains an operational staff which is capable and highly trained. Programs are in place which promote the capture of data and evaluation of equipment failures and operational incidents to help prevent recurrence and reduce the risk of unexpected outages.

APS mitigates risk due to the timing of construction schedules by not including those projects' capacity as contributing toward meeting summer peak demand when their initial commercial operation date is anticipated to be during the summer (June – September). By mitigating construction schedule risk in this manner, system reliability is not compromised if projects are delayed.

As described in response to Rules E.1(a) – E.3(a), APS plans to carry a minimum 15% planning capacity reserve requirement that helps ensure sufficient power sources are available. APS's capacity reserve requirement for 2020 is 1,026 MW, as shown on line 3 of Attachment F.9(b).

The Company also mitigates risk by engaging in best practice procurement procedures. Whether APS signs a purchase power agreement, purchases an existing asset, or constructs new generation, the best projects are identified through well participated, open solicitations.

APS employs credit risk management practices that ensure the creditworthiness of all counterparties in energy procurement transactions has been thoroughly analyzed prior to making a transaction. In addition to determining the credit quality of potential counterparties, APS also may require a letter of credit, guarantee, or some other form of acceptable collateral prior to completing a transaction. In this manner, if a counterparty were to default on their contractual obligations, APS could retain the collateral of the defaulting counterparty to help offset any damages APS may have incurred as a result of the counterparty default.

APS employs a wide range of resources and is not overly dependent on any one specific resource, as illustrated by the diversity of the supply-side resources included in each of the three portfolios presented in the 2020 IRP. APS limits risk exposure by considering only sources of power reasonably believed to be commercially available within the planning time frame.

APS has taken steps to promote a contingency planning process that is designed to identify uncertainties in the existing portfolios and develop options for new resources and transmission capacity, which can be implemented in the identified timeframes. These options are intended to be executable compensatory measures in the event of failure of specific elements of the current resource plans.

In terms of renewable energy, the three portfolios presented in the 2020 IRP include solar photovoltaic, solar plus energy storage, wind and biomass. By considering commercially available resources such as those mentioned, APS mitigates technology performance risk.

With the revised battery project timelines, APS may use existing generation in the region as a bridging strategy to meet the projected load plus reserve margin. These short-term purchases ensure that we can meet summer reliability requirements and will be structured not to impact longer-term resource planning strategies. Currently, we expect short-term needs will be met with wholesale market purchases from a combination of existing merchant natural gas units, neighboring utilities, wholesale market participants and demand response. When APS chooses to construct new capacity, it is anticipated that there will be many manufacturers and many technology options to choose from, along with sufficient availability of new equipment.

Through its ownership interest in PVNGS, APS benefits from transmission access to the wholesale power market at the Palo Verde hub. Many market participants, as well as merchant generators, buy and sell wholesale power at the Palo Verde hub making access to that facility one of the means APS uses to manage the risk of power source availability.

RULE E.1(D)

Risk Identification: (d) the costs of compliance with existing and expected environmental regulations.

EPA is currently in various stages of promulgating environmental regulations, which are expected to impact APS. Factors that will impact future costs of compliance include:

- Capital and O&M costs pertaining to existing regulations are subject to cost increases triggered by inflation or limited supply;
- Existing regulations may change during the Planning Period;
- The requirements to comply with many of the proposed regulations have not been finalized, so it is difficult to estimate precise costs of unknown regulations; and
- New technology may be required to achieve compliance with proposed regulations, and the cost of the new technology may be unknown.

APS monitors the regulatory landscape as potential environmental regulations evolve and become better defined. Throughout this process, APS environmental engineers develop refined cost analyses using scenarios containing a range of potential technology requirements to forecast the cost of possible outcomes.

ANALYSIS OF UNCERTAINTY PERTAINING TO REGIONAL HAZE REGULATIONS (BART)

In 1999, EPA published a new rule regarding regional haze, which includes decreasing NO_x, SO_2, and PM emissions at various major stationary sources of air pollution, including the Four Corners and Cholla Power Plants. Low NO_x Burners and Over-Fired Air were installed at these plants during the 2007 to 2009 timeframe. Thereafter, EPA proposed Best Available Retrofit Technology ("BART") pollution control requirements for the Four Corners and Cholla Power Plants that would have required Selective Catalytic Reduction ("SCR") controls to achieve compliance with the contemplated NOx limits.

As an alternative to the SCRs at Cholla, APS offered to shut down Unit 2 by October 2015 and either shut-down or convert the other units to natural gas by April 1, 2025 if EPA agrees to Low NO_x Burners and Over-Fired Air. EPA has accepted this alternative and finalized the revised state implementation plan (SIP) containing requirements to this effect in 2017. Given the finalizations of the SIP, and APS's plan to cease coal burning at Cholla by April of 2025, there is no risk that BART-driven SCRs would be required at Cholla.

On December 30, 2013, APS, on behalf of itself and the other co-owners, notified EPA that they had selected an alternative BART compliance strategy for the Four Corners facility, which required the closure of Units 1-3 by January 1, 2014 and installation of SCR controls on Units 4 and 5 by July 31, 2018. The risk for additional costs from BART at Four Corners lies mainly in the cost estimate for reagent usage. Increased reagent usage could increase O&M by $5.4M per year to $6.5M per year. Also, there is a potential of high volatility in the urea market. APS works with a long-term supply contractor for urea, and that contract(s) is periodically reviewed and renewed, but the volatility in the urea market impacts cost, no matter the supplier.

During the next (i.e., second) planning period, which will run from 2019 through 2028, the state of Arizona must consider man-made sources of visibility-impairing pollutants for potential Reasonable Progress controls. Reasonable progress controls will be assessed through a four-factor analysis that considers the following:

- The cost of control,
- The time necessary to install controls,
- Energy and non-air quality impacts, and
- Remaining useful life.

All sources of air pollution could potentially be subject to additional emission control requirements in the second and subsequent planning periods of the Regional Haze program. State plans that will demonstrate continued progress toward the goal of natural visibility conditions will not be submitted until July 31, 2021. The Arizona Department of Environmental Quality has hosted several stakeholder meetings regarding its regional haze plan development and APS has engaged with ADEQ to better understand how the process could impact its facilities. At this time, APS cannot predict the final results of this process.

ANALYSIS OF UNCERTAINTY PERTAINING TO MERCURY AND AIR TOXICS STANDARDS (MATS) REGULATIONS

In 2012, EPA finalized new regulations to control mercury and other hazardous air pollutants (HAPS). Coal units are most affected by this rule. Activated Carbon Injection was installed on Units 1 and 3 at Cholla in 2014, and the plant has maintained continuous compliance with the MATS regulation since that time.

It appears that reagent will not be required at Four Corners to control mercury emissions. APS has completed the process of upgrading flue gas desulfurization (FGD) systems to improve mercury and SO_2 control. Mercury excursions at start-up could prompt the addition of a re-emission chemical for the plant FGD system. To date, however, Four Corners has not experienced start-up re-emissions since installation and continuous operation of the SCR system. If it turns out that a re-emission chemical is required, APS's share of total capital costs to comply with the MATS rule at Units 4 and 5 could increase by $1.2M and re-emission chemical usage could be $1.7M per year.

ANALYSIS OF RESOURCE CONSERVATION RECOVERY ACT (RCRA) SUBTITLE D

On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below.

Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants:

Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to, either, authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits.

- On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019 to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal.

- Based on an August 21, 2018 D.C. Circuit decision, which vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, EPA recently proposed corresponding changes to federal CCR regulations. On November 4, 2019, EPA proposed that all unlined CCR surface impoundments, regardless of their impact (or lack thereof) upon surrounding groundwater, must cease operation and initiate closure by August 31, 2020 (with an optional three-month extension as needed for the completion of alternative disposal capacity).

- On November 4, 2019, EPA also proposed to change the manner by which facilities that have committed to cease burning coal in the near-term may qualify for alternative closure. Such qualification would allow CCR disposal units at these plants to continue operating, even though they would otherwise be subject to forced closure under the federal CCR regulations. EPA's proposal regarding alternative closure would require express EPA authorization for such facilities to continue operating their CCR disposal units under alternative closure.

APS cannot at this time predict the outcome of these regulatory proceedings or when EPA will take final action. Depending on the eventual outcome, the costs associated with APS's management of CCR could materially increase, which could affect APS's financial position, results of operations, or cash flows. APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $22 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $15 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APS's share of incremental costs is approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring.

As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must cease operating and initiate closure by October 31, 2020. APS initiated an assessment of corrective measures on January 14, 2019 and expects such assessment will continue through mid- to late-2020. As part of this assessment, APS continues to gather additional groundwater data and perform remedial evaluations as to the CCR disposal units at Cholla and Four Corners undergoing corrective action. In addition, APS will solicit input from the public, host public hearings, and select remedies as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rule's corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until the Company has fully completed the corrective action assessment process, any ultimate impacts to the Company cannot be predicted; however, at this time the Company does not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on its financial position, results of operations or cash flows.

ANALYSIS OF UNCERTAINTY PERTAINING TO NATIONAL AMBIENT AIR QUALITY STANDARD (NAAQS) REGULATIONS

The NAAQS for Ozone are the most significant driver of regulatory risk as it concerns NOx emissions control from gas-fired APS facilities located within Maricopa County, these include the 2008 Ozone NAAQS set at 75ppb and the 2015 Ozone NAAQS set at 70ppb. Pursuant to the existing 2008 Ozone NAAQS, the CC1 and CC2 units at West Phoenix Power Plant will likely require additional NOx controls within the next few years, depending on on-going permitting proceedings as between Maricopa County and EPA Region IX. APS cannot at this time predict the precise level of control that will be necessary.

As for the 2015 Ozone NAAQS, on April 30, 2018, EPA designated the geographic areas containing Yuma and Phoenix, Arizona as in non-attainment with the 2015 70ppb Ozone NAAQS. With ozone standards becoming more stringent, APS's fossil generation units will come under increasing pressure to reduce emissions of NOx and volatile organic compounds, and to generate emission offsets for new and modified sources of air pollution, including new and modified generating sources, within in the ozone nonattainment areas. APS anticipates that revisions to the SIPs and FIPs implementing required controls to achieve the new 70 ppb standard will be in place between 2023 and 2024. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

ANALYSIS OF UNCERTAINTY PERTAINING TO NEW SOURCE REVIEW (NSR) REGULATIONS

Under the NSR rules, a project at an existing unit triggers pre-construction permitting and additional control requirements if it is a physical or operational change that would result in a significant net emission increase. Projects considered to be "routine maintenance, repair, and replacement" are categorically excluded. On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners co-owners alleging NSR violations. In conjunction with the Regional Haze BART proceedings, APS has reached an agreement with EPA to put SCR controls on Units 4 and 5, while upgrading and enhancing certain other pollution controls at the plant, and resolve all allegations of NSR violations at Four Corners associated with Units 4 and 5. This agreement was finalized in August of 2015. There is still the possibility of new alleged NSR violations at Four Corners or Cholla, and the Company cannot at this time predict the outcome of any proceedings necessary to resolve such allegations.

ANALYSIS OF UNCERTAINTY RELATED TO THE AFFORABLE CLEAN ENERGY RULE

In June 2019, the EPA issued the Affordable Clean Energy rule (ACE) as a replacement for the Clean Power Plan. This rule focuses on reduction of greenhouse gas emissions through Heat Rate Improvements at individual coal-fired units. Given that Four Corners is located on the Navajo Nation, APS has made the case that it is neither necessary nor appropriate to apply this Rule to the Four Corners facility. As such, it remains to be seen whether or not ACE requirements will impact plant operations at Four Corners. Additionally, given the near-term date of operations cessation of all remaining units at the Cholla plant (by April of 2025), the APS team is currently coordinating with AZDEQ about how to best move forward with an appropriate path forward for Cholla. Given the imminent closure date of the plant and the fact that most of the designated HRIs have already been installed at Cholla to some degree, the expected impact to the site from this Rule is minimal.

ANALYSIS OF UNCERTAINTY RELATED TO EFFLUENT LIMITATION GUIDELINES (ELG)

The Clean Water Act (CWA) regulates discharges to "waters of the U.S." through water quality standards and technology-based standards. Effluent Limitation Guidelines (ELG) are technology-based standards developed by EPA on an industry-by-industry basis. The CWA requires EPA to review periodically and revise these standards as appropriate. On November 3, 2015, EPA finalized revised ELG wastewater discharge limitations for fossil-fired electric generating units. The revised power plant ELGs target metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities and non-chemical metal cleaning wastes operations.

The revised ELG standards will likely only impact the Four Corners facility, which discharges wastewater, including bottom-ash transport water, into a surface water body subject to CWA jurisdiction. Pursuant to an NPDES permit reissued for this facility on September 30, 2019, Four Corners must comply with the revised ELGs for bottom-ash transport water and cease all such discharges by December 31, 2023. This permit is currently subject to an appeal by various environmental groups before the EPA Environmental Appeals Board. In addition, EPA recently proposed a further revision to the power plant ELG standards that would, if finalized as proposed, relax somewhat the current zero-liquid discharge requirements for this plant. APS cannot at this time predict the outcome of these proceedings. APS's share of the ELG compliance costs at Four Corners is currently estimated to be approximately $6-20M for capital and $0-2.7M per year for O&M.

RULE E.2(D)

Risk Analysis: (d) the costs of compliance with existing and expected environmental regulations.

Available means for managing errors, risks, and uncertainties include the following strategies:

- Obtain current information from sources, such as federal and state agencies, industry publications, vendor presentations, discussions with other utilities, market research, and third-party consulting organizations, to maintain awareness of proposed changes to existing and expected regulations, which will impact technology choices and cost;
- Serve on environmental control technology committees within industry organizations;
- Analyze commercially-viable options for technologies that will enable environmental compliance;
- Negotiate solutions with government agencies that balance cost and compliance;
- Update costs of technology needed for compliance throughout the development of the regulation and as expected regulations become finalized, including increases in cost due to inflation or limited supply; and
- Pursue an expanded portfolio of non-emitting resources that includes energy efficiency, demand response, and renewable energy to defer the cost of additional environmental control technology by delaying new conventional fossil generation. A key component is flexibility which is supported by APS's participation in the California ISO EIM and with the Ocotillo Modernization Project.

RULE E.3(D)

Risk Mitigation Plan: (d) the costs of compliance with existing and expected environmental regulations.

To manage risks and uncertainties with the cost of existing and expected environmental regulations, APS uses a multi-faceted plan, which includes a combination of the following:

- **Obtain information from sources such as federal and state agencies and third-party consulting firms to maintain awareness of proposed changes and to evaluate commercially-viable options for technology:**

For example, APS used Black & Veatch, a global engineering consulting firm, to provide the initial evaluation and subsequent updates for commercially-viable technology required for SCR controls installation at the Four Corners Power Plant, as well as to provide cost estimates. As a risk mitigation strategy, APS also conducts market research to mitigate uncertainties when evaluating new and changing technologies to ensure that the most reasonable technologies are selected to balance cost while meeting environmental standards.

- **Serve on environmental control technology committees:**

The Electric Power Research Institute (EPRI) is an organization in which APS participates as a member of committees involved with environmental control technologies. Membership in this organization also provides contacts at other utilities who can share their experiences with us.

- **Negotiate solutions with government agencies that balance cost and compliance:**

APS worked with the EPA to develop a solution for controlling NO_x and SO_2 emissions at the Cholla and Four Corners Power Plant, which balanced environmental impacts with the cost of compliance (see response to Rule D.17). As additional environmental regulations are developed and proposed, APS expects to continue working with its regulatory partners on effective environmental protection solutions that maximize compliance cost reductions.

- **Review and update cost estimates based on the latest information available:**

Throughout the process of developing environmental regulations, more rigorous cost estimates are continually produced by APS to reduce cost uncertainty.

- **Defer the cost of additional environmental control technology by pursuing a diverse portfolio of resources that includes energy efficiency, demand response, and renewable energy:**

As illustrated in the three portfolios presented in the 2020 IRP, APS is managing the risk of environmental regulations by ramping up non-emitting resources, such as energy efficiency, demand response, and renewable generation. This strategy defers the cost of additional environmental control technology by delaying the need to add conventional fossil generation.

- **Analyze portfolio cost risks related to existing and expected environmental regulations:**

APS includes a varied group of resource portfolios in order to measure cost impacts of various levels of compliance with MATS, BART and potential CO_2 legislation. Results from these analyses will help APS evaluate future emission control investment strategies.

RULE E.1(E)

Risk Identification: (e) any analysis by the load-serving entity to identify and assess errors, risks, and uncertainties in anticipation of potential new or enhanced environmental regulations.

An analysis of several potential new environmental regulations, which would require capital and O&M expenditures for environmental control equipment was discussed in detail in the response to Rules D.17 and E(d). In addition, an implementation plan was included in response D.17 which identified the potential technology and time frame for design and installation based on the most current information available as of January 2020. As previously discussed, most of these potential regulations are only partially defined at this time, and some may not be finalized for years. Over the 15-year Planning Period, these regulations could be modified further resulting in changes to the technology needed for compliance, which would impact the forecast for compliance costs.

In addition to proposed regulations of which APS is currently aware, there are potential new regulations, such as another round of regional haze rules (a new EPA long-term strategy planning period started in 2019 and Arizona is currently developing its plans) and revised or new GHG regulations, which could be promulgated during the Planning Period, depending upon the results of the 2020 presidential election. Compliance costs could increase to an extent that is unknown at this time.

ANALYSIS OF UNCERTAINTY RELATED TO CO2 CAPTURE AND SEQUESTRATION (CCS) REGULATIONS

On August 3, 2015, EPA finalized a New Source Performance Standard (NSPS), under the Clean Power Plan, to limit emissions of carbon dioxide (CO_2) for new coal plants and natural gas combustion turbines. The rules for new coal-fired units would require the installation and operation of Carbon Capture and Sequestration (CCS) technology and are cost prohibitive. The rules for new natural gas units are based on high efficiency combined cycle units. Low capacity factor combustion turbines, including simple cycle units, are exempt.

On June 19, 2019, EPA took final action on its proposals to repeal EPA's 2015 CPP and replace those regulations with a new rule, the Affordable Clean Energy (ACE) regulations. The ACE regulations are based upon measures that can be implemented to improve the heat rate of steam-electric power plants, specifically coal-fired EGUs. In contrast with the CPP, EPA's ACE regulations would not involve utility-level generation dispatch shifting away from coal-fired generation and toward renewable energy resources and natural gas-fired combined cycle power plants. EPA's ACE regulations provide three years to develop plans establishing source specific standards of performance based upon application of the ACE rule's heat-rate improvement emission guidelines. While corresponding New Source Review ("NSR") reform regulations were proposed as part of EPA's initial ACE proposal, the finalized ACE regulations did not include such reform measures. EPA announced that it will be taking final action on EPA's NSR reform proposal for EGUs in the near future.

APS cannot at this time predict the outcome of EPA's regulatory actions repealing and replacing the CPP. Various state governments, industry organizations, and environmental and public-health public interest groups have filed lawsuits in the D.C. Circuit challenging the legality of EPA's action, both, in repealing the CPP and issuing the ACE regulations. In addition, to the extent that the ACE regulations go into effect as finalized, it is not yet clear how the state of Arizona or EPA will implement these regulations as applied to APS's coal-fired EGUs. In light of these uncertainties, APS is still evaluating the impact of the ACE regulations on its coal-fired generation fleet.

RULE E.2(E)

Risk Analysis: (e) any analysis by the load-serving entity to identify and assess errors, risks, and uncertainties in anticipation of potential new or enhanced environmental regulations.

Available means for managing the risks and uncertainties with the analysis of new environmental regulations includes the following strategies:

- Obtain information from sources, including federal and state agencies, industry publications, market research, and third-party consulting organizations, to maintain awareness of proposed changes to existing and expected regulations that will impact technology choices and cost;
- Evaluate commercially viable options for technologies that will enable environmental compliance;
- Serve on environmental control committees within industry organizations;
- Negotiate solutions with government agencies that balance cost and environmental impact;
- Update costs of technology needed for compliance as better information becomes available;
- Monitor executive, legislative and judicial activities related to CO_2 and develop cost sensitivities to evaluate the potential impact;
- Develop additional options, including scenarios containing minimum and maximum technology requirements to evaluate the range of possible outcomes;
- Incorporate a hypothetical carbon cost into resource planning analytics;

- Implement the formal regulatory review process to ensure review of, identification of impacts from, and when necessary, provision of comment on, all new and revised environmental regulations;
- Implement the existing Environmental Management Information System to ensure all required activities are completed and recorded; and
- Continued implementation of the ISO 14001 Certified Environmental Management System.

RULE E.3(E)

Risk Mitigation Plan: (e) any analysis by the load-serving entity to identify and assess errors, risks, and uncertainties in anticipation of potential new or enhanced environmental regulations.

APS monitors the regulatory and judicial landscape as potential environmental regulations evolve and become more clearly defined. APS reviews and updates cost estimates based on the latest information available and utilizes the services of outside engineering firms as appropriate. APS also comments, both through industry groups and independently, on regulations when they are proposed in order to help influence the final form of the regulation. The hypothetical cost of CO_2 is included in Table D8 in Rule D.2. That cost based upon the current California market Cap and Trade prices, because Congress has not yet taken action on this issue. As decision dates for finalized regulations approach, consistently more rigorous cost estimates are produced to mitigate the risk of uncertainty relating to potential new environmental regulations.

APS has access to renewable energy through the market as well as the integrated resource planning process. Within the resource planning process, renewable capacity additions are carefully planned, ensuring the resource is needed and it is procured to maintain reliability and affordability. The resource planning process also carefully considers public policy which may require that certain thresholds or milestones be met in a given timeframe. Access to the market provides an extra level of savings for customers by allowing APS to absorb low and negatively priced energy from its neighbors when renewable energy production is abundant. This is made possible by planning for a system that provides flexibility, allowing APS to reduce its own generation in order to allow room to absorb energy from the market. Renewable energy resources also help provide diversity to the APS portfolio and mitigate the dependency on fossil-fueled generation. Through thoughtful and carefully planned renewable energy resource additions, APS has set a goal to no longer use coal resources by 2031, significantly reducing CO_2 emissions from 2005 levels with the goal of becoming 100% clean by 2050.

RULE E.1(F)

Risk Identification: (f) changes in fuel prices and availability.

Coal for APS power plants is currently purchased under long-term contracts with fixed prices and inflation-related escalators. Should APS have the need to decrease coal deliveries to a level below coal contract terms, APS would likely be subject to liquidated damages for the amount of the coal that was contracted, but not taken. Risks for coal supply to power plants include rail service interruptions, mine permit extensions, and viability of coal mine operations driven by recent announcements of coal plant closures throughout the west.

Current natural gas supplies in North America are projected to last for the foreseeable future at the current levels of consumption. The primary reliability risk for natural gas supplies would be a disruption in natural gas pipeline transportation between the gas production basins and APS power plants. A disruption could involve extreme weather events and subsequent well-head freeze-off, pipeline rupture or lack of pipeline compression needed to move fuel through pipelines.

Natural gas pipeline capacity presents the greatest fuel risk to APS. While natural gas prices have dropped due to the abundant supply attributed to the shale revolution, available natural gas transportation in the Southwest is decreasing as domestic and Mexican demand for natural gas grows. Since 2013, Mexico has continually added substantial incremental subscriptions for long term gas capacity with pipeline networks in the Southwest and Texas. However, with California's aggressive RPS standards there is potential for some capacity to free up as transport contracts providing supply to California come up for renewal. APS monitors future demand growth and current pipeline infrastructure to determine any shortfalls for the next five years.

In order to identify how natural gas transportation availability will affect future demand growth, APS performed a Natural Gas Infrastructure Strategy assessment in 2019. APS utilizes information from the study performed by Concentric and analyzes this against various growth models developed by APS. The information compares current pipeline contracts with total pipeline capacity and forecasts future transportation availability in the 5-10-year period. In order to quantify how natural gas price fluctuation risk would impact the portfolios, APS performs gas price sensitivity analyses. APS evaluates natural gas generation based on the Energy Information Administration's (EIA) projection in the EIA 2020 Annual Energy Outlook. Using EIA's outlook, the sensitivity assumes 75% higher and 23% lower natural gas prices in order to evaluate changes in relative position of natural gas units to other technologies.

RULE E.2(F)

Risk Analysis: (f) changes in fuel prices and availability.

The primary means for managing fuel price and supply risk include contracting for longer periods, contracting under fixed price arrangements, utilizing multiple vendors, and engaging in hedging activity. The primary means for managing exposure to any one particular type of fuel is to develop and maintain a diverse portfolio of resources that does not overly depend on any one fuel source.

Coal is typically contracted for under longer-term supply arrangements. Coal supply agreements contain provisions that provide supply and price protections in the event of a shortfall. APS also assesses alternative sources of coal that could be executed in the event of supply shortfall.

Natural gas supply is typically contracted for under shorter-term fuel supply arrangements. Even though natural gas supplies are typically contracted on a shorter-term basis, prices may be locked in for longer periods of time using forward financial swap instruments or futures contracts that lock in prices for specified delivery periods in the future.

Natural gas transportation is typically contracted for using fixed rates under longer-term arrangements. Additional gas transport capabilities are developed as necessary based on as-needed firm contract requests. The sequence of pipeline infrastructure build-out follows this general sequence:

- Gas customer recognizes a need for additional transport need. An APS example may be due to the construction of a new natural gas generation facility or the signing of a new gas PPA.
- The gas customer makes a decision on whether this new gas capability should be a firm delivery or interruptible based on a variety of factors including economics, reliability requirements, and appetite for volatility of prices or delivery. APS contracts for only firm transport based on APS business model and reliability responsibilities.
- The gas customer negotiates with gas transportation supplier(s) for the appropriate services based on each suppliers list of services and customer needs. These services differ based on carrier.
- When a firm transport contract is requested that is beyond the existing natural gas infrastructure capabilities, it triggers an infrastructure build-out study and balance of cost, capability, type, etc. Typical examples include adding additional horsepower to existing compressor stations, adding compressor stations or adding new transport pipeline.

- The lead time and cost of additions is dependent on the stated need (firm contract request), availability of options to satisfy the need, and securing needed regulatory permits or approvals.

Following this process, APS recently firmed gas transport needs through 2024 to resolve capacity needs for SouthPoint gas PPA starting in the summer of 2021. As more renewable resources and battery storage are added to the APS portfolio the need for incremental transport moving forward will lessen. Renewals of existing contracts will be closely evaluated on an on-going basis and will be expired as the loads and resource mix evolves.

RULE E.3(F)

Risk Mitigation Plan: (f) changes in fuel prices and availability.

Coal for APS power plants is currently purchased under long-term contracts with fixed price adjustments. APS benefits from coal suppliers having sources with proven reserves well in excess of what could be needed even beyond the Planning Period. Disruption of coal supply due to rail interruptions is managed by keeping additional inventory of coal on power plant sites. In order to accommodate interruptions in coal supply, APS typically maintains a 45-day reserve of coal at the Cholla plant and a 60-day reserve of coal at the Four Corners plant.

For the Cholla Power Plant, transportation for coal is provided through firm long-term contracts with the Burlington Northern Santa Fe Railway. In the case of the Four Corners Power Plant, the coal mine is located adjacent to Four Corners, mitigating the risk of rail disruptions and providing alternate transportation options such as trucking.

APS mitigates the risk of disruption in gas supply due to pipeline interruptions by contracting for natural gas transportation through long-term firm contracts over three separate pipelines – El Paso Natural Gas, TC Energy (North Baja), and Transwestern, to transport 100% of the gas needed to meet the system peak generation demand. An example of this planning can be found in Attachment D.16. In addition, APS benefits from dual pipeline supply capability at the following power plants: Redhawk, Yucca, Sundance, Arlington, and Griffith (starting in the summer of 2020). All other power plants are served by the El Paso or North Baja pipelines. Individual pipeline risk to those plants is mitigated since El Paso pipeline utilizes a redundant system that consists of multiple pipes. Additional pipes mitigate risk of a single pipe rupture since remaining pipes could continue operating.

In order to manage natural gas price volatility risk, APS employs a five-year hedge plan. The hedging parameters are 85% for year 1, 55% for year 2, 45% for year 3, 30% for year 4 and 15% for year 5. In hedging fuel supplies and prices, APS utilizes many different creditworthy counterparties to reduce concentration risk of a counterparty failing to perform their contractual obligations.

Nuclear refueling outages normally avoid the summer months to meet the peak demand for power. Sufficient fuel is maintained on-site to meet the summer peak demand periods.

RULE E.1(G)

Risk Identification: (g) construction costs, capital costs, and operating costs.

The primary construction, capital, and operating cost risks are associated with the engineering, procurement, and construction (EPC) of new generating units. Engineering, procurement, and construction of modifications to generating units also have similar risks but the total costs at risk are typically smaller.

There are many factors that have the potential to negatively impact cost, scope, and schedule of construction projects. These factors include but are not limited to the following:

- Escalating material or labor costs beyond what has been anticipated;
- Force majeure, inclement weather, labor strikes, craft availability, productivity risks;
- Federal, state or municipality permitting process;
- Quality assurance failure of one-of-a-kind engineered equipment or failure to pass customer and factory acceptance tests;
- Major equipment performance failure to operate at minimum guaranteed ratings;
- Material availability issues due to industry shift in technology selection; and,
- Contractor non-performance.

In addition, if land acquisition is a prerequisite to a construction project, there are potential risks. Acquisition of private land is systematic and is approached with an offer letter, appraisal, and negotiations. Timing is critical to managing risk if condemnation is necessary and a court settlement is required. Generally, a timeframe of 2 years is estimated for land acquisition if condemnation is necessary.

Federal and state lands are secured through leases, or rights-of-way with each agency. Federal lands require a NEPA process that includes archaeological and biological studies for project impacts to threatened and endangered species. The estimated processing timeframe for a typical right-of-way application with Arizona State Land Department requires 24 months. A federal application (such as with the Forest Service or Bureau of Land Management) will typically require 36 months or longer, depending on impacts to species or archaeological sites.

RULE E.2(G)

Risk Analysis: (g) construction costs, capital costs, and operating costs.

Methods for managing risks and uncertainties include requiring liquidated damage provisions in contracts for EPC activities so as to mitigate the risk of various scenarios that may impact cost and schedule. Vendor selection is key; contracting with an experienced EPC that takes responsibility for and has a proven track record with the total design, including equipment integration, mitigates risks that all of the process system components will fit and work together when the project is commissioned. The risks of long-term reliability and maintainability are also mitigated by ensuring that personnel with power plant engineering and operations experience are integrated in the design review process.

Not all schedule impacts may be mitigated, however, especially if the impact is due to one-of-a-kind specifically engineered and manufactured equipment being damaged beyond repair or lost during shipping. Typically, this risk is mitigated through purchasing of insurance for compensation of loss. It is also beneficial to include project milestones to document progress and determine contractor performance to those milestones.

To ensure vendors have the capability to perform the scope of work expected, a vendor analysis may be completed prior to contracting for services. Vendor analysis includes an examination of experience and capability to perform, as well as a thorough credit analysis to help determine which vendors have the financial capability to perform. As a result of this review, it may be appropriate to request letters of credit or other performance guarantees to serve as collateral from vendors. If a vendor fails to perform required services, they must forfeit any collateral they have provided.

When it is determined that equipment replacement or modifications are needed, it is important that project processes and controls are in place, well documented and communicated in order to guide project work, set expectations and measure progress against project milestones. Project control processes include the review of Environmental and Critical Infrastructure Protection regulations in order to ensure technology choices are meet or exceed regulatory requirements.

When the need to retire, expand or build new generating assets is the planned course of action, external stakeholder analysis is an integral part of the planning process. Project control documents that are well communicated and measured against help serve to mitigate project cost and schedule risk.

In addition to vendor analysis and project control documents, it is also possible to conduct sensitivity analyses on project component costs to determine the overall magnitude of potential cost uncertainty. Sensitivities may be helpful in highlighting those cost components with the greatest potential to impact overall project cost uncertainty.

RULE E.3(G)

Risk Mitigation Plan: (g) construction costs, capital costs, and operating costs.

In the event of a delay in completing individual project tasks or in receiving project components, APS analyzes the overall project schedule to determine if the schedule can be reworked to avoid direct impact on the overall project completion date. Schedules are regularly analyzed for existing or potential problems that would affect the schedule or cost. The frequency of schedule analysis will vary from as often as daily to as infrequently as monthly depending on the type, complexity and phase of the project. APS uses schedule analysis and progress measurement to identify potential risks as early as possible. Identifying potential delays as early as possible improves the probability that a corrective action or contingency plan will have the desired effect of maintaining originally scheduled completion dates.

Examples of schedule impacts and actions to mitigate include:

- **Construction completion after contract completion date –** This risk is normally mitigated by regular schedule reviews and progress milestone measurement. APS also mitigates this risk by including contract provisions for liquidated damages, whereby vendors must forfeit collateral to APS in the event of missing contractually-agreed-to milestones or completion dates.
- **Contractor productivity less than planned due to factors such as inclement weather, labor strikes, and craft availability –** In many instances, this risk is mitigated by requesting an increase in the number of critical craft personnel on site or the number of shifts being worked to return to the original completion schedule.
- **Permitting delays –** This risk may result from the need to satisfy local aesthetic or other preferences in order to obtain municipal construction permits; address concerns of non-governmental organizations or other interveners in order to obtain environmental permits. To mitigate this risk, APS is an active participant in Federal, state, local community and regulatory forums which enables a project team to identify external stakeholders concerns early and incorporate into project timelines and budgets.
- **Equipment delivery delays –** Some negative schedule impacts cannot be totally recovered. Examples are when one-of-a-kind specifically engineered and manufactured equipment is lost or damaged during shipping to the construction site. To mitigate this risk, APS purchases insurance to compensate for a potential loss of this nature.

Impacts from uncertainties are mitigated by the regular review and updating of project plans and cost estimates based on the latest industry information available. As the project start date approaches, consistently more rigorous cost estimates are produced to reduce the level of cost uncertainty.

In addition to assessing capital cost risk pertaining to the construction and installation of facilities, as well as land, land rights, structures, and equipment, APS also includes an allowance for funds used during construction in its capital cost estimates.

When it is determined that equipment replacements or modifications at existing power plants are required to improve plant efficiency or reliability, or to comply with new environmental regulations, APS has guidelines which are used to establish consistent, orderly and efficient inter-discipline and inter-department communication for these projects. The project guidelines establish the level of project control needed to reduce the project risks, which could in turn increase costs or delay project completion.

Very large projects of sufficient size are controlled in a similar fashion; however, these projects may be so large and demanding that a new project organization with a separate dedicated staff will be created for the duration of the project.

Where capital or fuel costs can represent up to 75% of the total delivered cost of power for many technologies, non-fuel operating costs generally represent less than 10% of the delivered cost. Consequently, the sensitivity of power costs to non-fuel operating costs is typically far less than it is to capital or fuel.

RULE E.1(H)

Risk Identification: (h) other factors the load-serving entity wishes to consider.

Several risks, uncertainties and errors have been discussed independently in Rules E(a) through E(g) above. APS has chosen to consider these and other parameters in tandem with each other by creating four portfolios and performing six sensitivities on the three portfolios that meet its clean energy commitment goals. Assumptions were varied around the following parameters: economic outlook including load growth, potential carbon costs and gas prices.

RULE E.2(H)

Risk Analysis: (h) other factors the load-serving entity wishes to consider.

Three resource portfolios that meet the APS clean energy commitment goals were each evaluated under all six scenarios in order to assess their robustness, or ability to perform under different circumstances. They were evaluated in terms of their fuel diversity, capital expenditure requirements, gas burn, revenue requirements, carbon emissions and water consumption. Please see Chapter 7 for results of the sensitivity analysis.

RULE E.3(H)

Risk Mitigation Plan: (h) other factors the load-serving entity wishes to consider.

Due to the inherent risks in future scenarios, APS has mitigated risk by bringing forward three portfolios that meet its clean energy commitment. As it gains clarity around the uncertain variables, the Company can align with the portfolio that provides the best outcome for customers through updates to the Action Plan. For a complete discussion about the portfolios, scenarios or risks, APS analysis and results, please refer to Chapter 7.

RESPONSE TO RULES

SECTION F
2020 IRP

RESPONSE TO RULES SECTION F – 2020 IRP

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(F), which specifically requires information related to the selected 15-year resource plan.

RULE F.1

Selects a portfolio of resources based upon comprehensive consideration of a wide range of supply – and – demand-side options.

In creating the 2020 IRP, APS analyzed four distinct portfolios for consideration composed of a mixture of technologies (as described further in Attachment D.3). APS monitored how each portfolio performed based on certain key metrics, including: renewable penetration; carbon emissions; natural gas burn; NPV of revenue requirements; cumulative capital expenditures; and water use. APS then created scenarios and stressed several key input variables on three of the four portfolios, such as natural gas prices, carbon costs and load growth, to determine the robustness of each portfolio. The results of the analytics can be found at:

- Attachment F.1(a) – Analysis of three Portfolios (Loads and Resources Tables and Energy Mixes)
- Attachment F.1(b) – Analysis of three Portfolios (Key Metrics)

Description of portfolios and sensitivities can be found in Chapter 7.

RULE F.2

Will result in the load-serving entity's reliably serving the demand for electric energy services.

Each of the three portfolios presented in the 2020 IRP are designed to provide reliable power to its customers with the required operating reserves while allowing for unforeseen events such as higher-than-forecast customer demand and forced outages of several generators at one time. APS uses an LOLP reliability criterion of one day of outage in ten years to provide the desired level of reliability. While there is not a standard prescribed by the WECC or NERC, a 1-in-10 LOLP is a common standard in the industry. APS has found that designing resource portfolios based on a 15% reserve margin provides better than 1-in-10 LOLP. APS's 2020 Resource Plans maintain a 15% or greater planning reserve margin for each year of the 15-year Planning Period as indicated in response to Rule D1(b)-B.2(e).

In addition to the reliability discussed above, APS also performs a Reliability Must Run (RMR) study of its Phoenix and Yuma load pockets every two years as part of the ACC's Biennial Transmission Assessment. This study specifically looks at transmission-constrained load pockets and is done in conjunction with Southwest Area Transmission and other Arizona utilities. The last report, filed in January 2012, indicated that planned transmission along with existing transmission and local generation will be sufficient to provide better than 1-in-10 LOLP for the years studied. Because conditions had not changed appreciably since the 2012 filing, an RMR study was not required for the 2020 filing.

RULE F.3

Will address the adverse environmental impacts of power production.

Arizona's water challenges balance increasing demand for water due to high growth rates and limited supply of water given the arid conditions of the Desert Southwest. Towards that end, each APS power plant has a unique water strategy, which is developed to promote efficient and sustainable use of water. Other water conservation efforts over the 2020-2035 Planning Period include retiring or upgrading existing water-intensive power plants, increasing the use of renewable energy that does not use water (wind and PV solar) and implementing DSM programs.

APS strives to cost-effectively reduce the impact of its operations on the environment and communities that it serves. During the past Action Plan Period, APS completed (a) the installation of state-of-the-art air pollution controls at the Four Corners Power Plant, (b) the replacement of older gas-fired turbines with new, modern turbines and modernized air pollution controls as part of the Ocotillo Modernization Project, and (c) the installation of upgraded combustion technology that increased output from the Redhawk Power Plant without increasing emissions of nitrogen dioxide.

Rule D.17, details APS's plans to reduce environmental impacts related to a) air emissions and solid waste to ensure full compliance with known environmental regulations and b) regulations impacting water and a plan for reducing impacts. The Bridge, Shift and Accelerate portfolios also include significant amounts of energy efficiency and renewable energy – resources that provide energy to APS with limited adverse environmental impacts. This allows for a 47% increase in customer load sales prior to energy efficiency and distributed energy, while CO2 emission intensity and annual water use intensity decreases 70%-87% and 49%-58%, respectively, over the 15-year Planning Period. For more details about environmental impacts for multiple emissions and water consumption for the three portfolios, see Attachment D.1(a)(8).

RULE F.4

Will include renewable energy resources so as to meet or exceed the greater of the Annual Renewable Energy Requirement in R14-2-1804 or the following annual percentages of retail kWh sold by the load-serving entity.

As indicated in Table F-1 below, each of the three portfolios presented in the 2020 IRP exceeds the amount of renewable energy required under the ACC RES for all years during the Planning Period. Note that in addition to the RES requirement, APS was required to achieve 1,700,000 MWh of incremental renewable generation by December 31, 2015, per ACC Decision No. 71448.

The percentages for renewable energy production presented in Table F-1 do not include market purchases of renewable energy. Given the current trend, APS is anticipating the opportunity to continue to take advantage of the regional excess supply of solar through the market.

TABLE F-1. RENEWABLE GENERATION INCLUDED IN 2020 BRIDGE, SHIFT AND ACCELERATE PORTFOLIOS

CALENDAR YEAR	ACC RES REQUIREMENT (PERCENT OF RETAIL SALES DURING CALENDAR YEAR)	RENEWABLE GENERATION IN APS 2020 BRIDGE PORTFOLIO	RENEWABLE GENERATION IN APS 2020 SHIFT PORTFOLIO	RENEWABLE GENERATION IN APS 2020 ACCELERATE PORTFOLIO
2020	10.0%	16.5%	16.6%	16.6%
2021	11.0%	16.6%	16.6%	16.6%
2022	12.0%	19.5%	19.5%	19.5%
2023	13.0%	23.0%	23.0%	23.4%
2024	14.0%	25.0%	25.0%	25.3%

TABLE F-1. RENEWABLE GENERATION INCLUDED IN 2020 BRIDGE, SHIFT AND ACCELERATE PORTFOLIOS (CONTINUED)

CALENDAR YEAR	ACC RES REQUIREMENT (PERCENT OF RETAIL SALES DURING CALENDAR YEAR)	RENEWABLE GENERATION IN APS 2020 BRIDGE PORTFOLIO	RENEWABLE GENERATION IN APS 2020 SHIFT PORTFOLIO	RENEWABLE GENERATION IN APS 2020 ACCELERATE PORTFOLIO
2025	15.0%	32.0%	31.9%	31.8%
2026	15.0%	34.7%	34.7%	38.7%
2027	15.0%	37.5%	37.9%	44.0%
2028	15.0%	38.3%	40.6%	46.6%
2029	15.0%	41.0%	43.5%	52.6%
2030	15.0%	45.5%	45.5%	51.7%
2031	15.0%	48.7%	53.3%	62.9%
2032	15.0%	51.0%	56.9%	69.1%
2033	15.0%	53.8%	59.8%	72.2%
2034	15.0%	55.6%	62.4%	75.0%
2035	15.0%	58.3%	65.6%	77.1%

RULE F.5

Will include distributed generation energy resources so as to meet or exceed the greater of the Distributed Renewable Energy Requirement in R14-2-1805 or the following annual percentages as applied to the load-serving entity's Annual Renewable Energy Requirement.

The Distributed Renewable Energy Requirement in R14-2-1805 and the annual percentages in the Resource Planning Rules are the same and have been set at 30% since 2011. As indicated in Table F-2 the distributed energy represented in the 2020 Resource Plan meets or exceeds the requirements in all years of the Planning Period.

TABLE F-2. DISTRIBUTED RENEWABLE ENERGY INCLUDED IN THE 2020 RESOURCE PLAN (BRIDGE, SHIFT & ACCELERATE)

CALENDAR YEAR	DISTRIBUTED GENERATION REQUIREMENT (PERCENT OF ANNUAL RENEWABLE REQUIREMENT)	DISTRIBUTED GENERATION IN APS 2020 RESOURCE PLAN (PERCENT OF ANNUAL RENEWABLE REQUIREMENT)
2020	30%	76%
2021	30%	72%
2022	30%	67%
2023	30%	63%
2024	30%	60%
2025	30%	58%
2026	30%	59%
2027	30%	61%
2028	30%	63%
2029	30%	65%
2030	30%	67%
2031	30%	69%
2032	30%	71%
2033	30%	73%
2034	30%	75%
2035	30%	76%

RULE F.6

Will address energy efficiency so as to meet any requirements set in rule by the Commission, or in an order of the Commission.

ACC Decision No. 71819 set forth Energy Efficiency Requirements, which became effective January 1, 2011. Energy Efficiency represented in the each of the three portfolios presented in the 2020 IRP meets the 2020 EE Standard set in Decision No. 75679.

TABLE F-3. CUMULATIVE ENERGY EFFICIENCY BY YEAR % OF RETAIL SALES

Cumulative Energy Efficiency		
CALENDAR YEAR	ACC DECISION NO. 71819 EE STANDARD (PERCENTAGE OF RETAIL SALES)	EE INCLUDED IN APS 2020 RESOURCE PLAN
2020	22.00%	23.66%

RULE F.7

Will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors.

As described in response to Rule F.1, APS performed a rigorous series of analytics on all of the potential portfolios under consideration. By expanding its position in renewable energy and its plans to increase energy storage, APS is reducing fuel price volatility and risk by diversifying the portfolio. Natural gas will remain in the portfolio, mainly as a bridge resource, as the Company develops the resources it needs to remove all of the carbon from its system by 2050. Over time, APS will retire or convert its natural gas plants, removing fuel price risk all-together.

Regardless of fuel price outcomes, APS relies on the output of Palo Verde Nuclear Generation Station to maintain a reliable and diverse low carbon mix of resources. APS also manages future cost and environmental risks by either assuming compliance or exceeding the EE Standard and the RES. Environmental risk is further mitigated with APS's clean energy commitment of 100% clean energy by 2050, eliminating emissions all together. Finally, APS has significant flexibility in how it meets future load forecast fluctuations by relying on resources that have relatively short development lead times, such as solar plus energy storage, wind, existing generation resources in the region and market purchase opportunities for energy, as well as relying upon the 15% reserve margin.

RULE F.8

Will achieve a reasonable long-term total cost, taking into consideration the objectives set forth in subsections (F)(2)-(7) and the uncertainty of future costs.

The Bridge, Shift and Accelerate portfolios of the 2020 IRP, as outlined in Attachment F.9(b), meet the objectives set forth in Rules F.2 thru F.7 of the Resource Planning Rules, and are each expected to achieve a reasonable long-term cost as shown in Attachment D.10. Each of the three portfolios contain fuel- and technology-diverse resources that meet or exceeds reliability criteria, the EE Standard, the RES and manage risk through the planning of flexible resource options and limiting exposure to natural gas prices and carbon emissions. As the future unfolds and conditions change, these portfolios can be easily modified to address changes. They provide road maps for the future and will guide APS procurement efforts. Those efforts will ultimately result in the specific choices of resources to meet APS customer energy needs in a manner that balances reliability, cost, the environment and risk.

RULE F.9(A)

Contains all of the following: (a) a complete description and documentation of the plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized.

A complete description and documentation of the plan are contained in the following sections of this report:

- **Supply Conditions:** All of the elements of APS's existing resource portfolio, including owned generation and purchase power contracts, are described and documented in the responses to Rule D.1. Information related to energy efficiency measures is included in the responses to Rule D.14.
- **Demand Conditions:** Customer demand conditions are provided and documented in the responses to Rules C.1, C.2, and C.3.
- **Availability of Transmission:** Transmission necessary to ensure availability for resource delivery is discussed in the responses to Rules D.1(b), D.1(d), D.1(f), D.1(g), and D.10.
- **Costs:** Costs of individual supply-side resource technologies are contained in the response to Rules D.1 and D.3, while costs of individual demand side management measures are contained in the response to Rule D.14. Costs and system revenue requirements associated with the 2014 Resource Plan are contained in Attachment D.10.
- **Discount Rate:** APS uses 7.57%, the Company's after-tax weighted cost of capital, as its discount rate.

RULE F.9(B)

Contains all of the following: (b) a comprehensive, self-explanatory load and resources table summarizing the plan.

The loads and resources tables are provided at Attachment F.9(b).

RULE F.9(C)

Contains all of the following: (c) a brief executive summary.

The Executive Summary is included at the beginning of this document.

RULE F.9(D)

Contains all of the following: (d) an index to indicate where the responses to each filing requirement of these rules can be found.

APS has included a high-level Table of Contents for this document and its related Attachments and Appendices throughout this document.

RULE F.9(E)

Contains all of the following: (e) definitions of the terms used in the plan.

The definitions of the terms used in the filing are contained in the Glossary included herein.

RESPONSE TO RULES

SECTION H
ACTION PLAN

RESPONSE TO RULES SECTION H – ACTION PLAN

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(H), which specifically requires information related to the Action Plan for the following three-year period.

RULE H.1-H.3

Includes a summary of actions to be taken on future resource acquisitions; Includes details on resource types, resources capacity, and resource timing; Covers the three-year period following the Commission's acknowledgement of the resource plan.

This response is included in Chapter 8.

RESPONSE TO RULES

SECTION I
OTHER FACTORS

RESPONSE TO RULES SECTION I – OTHER FACTORS

Resource Planning Rule A.A.C. R14-2-703 sets forth the reporting requirements for a load-serving entity. The following items provide responses to section R14-2-703(I), which allows the utility to provide additional information related to environmental impacts for the Commission's considerations.

RULE I

A load-serving entity or any interested parties may also provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be developed and reviewed by the Commission in other proceedings or stakeholder workshops.

APS has included data related to environmental impacts of each of the Company's three portfolios represented in the 2020 IRP in multiple locations within this document. Environmental issues and water usage are discussed in Chapter 1. Environmental plans are discussed at length in response to Rules D.17, E.1(d)-E.3(d), and E.1(e)-E.3(e). A table of emissions for each generator is found at Attachment D.1(a)(8). Attachment F.1(b) contains information for model runs performed in support of this resource plan.

ATTACHMENTS

TABLE OF ATTACHMENTS

Indicates Confidential Information

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS

PEAK DEMAND (MW)													
YEAR: 2020	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,070	1,959	1,750	2,179	2,775	3,810	4,124	4,154	3,438	2,319	1,494	2,001	4,124
Comm+Ind <3 MW	1,522	1,473	1,406	1,563	1,709	2,125	2,357	2,358	2,323	2,063	1,555	1,471	2,357
Comm+Ind >3 MW	365	381	374	385	377	441	478	428	419	419	374	321	478
Irrigation	1	0	1	1	1	2	2	1	1	1	1	1	2
Streetlights	18	7	11	0	0	0	0	0	0	1	1	6	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	3,976	3,821	3,541	4,128	4,863	6,378	6,960	6,941	6,181	4,802	3,425	3,799	6,960
Losses On Peak	275	264	244	284	331	433	473	472	423	329	236	263	473
Total Own Load Peak	4,251	4,085	3,785	4,412	5,193	6,811	7,411	7,413	6,604	5,131	3,661	4,062	7,411
Energy Efficiency Programs	(23)	(18)	(31)	(45)	(79)	(116)	(125)	(120)	(82)	(63)	(26)	(20)	(125)
Distributed Energy Programs	0	(4)	0	(2)	(26)	(31)	(7)	(29)	(13)	(10)	0	0	(7)
Own Load After EE/DE	4,227	4,063	3,755	4,365	5,088	6,663	7,278	7,264	6,510	5,057	3,635	4,042	7,278

PEAK DEMAND (MW)													
YEAR: 2021	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,081	2,061	1,851	2,258	2,872	3,938	4,281	4,292	3,570	2,414	1,551	2,077	4,292
Comm+Ind <3 MW	1,530	1,550	1,487	1,620	1,768	2,196	2,447	2,436	2,412	2,148	1,614	1,527	2,436
Comm+Ind >3 MW	367	401	395	399	390	456	437	442	435	436	389	333	442
Irrigation	1	0	1	1	1	2	2	1	1	1	1	1	1
Streetlights	19	7	12	0	0	0	0	0	0	1	1	7	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	3,997	4,020	3,746	4,279	5,032	6,592	7,167	7,171	6,419	5,000	3,555	3,944	7,171
Losses On Peak	275	277	258	289	337	440	479	480	429	338	245	272	480
Total Own Load Peak	4,272	4,297	4,004	4,568	5,369	7,032	7,646	7,650	6,848	5,339	3,800	4,215	7,650
Energy Efficiency Programs	(43)	(33)	(35)	(105)	(146)	(213)	(227)	(220)	(197)	(115)	(25)	(37)	(220)
Distributed Energy Programs	0	(7)	0	(22)	(45)	(53)	(54)	(51)	(52)	(18)	(5)	0	(51)
Own Load After EE/DE	4,229	4,258	3,969	4,442	5,179	6,765	7,365	7,379	6,600	5,205	3,770	4,178	7,379

PEAK DEMAND (MW)													
YEAR: 2022	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,167	2,138	1,925	2,348	2,985	4,071	4,421	4,432	3,702	2,494	1,616	2,153	4,432
Comm+Ind <3 MW	1,594	1,608	1,546	1,685	1,838	2,270	2,527	2,515	2,501	2,219	1,682	1,583	2,515
Comm+Ind >3 MW	382	416	411	415	406	471	451	456	451	450	405	345	456
Irrigation	1	0	1	1	1	2	2	1	1	1	1	1	1
Streetlights	19	7	12	0	0	0	0	0	0	1	1	7	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	4,163	4,170	3,896	4,449	5,231	6,815	7,401	7,405	6,656	5,166	3,704	4,089	7,405
Losses On Peak	285	286	266	297	346	447	487	488	441	346	253	281	488
Total Own Load Peak	4,448	4,456	4,162	4,746	5,578	7,263	7,888	7,893	7,097	5,512	3,957	4,369	7,893
Energy Efficiency Programs	(62)	(47)	(65)	(152)	(212)	(310)	(304)	(320)	(263)	(168)	(69)	(54)	(320)
Distributed Energy Programs	0	(9)	0	(28)	(36)	(72)	(95)	(66)	(46)	(23)	0	0	(66)
Own Load After EE/DE	4,386	4,400	4,097	4,566	5,330	6,881	7,488	7,506	6,788	5,321	3,887	4,315	7,506

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2023	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,244	2,215	1,998	2,428	3,094	4,200	4,561	4,572	3,811	2,573	1,680	2,228	4,572
Comm+Ind <3 MW	1,650	1,665	1,605	1,743	1,905	2,342	2,607	2,595	2,575	2,289	1,749	1,638	2,595
Comm+Ind >3 MW	396	431	426	429	421	486	465	471	464	464	421	357	471
Irrigation	1	0	1	1	2	2	2	1	1	2	1	1	1
Streetlights	20	8	13	0	0	0	0	0	0	1	1	7	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	4,311	4,319	4,043	4,602	5,421	7,031	7,636	7,639	6,851	5,328	3,852	4,231	7,639
Losses On Peak	294	295	276	304	358	454	499	501	450	353	261	289	501
Total Own Load Peak	4,605	4,614	4,320	4,905	5,779	7,486	8,135	8,140	7,301	5,681	4,113	4,520	8,140
Energy Efficiency Programs	(82)	(62)	(67)	(200)	(271)	(407)	(434)	(353)	(345)	(220)	(91)	(70)	(353)
Distributed Energy Programs	0	(11)	0	(31)	0	(88)	(21)	(82)	(36)	(30)	0	0	(82)
Own Load After EE/DE	4,523	4,541	4,253	4,675	5,509	6,990	7,680	7,705	6,920	5,432	4,022	4,449	7,705

PEAK DEMAND (MW)													
YEAR: 2024	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,326	2,259	2,033	2,521	3,189	4,321	4,706	4,715	3,935	2,675	1,736	2,306	4,715
Comm+Ind <3 MW	1,711	1,699	1,633	1,809	1,964	2,410	2,690	2,676	2,658	2,380	1,807	1,695	2,676
Comm+Ind >3 MW	410	440	434	445	434	500	480	485	479	483	435	370	485
Irrigation	1	1	1	1	2	2	2	1	1	2	1	1	1
Streetlights	21	8	13	0	0	0	0	0	0	1	1	7	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	4,469	4,406	4,114	4,777	5,589	7,234	7,878	7,879	7,074	5,540	3,979	4,379	7,879
Losses On Peak	304	300	277	312	369	461	508	512	459	364	269	298	512
Total Own Load Peak	4,773	4,706	4,391	5,089	5,958	7,695	8,387	8,390	7,533	5,904	4,248	4,677	8,390
Energy Efficiency Programs	(101)	(77)	(133)	(247)	(277)	(504)	(470)	(413)	(427)	(272)	(113)	(87)	(413)
Distributed Energy Programs	0	(14)	0	(36)	0	(95)	(97)	(102)	(45)	(37)	0	0	(102)
Own Load After EE/DE	4,672	4,616	4,258	4,806	5,681	7,096	7,820	7,876	7,061	5,595	4,135	4,590	7,876

PEAK DEMAND (MW)													
YEAR: 2025	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,409	2,372	2,135	2,607	3,291	4,468	4,852	4,867	4,050	2,763	1,798	2,385	4,852
Comm+Ind <3 MW	1,772	1,784	1,715	1,871	2,026	2,492	2,773	2,763	2,736	2,458	1,871	1,753	2,773
Comm+Ind >3 MW	425	462	456	461	447	517	495	501	493	499	451	383	495
Irrigation	1	1	1	1	2	2	2	1	1	2	1	1	2
Streetlights	21	8	14	0	0	0	0	0	0	1	1	8	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	4,628	4,627	4,320	4,940	5,766	7,479	8,123	8,133	7,281	5,723	4,121	4,529	8,123
Losses On Peak	315	315	293	322	376	471	518	514	463	372	280	309	518
Total Own Load Peak	4,943	4,942	4,613	5,262	6,141	7,950	8,641	8,647	7,744	6,095	4,402	4,838	8,641
Energy Efficiency Programs	(100)	(78)	(111)	(272)	(364)	(600)	(637)	(615)	(523)	(331)	(78)	(90)	(637)
Distributed Energy Programs	0	(17)	0	(31)	0	(110)	(33)	(124)	(100)	(45)	(13)	0	(33)
Own Load After EE/DE	4,842	4,847	4,501	4,959	5,778	7,241	7,971	7,907	7,121	5,718	4,311	4,748	7,971

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2026	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,479	2,451	2,216	2,676	3,393	4,622	5,000	5,016	4,160	2,836	1,863	2,468	5,000
Comm+Ind <3 MW	1,823	1,844	1,779	1,920	2,089	2,578	2,858	2,847	2,811	2,523	1,939	1,814	2,858
Comm+Ind >3 MW	437	477	473	473	461	535	510	517	507	512	467	396	510
Irrigation	1	1	1	2	2	2	2	1	1	2	1	1	2
Streetlights	22	9	14	0	0	0	0	0	0	1	1	8	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	4,762	4,781	4,484	5,070	5,945	7,738	8,370	8,382	7,479	5,874	4,270	4,687	8,370
Losses On Peak	323	325	304	337	386	480	528	522	484	378	286	319	528
Total Own Load Peak	5,085	5,106	4,787	5,407	6,332	8,218	8,898	8,904	7,963	6,252	4,556	5,005	8,898
Energy Efficiency Programs	(116)	(91)	(114)	(227)	(387)	(695)	(667)	(713)	(455)	(384)	(162)	(104)	(667)
Distributed Energy Programs	0	(16)	0	0	0	(133)	(111)	(154)	(66)	(54)	0	0	(111)
Own Load After EE/DE	4,969	5,000	4,674	5,180	5,944	7,390	8,120	8,037	7,442	5,814	4,394	4,901	8,120

PEAK DEMAND (MW)													
YEAR: 2027	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,556	2,528	2,296	2,766	3,496	4,759	5,155	5,167	4,308	2,938	1,920	2,547	5,167
Comm+Ind <3 MW	1,880	1,901	1,844	1,985	2,153	2,654	2,946	2,933	2,911	2,614	1,998	1,872	2,933
Comm+Ind >3 MW	451	492	490	489	475	551	526	532	525	530	481	409	532
Irrigation	1	1	1	2	2	2	2	1	1	2	1	1	1
Streetlights	23	9	15	0	0	0	0	0	0	1	1	8	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	4,910	4,930	4,646	5,241	6,127	7,967	8,630	8,634	7,746	6,085	4,401	4,836	8,634
Losses On Peak	332	334	314	342	398	491	528	531	482	388	299	328	531
Total Own Load Peak	5,243	5,264	4,959	5,583	6,524	8,458	9,158	9,165	8,228	6,473	4,700	5,164	9,165
Energy Efficiency Programs	(133)	(104)	(134)	(326)	(404)	(792)	(841)	(812)	(634)	(437)	(89)	(119)	(812)
Distributed Energy Programs	0	(23)	0	0	0	(119)	(188)	(177)	(175)	(63)	(17)	0	(177)
Own Load After EE/DE	5,110	5,137	4,825	5,257	6,120	7,547	8,130	8,175	7,419	5,973	4,594	5,045	8,175

PEAK DEMAND (MW)													
YEAR: 2028	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,646	2,567	2,340	2,855	3,621	4,891	5,302	5,313	4,432	3,014	1,994	2,625	5,313
Comm+Ind <3 MW	1,946	1,930	1,879	2,048	2,230	2,728	3,031	3,016	2,994	2,681	2,075	1,929	3,016
Comm+Ind >3 MW	467	499	499	504	492	566	541	547	540	544	500	421	547
Irrigation	1	1	1	2	2	2	2	2	1	2	1	1	2
Streetlights	24	9	15	0	0	0	0	0	0	1	1	8	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	5,084	5,006	4,735	5,410	6,345	8,189	8,877	8,878	7,967	6,242	4,571	4,984	8,878
Losses On Peak	343	338	315	352	411	499	548	552	496	395	303	337	552
Total Own Load Peak	5,427	5,344	5,051	5,761	6,756	8,687	9,425	9,430	8,463	6,637	4,874	5,321	9,430
Energy Efficiency Programs	(149)	(116)	(199)	(351)	(439)	(887)	(804)	(735)	(748)	(490)	(200)	(133)	(735)
Distributed Energy Programs	0	(27)	0	0	0	(125)	(190)	(199)	(88)	(72)	(7)	0	(199)
Own Load After EE/DE	5,278	5,201	4,852	5,410	6,317	7,675	8,430	8,497	7,627	6,074	4,668	5,188	8,497

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2029	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,732	2,691	2,451	2,941	3,721	5,029	5,460	5,474	4,558	3,116	2,055	2,705	5,474
Comm+Ind <3 MW	2,009	2,024	1,968	2,110	2,291	2,804	3,121	3,107	3,079	2,772	2,139	1,988	3,107
Comm+Ind >3 MW	482	524	523	520	506	582	557	564	555	563	515	434	564
Irrigation	1	1	1	2	2	3	2	2	2	2	1	1	2
Streetlights	24	9	16	0	0	0	0	0	0	1	1	9	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	5,248	5,248	4,959	5,572	6,520	8,418	9,141	9,147	8,194	6,454	4,711	5,137	9,147
Losses On Peak	353	354	330	361	423	508	553	554	500	405	316	347	554
Total Own Load Peak	5,601	5,602	5,289	5,934	6,943	8,926	9,694	9,701	8,695	6,859	5,027	5,484	9,701
Energy Efficiency Programs	(165)	(129)	(187)	(373)	(438)	(986)	(774)	(1,011)	(720)	(544)	(152)	(148)	(1,011)
Distributed Energy Programs	0	(30)	(32)	0	0	(131)	(407)	(168)	(279)	(82)	(15)	0	(168)
Own Load After EE/DE	5,436	5,443	5,069	5,561	6,506	7,809	8,514	8,522	7,695	6,232	4,860	5,336	8,522

PEAK DEMAND (MW)													
YEAR: 2030	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,822	2,773	2,523	3,040	3,831	5,163	5,616	5,624	4,689	3,214	2,117	2,790	5,624
Comm+Ind <3 MW	2,076	2,086	2,026	2,181	2,359	2,879	3,209	3,192	3,168	2,859	2,203	2,051	3,192
Comm+Ind >3 MW	498	540	539	537	521	598	573	579	571	580	530	448	579
Irrigation	1	1	1	2	2	3	2	2	2	2	1	1	2
Streetlights	25	10	16	0	0	0	0	0	0	1	1	9	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	5,422	5,408	5,106	5,760	6,713	8,642	9,401	9,397	8,430	6,656	4,852	5,298	9,397
Losses On Peak	364	364	341	374	434	516	569	575	521	415	321	357	575
Total Own Load Peak	5,786	5,773	5,447	6,134	7,147	9,158	9,969	9,972	8,951	7,071	5,174	5,655	9,972
Energy Efficiency Programs	(181)	(142)	(195)	(387)	(471)	(1,083)	(909)	(872)	(913)	(598)	(223)	(163)	(872)
Distributed Energy Programs	0	(27)	0	0	0	(137)	(312)	(249)	(27)	(88)	(5)	0	(249)
Own Load After EE/DE	5,605	5,604	5,252	5,747	6,677	7,938	8,748	8,852	8,011	6,386	4,946	5,492	8,852

PEAK DEMAND (MW)													
YEAR: 2031	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,904	2,857	2,605	3,132	3,939	5,315	5,772	5,787	4,814	3,304	2,178	2,867	5,772
Comm+Ind <3 MW	2,136	2,148	2,092	2,247	2,425	2,964	3,299	3,285	3,252	2,940	2,267	2,108	3,299
Comm+Ind >3 MW	512	556	556	553	535	616	589	596	586	597	546	460	589
Irrigation	1	1	1	2	2	3	2	2	2	2	1	1	2
Streetlights	26	10	17	1	0	0	0	0	0	1	1	9	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	5,579	5,572	5,272	5,935	6,902	8,898	9,662	9,670	8,654	6,843	4,994	5,445	9,662
Losses On Peak	377	377	351	383	444	537	584	584	522	429	337	369	584
Total Own Load Peak	5,956	5,948	5,623	6,318	7,346	9,435	10,246	10,254	9,176	7,272	5,330	5,814	10,246
Energy Efficiency Programs	(149)	(113)	(221)	(423)	(519)	(1,080)	(1,155)	(1,124)	(877)	(641)	(147)	(131)	(1,155)
Distributed Energy Programs	0	(38)	0	0	0	(96)	(100)	(152)	(262)	(33)	(3)	0	(100)
Own Load After EE/DE	5,807	5,797	5,402	5,895	6,827	8,258	8,990	8,978	8,037	6,599	5,181	5,683	8,990

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2032	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	2,971	2,883	2,648	3,198	4,032	5,462	5,916	5,929	4,939	3,379	2,228	2,936	5,929
Comm+Ind <3 MW	2,185	2,168	2,127	2,295	2,483	3,046	3,381	3,365	3,337	3,006	2,319	2,158	3,365
Comm+Ind >3 MW	524	561	565	565	548	632	604	610	601	610	558	471	610
Irrigation	1	1	1	2	2	3	3	2	2	2	1	1	2
Streetlights	26	10	17	1	0	0	0	0	0	1	1	9	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	5,707	5,623	5,359	6,060	7,066	9,143	9,904	9,906	8,879	6,998	5,107	5,576	9,906
Losses On Peak	386	380	356	394	454	548	593	595	531	437	344	378	595
Total Own Load Peak	6,093	6,003	5,715	6,453	7,520	9,691	10,497	10,502	9,409	7,434	5,451	5,954	10,502
Energy Efficiency Programs	(161)	(122)	(239)	(399)	(538)	(1,159)	(1,239)	(1,209)	(934)	(691)	(150)	(141)	(1,209)
Distributed Energy Programs	0	(32)	0	0	0	(106)	(141)	(132)	(310)	(27)	(1)	0	(132)
Own Load After EE/DE	5,931	5,849	5,476	6,055	6,982	8,426	9,117	9,160	8,165	6,716	5,299	5,812	9,160

PEAK DEMAND (MW)													
YEAR: 2033	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	3,044	2,995	2,755	3,278	4,137	5,582	6,063	6,073	5,059	3,450	2,286	3,004	6,073
Comm+Ind <3 MW	2,239	2,253	2,212	2,352	2,547	3,113	3,465	3,447	3,418	3,070	2,379	2,208	3,447
Comm+Ind >3 MW	537	583	588	579	562	646	619	625	616	623	573	482	625
Irrigation	1	1	2	2	2	3	3	2	2	2	1	1	2
Streetlights	27	10	18	1	1	0	0	0	0	1	1	10	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	5,848	5,842	5,574	6,211	7,249	9,345	10,150	10,147	9,095	7,145	5,240	5,704	10,147
Losses On Peak	394	394	370	402	465	563	601	607	553	444	346	386	607
Total Own Load Peak	6,243	6,235	5,944	6,613	7,715	9,908	10,751	10,754	9,648	7,589	5,586	6,090	10,754
Energy Efficiency Programs	(174)	(131)	(257)	(425)	(555)	(1,238)	(1,090)	(1,298)	(1,010)	(745)	(265)	(152)	(1,298)
Distributed Energy Programs	0	(46)	0	0	0	(3)	(416)	(120)	(126)	(20)	0	0	(120)
Own Load After EE/DE	6,069	6,058	5,687	6,188	7,160	8,668	9,245	9,335	8,512	6,824	5,321	5,938	9,335

ATTACHMENT C.1(A): COINCIDENT PEAK DEMAND BY MONTH AND CUSTOMER CLASS (CONTINUED)

PEAK DEMAND (MW)

YEAR: 2034	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	3,114	3,065	2,825	3,350	4,243	5,715	6,207	6,214	5,161	3,523	2,344	3,071	6,214
Comm+Ind <3 MW	2,291	2,305	2,269	2,404	2,613	3,187	3,548	3,527	3,487	3,135	2,440	2,258	3,527
Comm+Ind >3 MW	549	596	603	592	577	662	633	640	629	636	587	493	640
Irrigation	1	1	2	2	2	3	3	2	2	2	1	1	2
Streetlights	28	11	18	1	1	0	0	0	0	1	1	10	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	5,983	5,979	5,717	6,348	7,435	9,567	10,391	10,383	9,279	7,297	5,374	5,833	10,383
Losses On Peak	403	402	378	411	476	565	616	627	566	451	354	394	627
Total Own Load Peak	6,386	6,381	6,095	6,759	7,911	10,131	11,007	11,010	9,845	7,748	5,728	6,227	11,010
Energy Efficiency Programs	(186)	(141)	(276)	(443)	(591)	(1,324)	(1,249)	(1,136)	(1,135)	(797)	(276)	(163)	(1,136)
Distributed Energy Programs	0	(49)	0	0	0	(119)	(281)	(220)	0	(14)	0	0	(220)
Own Load After EE/DE	6,200	6,191	5,819	6,316	7,320	8,688	9,477	9,654	8,710	6,937	5,453	6,064	9,654

PEAK DEMAND (MW)

YEAR: 2035	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Residential	3,191	3,139	2,891	3,425	4,333	5,844	6,359	6,367	5,283	3,618	2,396	3,141	6,367
Comm+Ind <3 MW	2,347	2,361	2,322	2,458	2,668	3,259	3,634	3,614	3,570	3,219	2,494	2,309	3,614
Comm+Ind >3 MW	563	611	617	605	589	677	649	656	644	653	600	504	656
Irrigation	1	1	2	2	2	3	3	2	2	2	1	1	2
Streetlights	28	11	19	1	1	0	0	0	0	1	1	10	0
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
System Peak Pr or to Losses	6,129	6,122	5,850	6,491	7,593	9,783	10,645	10,639	9,499	7,493	5,492	5,965	10,639
Losses On Peak	412	411	386	420	487	574	622	632	564	461	366	403	632
Total Own Load Peak	6,542	6,534	6,236	6,910	8,080	10,357	11,267	11,271	10,063	7,955	5,858	6,368	11,271
Energy Efficiency Programs	(198)	(150)	(294)	(456)	(586)	(1,406)	(1,219)	(1,474)	(1,087)	(850)	(225)	(174)	(1,474)
Distributed Energy Programs	0	(53)	0	0	0	(121)	(486)	(73)	(295)	(8)	0	0	(73)
Own Load After EE/DE	6,343	6,330	5,942	6,454	7,493	8,830	9,562	9,724	8,681	7,097	5,633	6,194	9,724

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS

ENERGY DEMAND (MWH)													
YEAR: 2020	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Residential	959,532	805,287	771,917	792,171	965,617	1,513,753	1,966,134	1,840,764	1,528,652	1,029,467	747,690	942,518	13,863,503
Comm+Ind <3 MW	852,208	793,562	920,320	897,554	1,047,763	1,125,315	1,071,621	1,192,610	1,045,637	933,747	871,741	876,193	11,628,271
Comm+Ind >3 MW	254,542	251,334	251,013	256,421	264,806	281,730	293,694	300,298	304,164	286,283	272,829	262,435	3,279,550
Irrigation	716	361	619	1,143	1,335	1,369	1,195	899	1,291	585	538	405	10,456
Streetlights	8,936	9,736	11,385	10,965	11,459	9,854	10,205	9,123	9,412	10,708	10,876	10,072	122,731
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,075,934	1,860,280	1,955,254	1,958,254	2,290,981	2,932,021	3,342,849	3,343,694	2,889,156	2,260,790	1,903,674	2,091,623	28,904,510
Energy Eff ciency Programs	(8,338)	(7,552)	(9,732)	(13,918)	(18,223)	(28,580)	(35,298)	(32,064)	(24,119)	(15,914)	(9,023)	(7,884)	(210,644)
Distributed Energy Programs	(11,241)	(13,704)	(17,834)	(18,772)	(20,915)	(20,560)	(18,672)	(17,526)	(16,117)	(14,843)	(11,586)	(9,844)	(191,614)
Total Sales	2,056,355	1,839,024	1,927,688	1,925,564	2,251,844	2,882,881	3,288,879	3,294,104	2,848,920	2,230,034	1,883,065	2,073,896	28,502,252
Energy Losses	143,659	121,066	131,469	129,932	157,452	199,440	215,634	222,306	187,692	157,289	136,148	155,686	1,957,775
Total Own Load Energy	2,200,014	1,960,090	2,059,157	2,055,496	2,409,296	3,082,321	3,504,513	3,516,410	3,036,612	2,387,323	2,019,213	2,229,582	30,460,027

ENERGY DEMAND (MWH)													
YEAR: 2021	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Residential	1,029,849	815,709	810,504	814,448	989,574	1,553,485	2,024,409	1,895,557	1,584,990	1,061,615	772,756	971,148	14,324,043
Comm+Ind <3 MW	778,372	797,562	966,613	921,525	1,074,159	1,153,900	1,099,689	1,224,859	1,080,067	958,849	895,166	899,786	11,850,547
Comm+Ind >3 MW	279,174	276,483	282,054	289,049	301,376	320,564	336,508	346,440	351,731	338,559	327,325	322,320	3,771,584
Irrigation	708	353	629	1,143	1,334	1,369	1,193	899	1,295	583	538	404	10,448
Streetlights	10,326	9,738	11,724	11,139	11,666	10,012	10,353	9,283	9,593	10,865	11,032	10,234	125,965
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,098,429	1,899,845	2,071,525	2,037,304	2,378,109	3,039,331	3,472,152	3,477,038	3,027,677	2,370,471	2,006,816	2,203,891	30,082,587
Energy Eff ciency Programs	(15,371)	(13,330)	(17,892)	(25,508)	(33,397)	(52,378)	(64,484)	(59,013)	(44,202)	(29,125)	(16,546)	(14,396)	(385,641)
Distributed Energy Programs	(19,581)	(22,982)	(31,066)	(32,700)	(36,433)	(35,815)	(32,526)	(30,530)	(28,075)	(25,857)	(20,183)	(17,148)	(332,896)
Total Sales	2,063,477	1,863,533	2,022,566	1,979,096	2,308,279	2,951,137	3,375,142	3,387,494	2,955,399	2,315,490	1,970,087	2,172,347	29,364,049
Energy Losses	140,277	121,104	142,556	135,888	165,759	205,583	210,067	218,308	174,773	144,235	119,476	138,727	1,916,751
Total Own Load Energy	2,203,754	1,984,637	2,165,122	2,114,984	2,474,038	3,156,720	3,585,209	3,605,802	3,130,172	2,459,725	2,089,563	2,311,074	31,280,800

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2022	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,065,967	840,284	833,150	839,090	1,018,675	1,594,555	2,082,775	1,950,367	1,640,864	1,092,433	801,151	1,000,078	14,759,388
Comm+Ind <3 MW	806,976	821,615	995,238	951,384	1,109,642	1,185,537	1,131,154	1,261,242	1,118,293	985,648	925,556	926,025	12,218,309
Comm+Ind >3 MW	315,666	309,474	318,695	324,527	337,881	356,033	373,060	383,124	387,005	375,135	362,767	358,718	4,202,084
Irrigation	710	353	629	1,145	1,339	1,365	1,190	899	1,296	581	539	404	10,450
Streetlights	10,505	9,874	11,900	11,320	11,904	10,141	10,477	9,426	9,757	10,996	11,209	10,381	127,890
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,199,823	1,981,600	2,159,613	2,127,465	2,479,441	3,147,631	3,598,656	3,605,058	3,157,215	2,464,792	2,101,222	2,295,606	31,318,121
Energy Eff ciency Programs	(22,288)	(19,386)	(26,022)	(37,022)	(48,661)	(76,177)	(93,184)	(86,187)	(64,286)	(42,357)	(24,064)	(21,011)	(560,644)
Distributed Energy Programs	(25,292)	(29,684)	(40,126)	(42,236)	(47,058)	(46,259)	(42,012)	(39,433)	(36,263)	(33,397)	(26,069)	(22,148)	(429,976)
Total Sales	2,152,243	1,932,530	2,093,465	2,048,208	2,383,723	3,025,195	3,463,460	3,479,438	3,056,666	2,389,038	2,051,089	2,252,446	30,327,501
Energy Losses	143,987	125,381	151,062	143,460	177,221	216,454	212,088	223,928	174,190	145,945	121,354	143,017	1,978,087
Total Own Load Energy	2,296,230	2,057,911	2,244,527	2,191,668	2,560,944	3,241,649	3,675,548	3,703,366	3,230,856	2,534,983	2,172,443	2,395,463	32,305,588

ENERGY DEMAND (MWH)													
YEAR: 2023	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,098,257	866,306	856,893	861,866	1,047,805	1,635,515	2,146,866	2,012,159	1,688,434	1,124,091	831,164	1,029,671	15,199,028
Comm+Ind <3 MW	828,131	844,606	1,021,978	975,322	1,141,780	1,214,406	1,165,211	1,299,672	1,146,771	1,010,307	955,100	950,199	12,553,483
Comm+Ind >3 MW	352,185	342,482	355,318	360,003	374,359	391,570	409,647	419,793	422,237	411,382	398,194	395,185	4,632,355
Irrigation	709	354	630	1,143	1,342	1,364	1,190	901	1,294	579	541	403	10,450
Streetlights	10,641	10,013	12,072	11,454	12,126	10,263	10,631	9,589	9,865	11,117	11,387	10,518	129,676
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,289,923	2,063,761	2,246,891	2,209,787	2,577,412	3,253,118	3,733,546	3,742,115	3,268,600	2,557,476	2,196,386	2,385,976	32,524,992
Energy Eff ciency Programs	(29,162)	(25,438)	(34,147)	(48,482)	(63,973)	(99,962)	(122,279)	(113,098)	(84,100)	(55,662)	(31,577)	(27,765)	(735,644)
Distributed Energy Programs	(32,360)	(37,979)	(51,340)	(54,039)	(60,209)	(59,188)	(53,753)	(50,453)	(46,397)	(42,731)	(33,354)	(28,338)	(550,141)
Total Sales	2,228,402	2,000,343	2,161,404	2,107,266	2,453,231	3,093,968	3,557,514	3,578,563	3,138,104	2,459,084	2,131,455	2,329,873	31,239,207
Energy Losses	148,733	129,717	159,931	150,243	188,980	226,779	214,599	230,126	171,339	147,507	123,135	147,075	2,038,164
Total Own Load Energy	2,377,135	2,130,060	2,321,335	2,257,509	2,642,211	3,320,747	3,772,113	3,808,689	3,309,443	2,606,591	2,254,590	2,476,948	33,277,371

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2024	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,132,255	908,909	862,141	888,386	1,073,041	1,674,009	2,210,421	2,068,576	1,741,545	1,167,122	855,558	1,060,818	15,642,781
Comm+Ind <3 MW	854,044	889,777	1,025,721	1,005,923	1,168,828	1,242,104	1,202,831	1,335,098	1,181,347	1,046,772	979,496	977,219	12,909,160
Comm+Ind >3 MW	388,726	379,916	392,063	395,547	410,829	427,130	446,313	456,387	457,691	447,540	433,666	431,667	5,067,475
Irrigation	710	362	620	1,147	1,340	1,358	1,193	901	1,293	584	539	403	10,450
Streetlights	10,779	10,343	11,995	11,630	12,272	10,353	10,787	9,711	9,990	11,306	11,496	10,655	131,317
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,386,514	2,189,307	2,292,540	2,302,634	2,666,310	3,354,954	3,871,546	3,870,672	3,391,866	2,673,324	2,280,755	2,480,762	33,761,183
Energy Eff ciency Programs	(36,096)	(32,579)	(42,002)	(60,257)	(79,186)	(122,385)	(152,329)	(139,405)	(104,100)	(68,998)	(39,061)	(34,249)	(910,646)
Distributed Energy Programs	(40,346)	(49,431)	(64,010)	(67,376)	(75,067)	(73,794)	(67,018)	(62,905)	(57,847)	(53,276)	(41,586)	(35,332)	(687,988)
Total Sales	2,310,072	2,107,297	2,186,528	2,175,001	2,512,057	3,158,775	3,652,199	3,668,362	3,229,919	2,551,050	2,200,108	2,411,182	32,162,549
Energy Losses	153,620	139,775	162,804	158,583	199,459	235,227	218,675	234,289	169,945	151,385	123,492	151,228	2,098,483
Total Own Load Energy	2,463,692	2,247,072	2,349,332	2,333,584	2,711,516	3,394,002	3,870,874	3,902,651	3,399,864	2,702,435	2,323,600	2,562,410	34,261,032

ENERGY DEMAND (MWH)													
YEAR: 2025	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,168,602	921,073	899,996	914,867	1,100,514	1,721,933	2,276,190	2,124,697	1,791,405	1,204,905	886,278	1,094,428	16,104,886
Comm+Ind <3 MW	879,014	893,766	1,068,843	1,033,477	1,196,142	1,277,982	1,236,157	1,367,773	1,211,065	1,075,606	1,008,378	1,004,551	13,252,757
Comm+Ind >3 MW	425,252	408,539	428,521	431,046	447,302	462,418	482,946	493,127	492,938	483,874	469,080	468,034	5,493,076
Irrigation	711	354	627	1,149	1,339	1,362	1,192	898	1,291	585	539	404	10,451
Streetlights	10,916	10,267	12,301	11,773	12,416	10,506	10,901	9,804	10,077	11,431	11,638	10,790	132,820
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,484,496	2,233,998	2,410,287	2,392,313	2,757,713	3,474,201	4,007,386	3,996,300	3,506,776	2,776,401	2,375,913	2,578,207	34,993,990
Energy Eff ciency Programs	(43,078)	(37,582)	(50,116)	(71,915)	(94,333)	(146,867)	(181,777)	(165,665)	(124,625)	(82,359)	(46,576)	(40,750)	(1,085,643)
Distributed Energy Programs	(49,405)	(57,985)	(78,383)	(82,505)	(91,924)	(90,365)	(82,067)	(77,030)	(70,837)	(65,239)	(50,924)	(43,265)	(839,928)
Total Sales	2,392,013	2,138,431	2,281,788	2,237,892	2,571,456	3,236,970	3,743,542	3,753,605	3,311,313	2,628,803	2,278,413	2,494,191	33,068,418
Energy Losses	158,872	138,867	176,867	166,420	210,518	247,579	219,738	238,070	167,274	153,561	124,841	155,477	2,158,083
Total Own Load Energy	2,550,885	2,277,298	2,458,655	2,404,312	2,781,974	3,484,549	3,963,280	3,991,675	3,478,587	2,782,364	2,403,254	2,649,668	35,226,501

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2026	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,199,358	950,158	928,548	937,414	1,129,770	1,771,802	2,342,891	2,186,495	1,845,272	1,243,989	917,691	1,130,038	16,583,428
Comm+Ind <3 MW	898,123	917,947	1,099,227	1,053,970	1,225,437	1,317,651	1,271,347	1,404,913	1,243,724	1,105,463	1,037,643	1,033,722	13,609,167
Comm+Ind >3 MW	461,681	441,603	465,208	466,546	483,755	497,953	519,548	529,788	528,142	520,085	504,508	504,463	5,923,281
Irrigation	708	355	628	1,144	1,338	1,368	1,192	898	1,289	586	541	404	10,451
Streetlights	10,980	10,381	12,468	11,834	12,571	10,685	11,020	9,923	10,173	11,553	11,771	10,933	134,292
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,570,850	2,320,445	2,506,079	2,470,909	2,852,871	3,599,459	4,145,998	4,132,018	3,628,600	2,881,676	2,472,154	2,679,559	36,260,618
Energy Eff ciency Programs	(50,095)	(43,588)	(58,310)	(83,400)	(109,197)	(171,252)	(211,475)	(192,118)	(144,531)	(95,369)	(54,055)	(47,254)	(1,260,644)
Distributed Energy Programs	(58,812)	(69,025)	(93,307)	(98,213)	(109,426)	(107,570)	(97,692)	(91,696)	(84,324)	(77,660)	(60,620)	(51,503)	(999,847)
Total Sales	2,461,943	2,207,832	2,354,463	2,289,295	2,634,248	3,320,637	3,836,831	3,848,203	3,399,746	2,708,647	2,357,479	2,580,802	34,000,127
Energy Losses	162,303	143,369	187,179	172,138	221,696	261,025	221,092	242,934	164,701	156,016	126,374	160,049	2,218,875
Total Own Load Energy	2,624,246	2,351,201	2,541,642	2,461,433	2,855,944	3,581,662	4,057,923	4,091,137	3,564,447	2,864,663	2,483,853	2,740,851	36,219,002

ENERGY DEMAND (MWH)													
YEAR: 2027	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,234,325	978,634	956,945	965,537	1,160,088	1,818,512	2,408,599	2,248,183	1,908,618	1,282,394	948,106	1,164,853	17,074,794
Comm+Ind <3 MW	920,733	940,808	1,128,552	1,081,559	1,255,043	1,350,828	1,305,125	1,441,904	1,283,354	1,134,160	1,064,448	1,060,759	13,967,273
Comm+Ind >3 MW	498,105	474,669	501,918	502,045	520,584	533,377	555,960	566,388	563,490	556,196	539,980	540,888	6,353,599
Irrigation	707	354	629	1,144	1,338	1,367	1,190	899	1,292	585	539	404	10,448
Streetlights	11,074	10,474	12,619	11,959	12,715	10,802	11,119	10,039	10,312	11,662	11,878	11,048	135,701
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,664,944	2,404,939	2,600,663	2,562,244	2,949,768	3,714,885	4,281,993	4,267,413	3,767,066	2,984,996	2,564,952	2,777,952	37,541,815
Energy Eff ciency Programs	(57,196)	(49,638)	(66,606)	(94,965)	(124,332)	(194,992)	(240,027)	(219,678)	(164,567)	(108,431)	(61,593)	(53,619)	(1,435,645)
Distributed Energy Programs	(68,705)	(80,636)	(109,002)	(114,734)	(127,832)	(125,664)	(114,125)	(107,120)	(98,508)	(90,723)	(70,816)	(60,166)	(1,168,030)
Total Sales	2,539,043	2,274,665	2,425,056	2,352,545	2,697,603	3,394,230	3,927,841	3,940,615	3,503,991	2,785,841	2,432,542	2,664,167	34,938,139
Energy Losses	166,505	147,530	197,471	179,605	233,305	271,852	221,418	248,897	163,623	157,978	127,294	164,077	2,279,555
Total Own Load Energy	2,705,548	2,422,195	2,622,527	2,532,150	2,930,908	3,666,082	4,149,259	4,189,512	3,667,614	2,943,819	2,559,836	2,828,244	37,217,694

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2028	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,275,945	1,024,046	970,100	995,182	1,196,676	1,865,741	2,478,640	2,315,333	1,968,050	1,315,868	985,234	1,199,466	17,590,279
Comm+Ind <3 MW	949,912	985,117	1,137,188	1,110,179	1,293,789	1,380,523	1,339,612	1,482,819	1,318,871	1,157,826	1,098,439	1,086,484	14,340,757
Comm+Ind >3 MW	534,599	516,681	538,494	537,423	556,885	569,024	592,506	603,140	598,581	593,153	575,386	577,338	6,793,211
Irrigation	709	362	622	1,144	1,345	1,363	1,188	900	1,292	580	543	402	10,450
Streetlights	11,219	10,771	12,559	12,085	12,937	10,866	11,215	10,170	10,415	11,728	12,039	11,144	137,148
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,772,384	2,536,977	2,658,963	2,656,013	3,061,632	3,827,517	4,423,160	4,412,361	3,897,209	3,079,155	2,671,641	2,874,833	38,871,846
Energy Eff ciency Programs	(63,938)	(57,562)	(74,656)	(106,004)	(139,904)	(218,558)	(267,348)	(247,283)	(183,900)	(121,731)	(69,036)	(60,723)	(1,610,644)
Distributed Energy Programs	(78,889)	(96,060)	(125,159)	(131,741)	(146,781)	(144,291)	(131,042)	(122,999)	(113,110)	(104,171)	(81,314)	(69,085)	(1,344,642)
Total Sales	2,629,557	2,383,355	2,459,147	2,418,268	2,774,947	3,464,668	4,024,770	4,042,080	3,600,198	2,853,252	2,521,292	2,745,026	35,916,559
Energy Losses	171,922	159,987	199,947	187,195	248,636	281,090	221,264	256,881	160,423	158,717	129,767	168,130	2,343,960
Total Own Load Energy	2,801,479	2,543,342	2,659,094	2,605,463	3,023,583	3,745,758	4,246,034	4,298,961	3,760,621	3,011,969	2,651,059	2,913,156	38,260,519

ENERGY DEMAND (MWH)													
YEAR: 2029	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,316,236	1,041,318	1,012,244	1,024,050	1,227,333	1,914,137	2,552,558	2,382,171	2,026,398	1,362,849	1,018,225	1,236,614	18,114,131
Comm+Ind <3 MW	976,265	991,484	1,183,285	1,137,132	1,321,991	1,413,580	1,379,982	1,521,886	1,352,559	1,193,315	1,127,000	1,114,182	14,712,660
Comm+Ind >3 MW	571,296	540,663	575,299	573,070	593,374	604,636	629,181	639,722	634,241	629,047	610,860	613,530	7,214,918
Irrigation	710	354	629	1,143	1,342	1,362	1,192	900	1,290	584	542	402	10,450
Streetlights	11,339	10,694	12,861	12,193	13,055	10,970	11,360	10,284	10,503	11,878	12,150	11,256	138,543
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,875,846	2,584,513	2,784,318	2,747,588	3,157,095	3,944,684	4,574,273	4,554,963	4,024,991	3,197,674	2,768,777	2,975,984	40,190,703
Energy Eff ciency Programs	(70,813)	(61,790)	(82,649)	(117,979)	(155,373)	(241,407)	(297,873)	(274,638)	(203,607)	(135,391)	(76,688)	(67,436)	(1,785,642)
Distributed Energy Programs	(89,831)	(105,431)	(142,520)	(150,014)	(167,141)	(164,306)	(149,218)	(140,060)	(128,799)	(118,621)	(92,592)	(78,667)	(1,527,200)
Total Sales	2,715,201	2,417,292	2,559,149	2,479,594	2,834,581	3,538,972	4,127,181	4,140,265	3,692,585	2,943,662	2,599,496	2,829,881	36,877,860
Energy Losses	176,674	157,275	217,140	194,832	259,918	290,438	225,280	262,258	156,989	163,092	130,576	172,204	2,406,675
Total Own Load Energy	2,891,875	2,574,567	2,776,289	2,674,426	3,094,499	3,829,410	4,352,461	4,402,523	3,849,574	3,106,754	2,730,072	3,002,085	39,284,535

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2030	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,360,169	1,074,076	1,038,645	1,058,035	1,261,712	1,964,441	2,623,962	2,447,893	2,090,915	1,409,220	1,051,216	1,276,752	18,657,037
Comm+Ind <3 MW	1,004,805	1,017,062	1,207,075	1,170,292	1,353,801	1,444,386	1,415,079	1,558,180	1,390,754	1,226,802	1,153,925	1,143,918	15,086,079
Comm+Ind >3 MW	607,827	573,685	612,047	608,544	629,809	640,175	665,878	676,297	669,384	665,036	645,809	649,590	7,644,081
Irrigation	712	353	627	1,147	1,344	1,358	1,190	899	1,291	586	541	402	10,450
Streetlights	11,476	10,798	12,943	12,355	13,201	11,043	11,458	10,376	10,619	12,010	12,245	11,381	139,905
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	2,984,989	2,675,975	2,871,337	2,850,373	3,259,868	4,061,403	4,717,567	4,693,645	4,162,963	3,313,654	2,863,736	3,082,043	41,537,551
Energy Eff ciency Programs	(77,792)	(67,892)	(90,521)	(129,899)	(170,713)	(263,802)	(328,327)	(300,491)	(224,409)	(148,751)	(84,201)	(73,843)	(1,960,641)
Distributed Energy Programs	(101,023)	(118,566)	(160,276)	(168,704)	(187,964)	(184,776)	(167,809)	(157,509)	(144,846)	(133,399)	(104,128)	(88,468)	(1,717,468)
Total Sales	2,806,173	2,489,516	2,620,540	2,551,770	2,901,191	3,612,825	4,221,432	4,235,645	3,793,708	3,031,503	2,675,406	2,919,732	37,859,442
Energy Losses	182,118	162,251	226,048	204,704	272,752	298,871	227,395	265,693	156,615	166,263	130,992	176,743	2,470,444
Total Own Load Energy	2,988,291	2,651,767	2,846,588	2,756,474	3,173,943	3,911,696	4,448,827	4,501,338	3,950,323	3,197,766	2,806,398	3,096,475	40,329,886

ENERGY DEMAND (MWH)													
YEAR: 2031	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,402,096	1,109,009	1,070,696	1,091,744	1,296,857	2,021,913	2,702,972	2,515,598	2,150,573	1,455,661	1,089,650	1,318,520	19,225,290
Comm+Ind <3 MW	1,029,727	1,043,382	1,236,946	1,200,968	1,384,652	1,483,979	1,452,041	1,594,685	1,423,580	1,258,836	1,185,950	1,173,966	15,468,714
Comm+Ind >3 MW	643,428	605,648	646,967	642,622	664,613	673,432	700,544	710,939	700,557	695,345	673,391	675,920	8,033,406
Irrigation	711	354	627	1,149	1,343	1,362	1,189	897	1,288	586	542	403	10,451
Streetlights	11,571	10,905	13,075	12,485	13,332	11,183	11,560	10,456	10,695	12,123	12,374	11,503	141,262
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	3,087,532	2,769,299	2,968,311	2,948,968	3,360,797	4,191,869	4,868,307	4,832,575	4,286,694	3,422,552	2,961,907	3,180,312	42,879,123
Energy Eff ciency Programs	(84,740)	(73,938)	(98,577)	(141,468)	(185,561)	(288,925)	(357,555)	(325,867)	(245,182)	(162,035)	(91,605)	(80,193)	(2,135,645)
Distributed Energy Programs	(112,093)	(131,559)	(177,839)	(187,191)	(208,561)	(205,024)	(186,198)	(174,769)	(160,718)	(148,017)	(115,539)	(98,162)	(1,905,669)
Total Sales	2,890,699	2,563,802	2,691,895	2,620,310	2,966,676	3,697,920	4,324,554	4,331,939	3,880,794	3,112,499	2,754,764	3,001,957	38,837,809
Energy Losses	186,502	167,326	236,591	213,420	284,745	313,090	227,551	269,194	153,899	168,620	132,459	180,779	2,534,176
Total Own Load Energy	3,077,201	2,731,128	2,928,486	2,833,730	3,251,421	4,011,010	4,552,105	4,601,133	4,034,693	3,281,119	2,887,223	3,182,736	41,371,985

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2032	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,440,633	1,158,235	1,092,245	1,121,597	1,332,780	2,079,840	2,779,243	2,586,889	2,220,274	1,501,280	1,126,274	1,361,306	19,800,597
Comm+Ind <3 MW	1,050,620	1,088,845	1,251,102	1,223,958	1,415,822	1,526,288	1,488,463	1,634,779	1,463,933	1,289,966	1,215,400	1,204,868	15,854,044
Comm+Ind >3 MW	667,835	639,570	667,976	660,845	681,883	687,901	713,173	721,818	711,015	705,639	683,878	686,602	8,228,135
Irrigation	708	362	622	1,144	1,340	1,367	1,188	898	1,289	586	542	404	10,450
Streetlights	11,622	11,191	13,045	12,536	13,458	11,347	11,653	10,564	10,812	12,222	12,477	11,623	142,550
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	3,171,418	2,898,202	3,024,990	3,020,080	3,445,284	4,306,744	4,993,721	4,954,948	4,407,322	3,509,693	3,038,571	3,264,803	44,035,776
Energy Eff ciency Programs	(91,672)	(82,852)	(107,078)	(152,660)	(199,859)	(313,468)	(385,805)	(353,139)	(264,563)	(174,309)	(99,023)	(86,217)	(2,310,645)
Distributed Energy Programs	(123,034)	(150,108)	(195,197)	(205,461)	(228,917)	(225,035)	(204,371)	(191,828)	(176,405)	(162,464)	(126,816)	(107,743)	(2,097,379)
Total Sales	2,956,711	2,665,243	2,722,715	2,661,959	3,016,508	3,768,241	4,403,545	4,409,981	3,966,354	3,172,920	2,812,732	3,070,843	39,627,752
Energy Losses	188,971	181,904	237,372	217,477	294,922	326,978	225,628	274,350	151,248	169,423	132,659	183,884	2,584,816
Total Own Load Energy	3,145,682	2,847,147	2,960,087	2,879,436	3,311,430	4,095,219	4,629,173	4,684,331	4,117,602	3,342,343	2,945,391	3,254,727	42,212,568

ENERGY DEMAND (MWH)													
YEAR: 2033	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,486,635	1,178,837	1,140,728	1,157,644	1,372,906	2,136,425	2,857,328	2,657,110	2,292,828	1,544,955	1,166,827	1,403,824	20,396,046
Comm+Ind <3 MW	1,079,261	1,093,919	1,302,452	1,256,232	1,453,657	1,560,678	1,523,502	1,673,829	1,505,865	1,318,908	1,248,760	1,234,497	16,251,560
Comm+Ind >3 MW	678,377	635,593	678,524	670,891	692,114	697,951	723,342	732,216	720,797	717,284	693,802	696,664	8,337,555
Irrigation	708	354	629	1,146	1,345	1,365	1,184	897	1,292	584	542	404	10,450
Streetlights	11,736	11,081	13,365	12,666	13,633	11,424	11,724	10,657	10,931	12,301	12,603	11,725	143,846
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	3,256,716	2,919,784	3,135,698	3,098,578	3,533,656	4,407,843	5,117,080	5,074,709	4,531,713	3,594,031	3,122,534	3,347,114	45,139,456
Energy Eff ciency Programs	(98,783)	(85,986)	(115,345)	(164,131)	(215,801)	(337,707)	(413,049)	(382,091)	(285,064)	(187,834)	(106,668)	(93,185)	(2,485,643)
Distributed Energy Programs	(134,592)	(157,964)	(213,533)	(224,762)	(250,422)	(246,174)	(223,570)	(209,848)	(192,976)	(177,726)	(138,729)	(117,865)	(2,288,159)
Total Sales	3,023,342	2,675,834	2,806,820	2,709,685	3,067,433	3,823,962	4,480,462	4,482,770	4,053,673	3,228,471	2,877,137	3,136,064	40,365,654
Energy Losses	193,227	174,300	257,226	224,795	309,022	335,715	221,915	280,080	148,306	169,212	133,258	186,794	2,633,849
Total Own Load Energy	3,216,569	2,850,134	3,064,046	2,934,480	3,376,455	4,159,677	4,702,377	4,762,850	4,201,979	3,397,683	3,010,395	3,322,858	42,999,503

ATTACHMENT C.1(B): ENERGY CONSUMPTION BY MONTH AND CUSTOMER CLASS (CONTINUED)

ENERGY DEMAND (MWH)													
YEAR: 2034	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,532,816	1,216,529	1,176,166	1,192,694	1,414,257	2,194,208	2,941,902	2,737,695	2,357,450	1,590,081	1,209,745	1,446,764	21,010,307
Comm+Ind <3 MW	1,106,065	1,121,458	1,334,353	1,285,227	1,491,812	1,595,880	1,564,539	1,719,551	1,540,432	1,348,686	1,284,114	1,263,596	16,655,713
Comm+Ind >3 MW	688,731	644,834	688,699	680,777	702,177	708,148	733,671	742,483	730,487	726,937	703,673	707,030	8,457,649
Irrigation	708	354	630	1,144	1,349	1,362	1,185	899	1,289	583	544	403	10,450
Streetlights	11,828	11,179	13,491	12,758	13,804	11,504	11,835	10,781	10,997	12,381	12,738	11,818	145,114
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	3,340,148	2,994,354	3,213,339	3,172,600	3,623,399	4,511,102	5,253,132	5,211,410	4,640,656	3,678,668	3,210,815	3,429,611	46,279,233
Energy Eff ciency Programs	(105,471)	(92,045)	(123,479)	(175,322)	(231,444)	(361,487)	(442,184)	(409,004)	(304,187)	(201,389)	(114,184)	(100,449)	(2,660,645)
Distributed Energy Programs	(145,841)	(171,167)	(231,380)	(243,548)	(271,352)	(266,750)	(242,256)	(227,387)	(209,105)	(192,581)	(150,324)	(127,716)	(2,479,404)
Total Sales	3,088,836	2,731,143	2,858,479	2,753,731	3,120,603	3,882,865	4,568,692	4,575,019	4,127,364	3,284,698	2,946,307	3,201,447	41,139,183
Energy Losses	195,758	178,203	266,767	230,562	322,997	344,298	222,615	286,756	142,215	169,737	134,471	189,759	2,684,139
Total Own Load Energy	3,284,594	2,909,346	3,125,246	2,984,293	3,443,600	4,227,163	4,791,307	4,861,775	4,269,579	3,454,435	3,080,778	3,391,206	43,823,322

ENERGY DEMAND (MWH)													
YEAR: 2035	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Residential	1,582,553	1,255,954	1,209,979	1,228,796	1,453,323	2,253,676	3,027,859	2,816,906	2,426,378	1,645,660	1,250,070	1,492,242	21,643,397
Comm+Ind <3 MW	1,135,898	1,150,508	1,363,042	1,315,301	1,523,704	1,632,885	1,608,655	1,762,841	1,577,651	1,387,727	1,315,871	1,294,531	17,068,614
Comm+Ind >3 MW	699,092	654,262	699,191	690,939	712,375	718,250	744,051	752,634	740,879	736,510	713,643	716,922	8,578,749
Irrigation	709	354	629	1,144	1,346	1,361	1,188	900	1,287	585	545	402	10,450
Streetlights	11,940	11,283	13,580	12,853	13,910	11,595	11,969	10,885	11,072	12,520	12,840	11,918	146,365
Resale (x/off-system sales)	0	0	0	0	0	0	0	0	0	0	0	0	0
Sales Prior to EE/ DE	3,430,193	3,072,361	3,286,421	3,249,033	3,704,659	4,617,767	5,393,723	5,344,166	4,757,268	3,783,002	3,292,970	3,516,014	47,447,575
Energy Eff ciency Programs	(112,458)	(98,143)	(131,218)	(187,369)	(246,756)	(383,315)	(473,010)	(436,109)	(323,328)	(215,044)	(121,790)	(107,103)	(2,835,643)
Distributed Energy Programs	(157,077)	(184,353)	(249,206)	(262,310)	(292,257)	(287,300)	(260,919)	(244,905)	(225,214)	(207,417)	(161,904)	(137,555)	(2,670,417)
Total Sales	3,160,658	2,789,864	2,905,997	2,799,354	3,165,646	3,947,151	4,659,793	4,663,153	4,208,726	3,360,541	3,009,276	3,271,356	41,941,515
Energy Losses	199,303	182,469	274,904	237,290	332,936	351,984	227,286	291,209	137,511	174,089	134,229	192,795	2,736,005
Total Own Load Energy	3,359,961	2,972,333	3,180,901	3,036,644	3,498,582	4,299,135	4,887,079	4,954,362	4,346,237	3,534,630	3,143,505	3,464,151	44,677,520

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM

PEAK DEMAND (MW)

YEAR: 2020	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak (BAU+EV+DATA)	4,251	4,085	3,785	4,412	5,193	6,811	7,410	7,413	6,604	5,131	3,661	4,062	7,410
Energy Efficiency Programs	(23)	(18)	(31)	(45)	(79)	(116)	(124)	(120)	(82)	(63)	(26)	(20)	(124)
Own Load Peak After EE Before DE	4,227	4,067	3,755	4,367	5,114	6,694	7,286	7,293	6,523	5,068	3,635	4,042	7,286
Distributed Energy Programs	0	(4)	0	(2)	(26)	(31)	(7)	(29)	(13)	(10)	0	0	(7)
Own Load Peak - After DE/EE	4,227	4,063	3,755	4,365	5,088	6,663	7,278	7,264	6,510	5,057	3,635	4,042	7,278

PEAK DEMAND (MW)

YEAR: 2021	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	4,272	4,297	4,004	4,568	5,369	7,032	7,646	7,650	6,848	5,339	3,800	4,215	7,650
Energy Efficiency Programs	(43)	(33)	(35)	(105)	(146)	(213)	(227)	(220)	(197)	(115)	(25)	(37)	(220)
Own Load Peak After EE Before DE	4,229	4,265	3,969	4,463	5,223	6,818	7,418	7,431	6,651	5,223	3,775	4,178	7,431
Distributed Energy Programs	0	(7)	0	(22)	(45)	(53)	(54)	(51)	(52)	(18)	(5)	0	(51)
Own Load Peak - After DE/EE	4,229	4,258	3,969	4,442	5,179	6,765	7,365	7,379	6,600	5,205	3,770	4,178	7,379

PEAK DEMAND (MW)

YEAR: 2022	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	4,448	4,456	4,162	4,746	5,578	7,263	7,888	7,893	7,097	5,512	3,957	4,369	7,893
Energy Efficiency Programs	(62)	(47)	(65)	(152)	(212)	(310)	(304)	(320)	(263)	(168)	(69)	(54)	(320)
Own Load Peak After EE Before DE	4,386	4,408	4,097	4,594	5,366	6,952	7,583	7,573	6,834	5,344	3,887	4,315	7,573
Distributed Energy Programs	0	(9)	0	(28)	(36)	(72)	(95)	(66)	(46)	(23)	0	0	(66)
													0
Own Load Peak - After DE/EE	4,386	4,400	4,097	4,566	5,330	6,881	7,488	7,506	6,788	5,321	3,887	4,315	7,506

PEAK DEMAND (MW)

YEAR: 2023	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	4,605	4,614	4,320	4,905	5,779	7,486	8,135	8,140	7,301	5,681	4,113	4,520	8,140
Energy Efficiency Programs	(82)	(62)	(67)	(200)	(271)	(407)	(434)	(353)	(345)	(220)	(91)	(70)	(353)
Own Load Peak After EE Before DE	4,523	4,552	4,253	4,706	5,509	7,078	7,701	7,787	6,956	5,461	4,022	4,449	7,787
Distributed Energy Programs	0	(11)	0	(31)	0	(88)	(21)	(82)	(36)	(30)	0	0	(82)
													0
Own Load Peak - After DE/EE	4,523	4,541	4,253	4,675	5,509	6,990	7,680	7,705	6,920	5,432	4,022	4,449	7,705

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)

YEAR: 2024	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	4,773	4,706	4,391	5,089	5,958	7,695	8,387	8,390	7,533	5,904	4,248	4,677	8,390
Energy Efficiency Programs	(101)	(77)	(133)	(247)	(277)	(504)	(470)	(413)	(427)	(272)	(113)	(87)	(413)
Own Load Peak After EE Before DE	4,672	4,629	4,258	4,842	5,681	7,191	7,917	7,978	7,106	5,632	4,135	4,590	7,978
Distributed Energy Programs	0	(14)	0	(36)	0	(95)	(97)	(102)	(45)	(37)	0	0	(102)
													0
Own Load Peak - After DE/EE	4,672	4,616	4,258	4,806	5,681	7,096	7,820	7,876	7,061	5,595	4,135	4,590	7,876

PEAK DEMAND (MW)

YEAR: 2025	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	4,943	4,942	4,613	5,262	6,141	7,950	8,641	8,647	7,744	6,095	4,402	4,838	8,641
Energy Efficiency Programs	(100)	(78)	(111)	(272)	(364)	(600)	(637)	(615)	(523)	(331)	(78)	(90)	(637)
Own Load Peak After EE Before DE	4,842	4,864	4,501	4,990	5,778	7,351	8,004	8,032	7,221	5,764	4,324	4,748	8,004
Distributed Energy Programs	0	(17)	0	(31)	0	(110)	(33)	(124)	(100)	(45)	(13)	0	(33)
													0
Own Load Peak - After DE/EE	4,842	4,847	4,501	4,959	5,778	7,241	7,971	7,907	7,121	5,718	4,311	4,748	7,971

PEAK DEMAND (MW)

YEAR: 2026	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	5,085	5,106	4,787	5,407	6,332	8,218	8,898	8,904	7,963	6,252	4,556	5,005	8,898
Energy Efficiency Programs	(116)	(91)	(114)	(227)	(387)	(695)	(667)	(713)	(455)	(384)	(162)	(104)	(667)
Own Load Peak After EE Before DE	4,969	5,015	4,674	5,180	5,944	7,523	8,231	8,191	7,508	5,868	4,394	4,901	8,231
Distributed Energy Programs	0	(16)	0	0	0	(133)	(111)	(154)	(66)	(54)	0	0	(111)
													0
Own Load Peak - After DE/EE	4,969	5,000	4,674	5,180	5,944	7,390	8,120	8,037	7,442	5,814	4,394	4,901	8,120

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2027	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	5,243	5,264	4,959	5,583	6,524	8,458	9,158	9,165	8,228	6,473	4,700	5,164	9,165
Energy Efficiency Programs	(133)	(104)	(134)	(326)	(404)	(792)	(841)	(812)	(634)	(437)	(89)	(119)	(812)
Own Load Peak After EE Before DE	5,110	5,160	4,825	5,257	6,120	7,666	8,317	8,353	7,594	6,036	4,611	5,045	8,353
Distributed Energy Programs	0	(23)	0	0	0	(119)	(188)	(177)	(175)	(63)	(17)	0	(177)
													0
Own Load Peak - After DE/EE	5,110	5,137	4,825	5,257	6,120	7,547	8,130	8,175	7,419	5,973	4,594	5,045	8,175

PEAK DEMAND (MW)													
YEAR: 2028	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	5,427	5,344	5,051	5,761	6,756	8,687	9,425	9,430	8,463	6,637	4,874	5,321	9,430
Energy Efficiency Programs	(149)	(116)	(199)	(351)	(439)	(887)	(804)	(735)	(748)	(490)	(200)	(133)	(735)
Own Load Peak After EE Before DE	5,278	5,228	4,852	5,410	6,317	7,800	8,620	8,695	7,715	6,146	4,674	5,188	8,695
Distributed Energy Programs	0	(27)	0	0	0	(125)	(190)	(199)	(88)	(72)	(7)	0	(199)
													0
Own Load Peak - After DE/EE	5,278	5,201	4,852	5,410	6,317	7,675	8,430	8,497	7,627	6,074	4,668	5,188	8,497

PEAK DEMAND (MW)													
YEAR: 2029	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	5,601	5,602	5,289	5,934	6,943	8,926	9,694	9,701	8,695	6,859	5,027	5,484	9,701
Energy Efficiency Programs	(165)	(129)	(187)	(373)	(438)	(986)	(774)	(1,011)	(720)	(544)	(152)	(148)	(1,011)
Own Load Peak After EE Before DE	5,436	5,473	5,102	5,561	6,506	7,940	8,921	8,690	7,974	6,315	4,876	5,336	8,690
Distributed Energy Programs	0	(30)	(32)	0	0	(131)	(407)	(168)	(279)	(82)	(15)	0	(168)
													0
Own Load Peak - After DE/EE	5,436	5,443	5,069	5,561	6,506	7,809	8,514	8,522	7,695	6,232	4,860	5,336	8,522

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)

YEAR: 2030	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	5,786	5,773	5,447	6,134	7,147	9,158	9,969	9,972	8,951	7,071	5,174	5,655	9,972
Energy Efficiency Programs	(181)	(142)	(195)	(387)	(471)	(1,083)	(909)	(872)	(913)	(598)	(223)	(163)	(872)
Own Load Peak After EE Before DE	5,605	5,631	5,252	5,747	6,677	8,076	9,060	9,100	8,038	6,473	4,951	5,492	9,100
Distributed Energy Programs	0	(27)	0	0	0	(137)	(312)	(249)	(27)	(88)	(5)	0	(249)
													0
Own Load Peak - After DE/EE	5,605	5,604	5,252	5,747	6,677	7,938	8,748	8,852	8,011	6,386	4,946	5,492	8,852

PEAK DEMAND (MW)

YEAR: 2031	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	5,956	5,948	5,623	6,318	7,346	9,435	10,246	10,254	9,176	7,272	5,330	5,814	10,246
Energy Efficiency Programs	(149)	(113)	(221)	(423)	(519)	(1,080)	(1,155)	(1,124)	(877)	(641)	(147)	(131)	(1,155)
Own Load Peak After EE Before DE	5,807	5,835	5,402	5,895	6,827	8,355	9,091	9,129	8,299	6,632	5,184	5,683	9,091
Distributed Energy Programs	0	(38)	0	0	0	(96)	(100)	(152)	(262)	(33)	(3)	0	(100)
													0
Own Load Peak - After DE/EE	5,807	5,797	5,402	5,895	6,827	8,258	8,990	8,978	8,037	6,599	5,181	5,683	8,990

PEAK DEMAND (MW)

YEAR: 2032	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	6,093	6,003	5,715	6,453	7,520	9,691	10,497	10,502	9,409	7,434	5,451	5,954	10,502
Energy Efficiency Programs	(161)	(122)	(239)	(399)	(538)	(1,159)	(1,239)	(1,209)	(934)	(691)	(150)	(141)	(1,209)
Own Load Peak After EE Before DE	5,931	5,881	5,476	6,055	6,982	8,532	9,258	9,292	8,475	6,743	5,301	5,812	9,292
Distributed Energy Programs	0	(32)	0	0	0	(106)	(141)	(132)	(310)	(27)	(1)	0	(132)
													0
Own Load Peak - After DE/EE	5,931	5,849	5,476	6,055	6,982	8,426	9,117	9,160	8,165	6,716	5,299	5,812	9,160

ATTACHMENT C.2: COINCIDENT PEAK DEMAND DISAGGREGATED BY DSM (CONTINUED)

PEAK DEMAND (MW)													
YEAR: 2033	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	6,243	6,235	5,944	6,613	7,715	9,908	10,751	10,754	9,648	7,589	5,586	6,090	10,754
Energy Efficiency Programs	(174)	(131)	(257)	(425)	(555)	(1,238)	(1,090)	(1,298)	(1,010)	(745)	(265)	(152)	(1,298)
Own Load Peak After EE Before DE	6,069	6,104	5,687	6,188	7,160	8,671	9,661	9,455	8,638	6,844	5,321	5,938	9,455
Distributed Energy Programs	0	(46)	0	0	0	(3)	(416)	(120)	(126)	(20)	0	0	(120)
													0
Own Load Peak - After DE/EE	6,069	6,058	5,687	6,188	7,160	8,668	9,245	9,335	8,512	6,824	5,321	5,938	9,335

PEAK DEMAND (MW)													
YEAR: 2034	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	6,386	6,381	6,095	6,759	7,911	10,131	11,007	11,010	9,845	7,748	5,728	6,227	11,010
Energy Efficiency Programs	(186)	(141)	(276)	(443)	(591)	(1,324)	(1,249)	(1,136)	(1,135)	(797)	(276)	(163)	(1,136)
Own Load Peak After EE Before DE	6,200	6,240	5,819	6,316	7,320	8,808	9,758	9,874	8,710	6,951	5,453	6,064	9,874
Distributed Energy Programs	0	(49)	0	0	0	(119)	(281)	(220)	0	(14)	0	0	(220)
													0
Own Load Peak - After DE/EE	6,200	6,191	5,819	6,316	7,320	8,688	9,477	9,654	8,710	6,937	5,453	6,064	9,654

PEAK DEMAND (MW)													
YEAR: 2035	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL CP
Total Own Load Peak(BAU+EV+DATA)	6,542	6,534	6,236	6,910	8,080	10,357	11,267	11,271	10,063	7,955	5,858	6,368	11,271
Energy Efficiency Programs	(198)	(150)	(294)	(456)	(586)	(1,406)	(1,219)	(1,474)	(1,087)	(850)	(225)	(174)	(1,474)
Own Load Peak After EE Before DE	6,343	6,384	5,942	6,454	7,493	8,951	10,048	9,797	8,976	7,104	5,633	6,194	9,797
Distributed Energy Programs	0	(53)	0	0	0	(121)	(486)	(73)	(295)	(8)	0	0	(73)
													0
Own Load Peak - After DE/EE	6,343	6,330	5,942	6,454	7,493	8,830	9,562	9,724	8,681	7,097	5,633	6,194	9,724

ATTACHMENT D.1(A)(1): POWER SUPPLY

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Un t/ Contract	In Service Year	Book Life/ Period	Type	Owned Capac ty (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Palo Verde															
Unit 1	1986	2047	Steam	382	1,311	382	382	[redacted]				Uranium	382	Must Run	Baseload
Unit 2	1986	2047	Steam	382	1,314	382	382	[redacted]				Uranium	382	Must Run	Baseload
Unit 3	1988	2047	Steam	382	1,312	382	382	[redacted]				Uranium	382	Must Run	Baseload
Four Corners															
Unit 4	1969	2038	Steam	485	770	485	485	[redacted]				Coal	284	Must Run	Baseload
Unit 5	1970	2038	Steam	485	770	485	485	[redacted]				Coal	284	Must Run	Baseload
Cholla															
Unit 1	1962	2025	Steam	116	116	116	116	[redacted]				Coal	30	No	Baseload
Unit 3	1980	2025	Steam	271	271	271	271	[redacted]				Coal	75	No	Baseload
Ocotillo															
Unit 1 ST	1960	2018	Steam	110	110	110	110	[redacted]				Gas	20	No	Peaking
Unit 2 ST	1960	2018	Steam	110	110	110	110	[redacted]				Gas	20	No	Peaking
Unit 1 CT	1972	2030	Combust on Turbine	55	62	62	50	[redacted]				Gas	4	No	Peaking
Unit 2 CT	1973	2030	Combust on Turbine	55	62	62	50	[redacted]				Gas	4	No	Peaking
Unit 3 CT	2019	2049	Combust on Turbine	104	104	104	102	[redacted]				Gas	26	No	Peaking
Unit 4 CT	2019	2049	Combust on Turbine	104	104	104	102	[redacted]				Gas	26	No	Peaking
Unit 5 CT	2019	2049	Combust on Turbine	104	104	104	102	[redacted]				Gas	26	No	Peaking
Unit 6 CT	2019	2049	Combust on Turbine	104	104	104	102	[redacted]				Gas	26	No	Peaking
Unit 7 CT	2019	2049	Combust on Turbine	104	104	104	102	[redacted]				Gas	26	No	Peaking
Saguaro															
Unit 1 CT	1972	2030	Combust on Turbine	55	62	62	50	[redacted]				Gas	4	No	Peaking
Unit 2 CT	1973	2030	Combust on Turbine	55	62	62	50	[redacted]				Gas	4	No	Peaking
Unit 3 CT	2002	2037	Combust on Turbine	79	79	79	76	[redacted]				Gas	40	No	Peaking
West Phoenix															
Unit 1 CC	1976	2030	Combined Cycle	88	92	92	85	[redacted]				Gas	20	No	Intermediate
Unit 2 CC	1976	2030	Combined Cycle	88	92	92	85	[redacted]				Gas	20	No	Intermediate
Unit 3 CC	1976	2030	Combined Cycle	88	92	92	85	[redacted]				Gas	50	No	Intermediate
Unit 4 CC	2001	2036	Combined Cycle	117	123	123	110	[redacted]				Gas	79	No	Intermediate
Unit 5 CC	2003	2038	Combined Cycle	516	554	554	484	[redacted]				Gas	262	No	Intermediate
Unit 1 CT	1972	2030	Combust on Turbine	55	62	62	50	[redacted]				Gas	4	No	Peaking
Unit 2 CT	1973	2030	Combust on Turbine	55	62	62	50	[redacted]				Gas	4	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Redhawk															
Unit 1 CC	2002	2037	Combined Cycle	538	550	550	521	[redacted]	[redacted]	[redacted]	[redacted]	Gas	250	No	Intermediate
Unit 2 CC	2002	2037	Combined Cycle	538	550	550	521	[redacted]	[redacted]	[redacted]	[redacted]	Gas	250	No	Intermediate
Sundance															
Unit 1 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 2 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 3 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 4 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 5 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 6 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 7 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 8 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 9 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 10 CT	2002	2037	Combustion Turbine	42	44	44	41	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Yucca															
Unit 1 CT	1971	2030	Combustion Turbine	19	22	22	18	[redacted]	[redacted]	[redacted]	[redacted]	Gas	2	No	Peaking
Unit 2 CT	1971	2030	Combustion Turbine	19	22	22	18	[redacted]	[redacted]	[redacted]	[redacted]	Gas	2	No	Peaking
Unit 3 CT	1973	2030	Combustion Turbine	55	62	62	52	[redacted]	[redacted]	[redacted]	[redacted]	Gas	5	No	Peaking
Unit 4 CT	1974	2030	Combustion Turbine	54	61	61	51	[redacted]	[redacted]	[redacted]	[redacted]	Oil	5	No	Peaking
Unit 5 CT	2008	2043	Combustion Turbine	48	49	49	47	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Unit 6 CT	2008	2043	Combustion Turbine	48	49	49	47	[redacted]	[redacted]	[redacted]	[redacted]	Gas	20	No	Peaking
Douglas															
Unit 1 CT	1972	2030	Combustion Turbine	16	19	19	15	[redacted]	[redacted]	[redacted]	[redacted]	Oil	2	No	Peaking
Microgrid															
Marine Corp Air Station Yuma (MCASY)	2016	2036	Diesel Gen Set	22	22	22	22	[redacted]	[redacted]	[redacted]	[redacted]	Oil	2.2	No	Peaking
Aligned Data Center	2016	2036	Diesel Gen Set	11	11	11	11	[redacted]	[redacted]	[redacted]	[redacted]	Oil	1.1	No	Peaking
Energy Storage Systems															
Punkin Center	2018	2038	Battery ESS	2	2	2	2	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Un t/ Contract	In Service Year	Book Life/ Period	Type	Owned Capac ty (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Renewables															
APS Existing Solar[2]	1997-2006	2037	Renewable	4	4	2	2					Solar	N/A	No	Intermittent
Aragonne Mesa Wind, New Mexico	2006	2026	Renewable	87	90	18	18					Wind	N/A	No	Intermittent
Salton Sea CE Turbo	2006	2029	Renewable	10	10	10	10					Geothermal	N/A	No	Baseload
SWMP Biomass (Snowflake Abitibi)	2008	2023	Renewable	14	14	13	13					Biomass	N/A	No	Baseload
High Lonesome Wind, New Mexico	2009	2039	Renewable	97	100	17	17					Wind	N/A	No	Intermittent
Sexton - City of Glendale Landfill	2010	2029	Renewable	3	3	3	3					Biogas	N/A	No	Baseload
Perrin Ranch Wind	2012	2036	Renewable	99	99	20	20					Wind	N/A	No	Intermittent
Solana CSP	2013	2043	Renewable	250	250	250	250					Solar	N/A	No	Intermittent
AZ Sun: Hyder II	2013	2043	Renewable	14	14	0	12					Solar	N/A	No	Intermittent
AZ Sun: Cotton Center	2011	2041	Renewable	17	17	0	10					Solar	N/A	No	Intermittent
AZ Sun: Hyder	2011	2041	Renewable	16	16	0	9					Solar	N/A	No	Intermittent
AZ Sun: Chino Valley	2012	2042	Renewable	19	19	0	8					Solar	N/A	No	Intermittent
AZ Sun: Paloma	2011	2041	Renewable	17	17	0	6					Solar	N/A	No	Intermittent
AZ Sun: Yuma Foothills	2013	2043	Renewable	35	35	0	25					Solar	N/A	No	Intermittent
AZ Sun: Gila Bend	2014	2044	Renewable	32	32	0	23					Solar	N/A	No	Intermittent
AZ Sun: Luke AFB	2015	2045	Renewable	10	10	0	7					Solar	N/A	No	Intermittent
AZ Sun: Desert Star	2015	2045	Renewable	10	10	0	7					Solar	N/A	No	Intermittent
Red Rock Solar	2016	2046	Renewable	40	40	0	25					Solar	N/A	No	Intermittent
Small Gen RFP (Ajo)	2011	2036	Renewable	5	5	0	2					Solar	N/A	No	Intermittent
Small Gen RFP (Prescott)	2011	2041	Renewable	10	10	0	4					Solar	N/A	No	Intermittent
Small Gen RFP (Saddle Mt Tonopah)	2012	2042	Renewable	15	15	0	8					Solar	N/A	No	Intermittent

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Un t/ Contract	In Service Year	Book Life/ Period	Type	Owned Capac ty (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Renewables (Continued)															
Small Gen RFP (WM Landfill)	2012	2032	Renewable	3	3	3	3	[redacted]	[redacted]	[redacted]	[redacted]	Biogas	N/A	No	Baseload
Badger-Desert Sky	2013	2042	Renewable	15	15	0	9	[redacted]	[redacted]	[redacted]	[redacted]	Solar	N/A	No	Intermittent
Recurrent Gillesp e	2013	2042	Renewable	15	15	0	9	[redacted]	[redacted]	[redacted]	[redacted]	Solar	N/A	No	Intermittent
								[redacted]	[redacted]	[redacted]	[redacted]				
Utility Scale DE															
Bagdad	2011	2036	Renewable	13	13	0	7	[redacted]	[redacted]	[redacted]	[redacted]	Solar	N/A	No	Intermittent
Schools and Gov't & Other DE Programs	2012-2020	2035	Renewable	24	24	0	1	[redacted]	[redacted]	[redacted]	[redacted]	Solar	N/A	No	Intermittent
								[redacted]	[redacted]	[redacted]	[redacted]				
Contracts															
[redacted]	1955	2022	Contract	38	38	38	37	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Baseload
PACIFICORP Div Exch	1990	2020	Contract	480	480	(480)	480	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Intermediate
AGX Load	2017	2032	Contract	158	158	158	158	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Baseload
								[redacted]	[redacted]	[redacted]	[redacted]				
DR Contract (on-peak) # 1	2010	2025	Contract	25	26	0	12	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
								[redacted]	[redacted]	[redacted]	[redacted]				
CC Tolling # 1[6]	2020	2025	Tolling	565	565	0	565	[redacted]	[redacted]	[redacted]	[redacted]	Gas	315	No	Intermediate
								[redacted]	[redacted]	[redacted]	[redacted]				
CC Tolling # 2 1A [6]	2020	2026	Tolling	570	570	0	570	[redacted]	[redacted]	[redacted]	[redacted]	Gas	310	No	Intermediate
								[redacted]	[redacted]	[redacted]	[redacted]				
CC Tolling # 3 1A [7]	2021	2027	Tolling	463	463	0	463	[redacted]	[redacted]	[redacted]	[redacted]	Gas	225	No	Intermediate

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Un t/ Contract	In Service Year	Book Life/ Period	Type	Owned Capac ty (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Units: Bridge Portfolio															
Unit 1 Future CT	2028	2068	Combust on Turbine	384	389	389	362	[redacted]	[redacted]	[redacted]	[redacted]	Gas	175	No	Peaking
Unit 2 Future CT	2031	2071	Combust on Turbine	384	389	389	362	[redacted]	[redacted]	[redacted]	[redacted]	Gas	175	No	Peaking
Microgrid 1	2021	2041	Diesel Gen Set	6	6	6	6	[redacted]	[redacted]	[redacted]	[redacted]	Oil	0.6	No	Peaking
Microgrid 2	2025	2045	Diesel Gen Set	25	25	25	25	[redacted]	[redacted]	[redacted]	[redacted]	Oil	2.5	No	Peaking
Microgrid 3	2027	2047	Diesel Gen Set	25	25	25	25	[redacted]	[redacted]	[redacted]	[redacted]	Oil	2.5	No	Peaking
Microgrid 4	2031	2051	Diesel Gen Set	50	50	50	50	[redacted]	[redacted]	[redacted]	[redacted]	Oil	5.0	No	Peaking
Microgrid 5	2033	2053	Diesel Gen Set	25	25	25	25	[redacted]	[redacted]	[redacted]	[redacted]	Oil	2.5	No	Peaking
Solar + Storage System PPA 1	2022	2037	Renewable + Battery ESS	50	50	43	43	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 1 [3,4]	2022-2023	2062	Renewable + Battery ESS	150	150	150	150	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 2 [3]	2024	2064	Renewable + Battery ESS	200	200	200	200	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 3 [3]	2025	2065	Renewable + Battery ESS	500	500	483	483	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 4 [3]	2026	2066	Renewable + Battery ESS	250	250	235	235	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 5 [3]	2027	2067	Renewable + Battery ESS	200	200	181	181	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 6 [3]	2028	2068	Renewable + Battery ESS	350	350	306	306	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 7 [3]	2029	2069	Renewable + Battery ESS	200	200	169	169	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 8 [3]	2030	2070	Renewable + Battery ESS	250	250	206	206	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 9 [3]	2031	2071	Renewable + Battery ESS	550	550	437	437	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 10 [3]	2032	2072	Renewable + Battery ESS	350	350	268	268	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking
Solar + Storage System 11 [3]	2033	2073	Renewable + Battery ESS	250	250	185	185	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Un t/ Contract	In Service Year	Book Life/ Period	Type	Owned Capac ty (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Units: Bridge Portfolio (Continued)															
Solar + Storage System 12 [3]	2034	2074	Renewable + Battery ESS	400	400	286	286					N/A	N/A	No	Peaking
Solar + Storage System 13 [3]	2035	2075	Renewable + Battery ESS	400	400	273	273					N/A	N/A	No	Peaking
Energy Storage System PPA 1	2022	2042	Renewable + Battery ESS	100	100	73	73					N/A	N/A	No	Peaking
Energy Storage System PPA 2	2022	2042	Renewable + Battery ESS	50	50	36	36					N/A	N/A	No	Peaking
Energy Storage System 1	2023	2043	Renewable + Battery ESS	200	200	140	140					N/A	N/A	No	Peaking
Energy Storage System 2	2031	2051	Battery ESS	400	400	274	274					N/A	N/A	No	Peaking
Future Renewables: Bridge Portfolio															
New Wind 1	2022	2042	Renewable	250	250	64	64					Wind	N/A	No	Intermittent
New Wind 2	2023	2043	Renewable	112	112	42	42					Wind	N/A	No	Intermittent
New Wind 3	2023	2043	Renewable	200	200	49	49					Wind	N/A	No	Intermittent
New Wind 4	2025	2045	Renewable	350	350	133	133					Wind	N/A	No	Intermittent
New Wind 5	2027	2047	Renewable	88	88	32	32					Wind	N/A	No	Intermittent
New Wind 6	2027	2047	Renewable	150	150	54	54					Wind	N/A	No	Intermittent
New Wind 7	2029	2049	Renewable	200	200	68	68					Wind	N/A	No	Intermittent
New Wind 8	2030	2050	Renewable	250	250	83	83					Wind	N/A	No	Intermittent
New Wind 9	2031	2051	Renewable	250	250	81	81					Wind	N/A	No	Intermittent
New Wind 10	2033	2053	Renewable	250	250	74	74					Wind	N/A	No	Intermittent
New Wind 11	2035	2055	Renewable	250	250	69	69					Wind	N/A	No	Intermittent
Future Contracts: Bridge Portfolio															
Future CC Tolling #1 1A	2026	2035	Tolling	565	565	565	565					Gas	315	No	Intermediate
Future CC Tolling #2 1A	2027	2035	Tolling	570	570	570	570					Gas	310	No	Intermediate
Future DR Contract (on-peak) # 1	2020	2035	Contract	10	10	0	5					N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Un t/ Contract	In Service Year	Book Life/ Period	Type	Owned Capac ty (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Contracts: Bridge Portfolio (Continued)															
Future DR Contract (on-peak) # 2	2021	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 3	2022	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 4	2023	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 5	2024	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 6	2025	2035	Contract	100	100	0	50					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 7	2026	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 8	2027	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 9	2028	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 10	2029	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 11	2030	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 12	2031	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 13	2032	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 14	2033	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 15	2034	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 16	2035	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Un t/ Contract	In Service Year	Book Life/ Period	Type	Owned Capac ty (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Units: Shift Portfolio															
Microgrid 1	2021	2041	Diesel Gen Set	6	6	6	6					Oil	0.6	No	Peaking
Microgrid 2	2025	2045	Diesel Gen Set	25	25	25	25					Oil	2.5	No	Peaking
Microgrid 3	2030	2050	Diesel Gen Set	25	25	25	25					Oil	2.5	No	Peaking
Microgrid 4	2031	2051	Diesel Gen Set	75	75	75	75					Oil	7.5	No	Peaking
Solar + Storage System PPA 1	2022	2037	Renewable + Battery ESS	50	50	43	43					N/A	N/A	No	Peaking
Solar + Storage System 1 [3,4]	2022-2023	2062	Renewable + Battery ESS	150	150	150	150					N/A	N/A	No	Peaking
Solar + Storage System 2 [3]	2024	2064	Renewable + Battery ESS	200	200	200	200					N/A	N/A	No	Peaking
Solar + Storage System 3 [3]	2025	2065	Renewable + Battery ESS	500	500	487	487					N/A	N/A	No	Peaking
Solar + Storage System 4 [3]	2026	2066	Renewable + Battery ESS	250	250	239	239					N/A	N/A	No	Peaking
Solar + Storage System 5 [3]	2027	2067	Renewable + Battery ESS	250	250	226	226					N/A	N/A	No	Peaking
Solar + Storage System 6 [3]	2028	2068	Renewable + Battery ESS	750	750	653	653					N/A	N/A	No	Peaking
Solar + Storage System 7 [3]	2029	2069	Renewable + Battery ESS	200	200	167	167					N/A	N/A	No	Peaking
Solar + Storage System 8 [3]	2030	2070	Renewable + Battery ESS	150	150	122	122					N/A	N/A	No	Peaking
Solar + Storage System 9 [3]	2031	2071	Renewable + Battery ESS	850	850	654	654					N/A	N/A	No	Peaking
Solar + Storage System 10 [3]	2032	2072	Renewable + Battery ESS	500	500	363	363					N/A	N/A	No	Peaking
Solar + Storage System 11 [3]	2033	2073	Renewable + Battery ESS	400	400	276	276					N/A	N/A	No	Peaking
Solar + Storage System 12 [3]	2034	2074	Renewable + Battery ESS	600	600	392	392					N/A	N/A	No	Peaking
Solar + Storage System 13 [3]	2035	2075	Renewable + Battery ESS	600	600	366	366					N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Units: Shift Portfolio (Continued)															
Energy Storage System PPA 1	2022	2042	Renewable + Battery ESS	100	100	73	73					N/A	N/A	No	Peaking
Energy Storage System PPA 2	2022	2042	Renewable + Battery ESS	50	50	36	36					N/A	N/A	No	Peaking
Energy Storage System 1	2023	2043	Renewable + Battery ESS	200	200	140	140					N/A	N/A	No	Peaking
Energy Storage System 2	2031	2051	Battery ESS	700	700	468	468					N/A	N/A	No	Peaking
Future Renewables: Shift Portfolio															
New Wind 1	2022	2042	Renewable	250	250	64	64					Wind	N/A	No	Intermittent
New Wind 2	2023	2043	Renewable	112	112	42	42					Wind	N/A	No	Intermittent
New Wind 3	2023	2043	Renewable	200	200	49	49					Wind	N/A	No	Intermittent
New Wind 4	2025	2045	Renewable	350	350	133	133					Wind	N/A	No	Intermittent
New Wind 5	2027	2047	Renewable	88	88	32	32					Wind	N/A	No	Intermittent
New Wind 6	2027	2047	Renewable	150	150	54	54					Wind	N/A	No	Intermittent
New Wind 7	2029	2049	Renewable	150	150	51	51					Wind	N/A	No	Intermittent
New Wind 8	2030	2050	Renewable	250	250	83	83					Wind	N/A	No	Intermittent
New Wind 9	2031	2051	Renewable	400	400	129	129					Wind	N/A	No	Intermittent
New Wind 10	2033	2053	Renewable	250	250	74	74					Wind	N/A	No	Intermittent
New Wind 11	2035	2055	Renewable	300	300	81	81					Wind	N/A	No	Intermittent
Future Contracts: Shift Portfolio															
Future CC Tolling #1 1A	2026	2035	Tolling	565	565	565	565					Gas	315	No	Intermediate
Future CC Tolling #2 1A	2027	2035	Tolling	570	570	570	570					Gas	310	No	Intermediate
Future DR Contract (on-peak) # 1	2020	2035	Contract	10	10	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 2	2021	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 3	2022	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Un t/ Contract	In Service Year	Book Life/ Period	Type	Owned Capac ty (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Contracts: Shift Portfolio (Continued)															
Future DR Contract (on-peak) # 4	2023	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 5	2024	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 6	2025	2035	Contract	100	100	0	50					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 7	2026	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 8	2027	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 9	2028	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 10	2029	2035	Contract	125	125	0	63					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 11	2030	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 12	2031	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 13	2032	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 14	2033	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 15	2034	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 16	2035	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Units: Accelerate Portfolio															
Microgrid 1	2021	2041	Diesel Gen Set	6	6	6	6					Oil	0.6	No	Peaking
Solar + Storage System PPA 1	2022	2037	Renewable + Battery ESS	50	50	43	43					N/A	N/A	No	Peaking
Solar + Storage System 1 [3,4]	2022-2023	2062	Renewable + Battery ESS	150	150	150	150					N/A	N/A	No	Peaking
Solar + Storage System 2 [3]	2024	2059	Renewable + Battery ESS	200	200	200	200					N/A	N/A	No	Peaking
Solar + Storage System 3 [3]	2025	2060	Renewable + Battery ESS	550	550	535	535					N/A	N/A	No	Peaking
Solar + Storage System 4 [3]	2026	2061	Renewable + Battery ESS	750	750	706	706					N/A	N/A	No	Peaking
Solar + Storage System 5 [3]	2027	2062	Renewable + Battery ESS	750	750	653	653					N/A	N/A	No	Peaking
Solar + Storage System 6 [3]	2028	2063	Renewable + Battery ESS	750	750	609	609					N/A	N/A	No	Peaking
Solar + Storage System 7 [3]	2029	2064	Renewable + Battery ESS	350	350	262	262					N/A	N/A	No	Peaking
Solar + Storage System 8 [3]	2030	2065	Renewable + Battery ESS	500	500	347	347					N/A	N/A	No	Peaking
Solar + Storage System 9 [3]	2031	2066	Renewable + Battery ESS	1100	1100	701	701					N/A	N/A	No	Peaking
Solar + Storage System 10 [3]	2032	2067	Renewable + Battery ESS	750	750	443	443					N/A	N/A	No	Peaking
Solar + Storage System 11 [3]	2033	2068	Renewable + Battery ESS	650	650	362	362					N/A	N/A	No	Peaking
Solar + Storage System 12 [3]	2034	2069	Renewable + Battery ESS	750	750	393	393					N/A	N/A	No	Peaking
Solar + Storage System 13 [3]	2035	2070	Renewable + Battery ESS	750	750	370	370					N/A	N/A	No	Peaking
Energy Storage System PPA 1	2022	2042	Renewable + Battery ESS	100	100	73	73					N/A	N/A	No	Peaking
Energy Storage System PPA 2	2022	2042	Renewable + Battery ESS	50	50	36	36					N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Unit/ Contract	In Service Year	Book Life/ Period	Type	Owned Capacity (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) [5]	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) [1,9]	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking [8]
Future Units: Accelerate Portfolio (Continued)															
Energy Storage System 1	2023	2043	Renewable + Battery ESS	200	200	140	140	[redacted]				N/A	N/A	No	Peaking
Energy Storage System 2	2026	2046	Battery ESS	150	150	97	97					N/A	N/A	No	Peaking
Energy Storage System 3	2027	2047	Battery ESS	300	300	187	187					N/A	N/A	No	Peaking
Energy Storage System 4	2028	2048	Battery ESS	300	300	188	188					N/A	N/A	No	Peaking
Energy Storage System 5	2031	2051	Battery ESS	1100	1100	624	624					N/A	N/A	No	Peaking
Energy Storage System 6	2032	2052	Battery ESS	150	150	80	80					N/A	N/A	No	Peaking
Energy Storage System 7	2034	2054	Battery ESS	150	150	73	73					N/A	N/A	No	Peaking
Future Renewables: Accelerate Portfolio															
New Wind 1	2022	2042	Renewable	250	250	64	64	[redacted]				Wind	N/A	No	Intermittent
New Wind 2	2023	2043	Renewable	112	112	42	42					Wind	N/A	No	Intermittent
New Wind 3	2023	2043	Renewable	200	200	49	49					Wind	N/A	No	Intermittent
New Wind 4	2025	2045	Renewable	250	250	96	96					Wind	N/A	No	Intermittent
New Wind 5	2027	2047	Renewable	88	88	32	32					Wind	N/A	No	Intermittent
New Wind 6	2028	2048	Renewable	200	200	71	71					Wind	N/A	No	Intermittent
New Wind 7	2029	2049	Renewable	200	200	68	68					Wind	N/A	No	Intermittent
New Wind 8	2031	2051	Renewable	450	450	147	147					Wind	N/A	No	Intermittent
New Wind 9	2033	2053	Renewable	250	250	75	75					Wind	N/A	No	Intermittent
New Wind 10	2035	2055	Renewable	250	250	69	69					Wind	N/A	No	Intermittent
Future Contracts: Accelerate Portfolio															
Future Biomass PPA 1	2023	2035	Contract	25	25	25	25	[redacted]				N/A	N/A	No	Intermittent
Future DR Contract (on-peak) # 1	2020	2035	Contract	10	10	0	5					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 2	2021	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking

ATTACHMENT D.1(A)(1): POWER SUPPLY (CONTINUED)

POWER SUPPLY - ESTIMATES FOR 2020-2035															
	B.1(a)		B.1(b)	B.1(c)	B.1(d)			B.1(f)(a)			B.1(h)	B.1(l)	B.1(m)	B.1(n)	B.1(o)
Plant/ Un t/ Contract	In Service Year	Book Life/ Period	Type	Owned Capac ty (MW)	Max Capacity (MW)	Winter Capacity (MW)	Summer Capacity (MW)	50% Load Heat Rate (Btu/kWh) 5	75% Load Heat Rate (Btu/kWh)	100% Load Heat Rate (Btu/kWh)	Variable O&M Cost ($/MWh) 1,9	Fuel	Min Cap (MW)	Must Run?	Baseload Intermediate Peaking 8
Future Contracts: Accelerate Portfolio (Continued)															
Future DR Contract (on-peak) # 3	2022	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 4	2023	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 5	2024	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 6	2025	2035	Contract	100	100	0	50					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 7	2026	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 8	2027	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 9	2028	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 10	2029	2035	Contract	125	125	0	63					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 11	2030	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 12	2031	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 13	2032	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 14	2033	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 15	2034	2035	Contract	25	25	0	13					N/A	N/A	No	Peaking
Future DR Contract (on-peak) # 16	2035	2035	Contract	75	75	0	38					N/A	N/A	No	Peaking

Notes:
(1) Fuel not included
(2) Consists of several small solar projects of 17.36 yrs book life
(3) Assumes ESS replacement
(4) PV in 2022, ESS in 2023
(5) 55% heat rate for future CT units
(6) Jun - Sep Summer months only
(7) May - Oct Summer months only
(8) For purposes of compliance with Rule B.1(o), intermittent is considered intermediate.
(9) 2019$

ATTACHMENT D.1(A)(2)-1: ANNUAL CAPACITY FACTOR - BRIDGE PORTFOLIO

Annual Capacity Factor - B.1(e)																
Plant/ Unit/ Contract	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Palo Verde																
Unit 1	[redacted]															
Unit 2	[redacted]															
Unit 3	[redacted]															
Four Corners																
Unit 4	[redacted]															
Unit 5	[redacted]															
Cholla																
Unit 1	[redacted]															
Unit 3	[redacted]															
Ocotillo																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Unit 7 CT	[redacted]															
Saguaro																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
West Phoenix																
Unit 1 CC	[redacted]															
Unit 2 CC	[redacted]															
Unit 3 CC	[redacted]															
Unit 4 CC	[redacted]															
Unit 5 CC	[redacted]															
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Redhawk																
Unit 1 CC	[redacted]															
Unit 2 CC	[redacted]															
Sundance																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Unit 7 CT	[redacted]															
Unit 8 CT	[redacted]															
Unit 9 CT	[redacted]															
Unit 10 CT	[redacted]															

ATTACHMENT D.1(A)(2)-1: ANNUAL CAPACITY FACTOR - BRIDGE PORTFOLIO (CONTINUED)

	Annual Capacity Factor - B.1(e)															
Plant/ Unit/ Contract	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Yucca																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Douglas																
Unit 1 CT	[redacted]															
Microgrid																
Aligned Data Center	[redacted]															
Marine Corp Air Station Yuma (MCASY)	[redacted]															
Energy Storage Systems																
Punkin Center	[redacted]															
Renewables																
Aragonne Mesa Wind, New Mexico	[redacted]															
Salton Sea CE Turbo	[redacted]															
SWMP Biomass (Snowflake Abitibi)	[redacted]															
High Lonesome Wind, New Mexico	[redacted]															
Perrin Ranch Wind	[redacted]															
	[redacted]															
Solana CSP	[redacted]															
	[redacted]															
AZ Sun: Hyder II	[redacted]															
AZ Sun: Cotton Center	[redacted]															
AZ Sun: Hyder	[redacted]															
AZ Sun: Chino Valley	[redacted]															
AZ Sun: Paloma	[redacted]															
AZ Sun: Yuma Foothills	[redacted]															
AZ Sun: Gila Bend	[redacted]															
AZ Sun: Luke AFB	[redacted]															
AZ Sun: Desert Star	[redacted]															
Red Rock Solar	[redacted]															
	[redacted]															
Small Gen RFP (Ajo)	[redacted]															
Small Gen RFP (Prescott)	[redacted]															
Small Gen RFP (Saddle Mt Tonopah)	[redacted]															
Small Gen RFP (WM Landfill)	[redacted]															
Badger-Desert Sky	[redacted]															
Recurrent Gillespie	[redacted]															

ATTACHMENT D.1(A)(2)-1: ANNUAL CAPACITY FACTOR - BRIDGE PORTFOLIO (CONTINUED)

Annual Capacity Factor - B.1(e)																
Plant/ Unit/ Contract	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Utility Scale DE																
Bagdad	[redacted]															
Schools and Gov't & Other DE Programs	[redacted]															
Contracts																
SRP - Firm / Eastern Mining Load	[redacted]															
PACIFICORP Div Exch	[redacted]															
AGX Load	[redacted]															
	[redacted]															
CC Tolling # 1	[redacted]															
	[redacted]															
CC Tolling # 2	[redacted]															
	[redacted]															
CC Tolling # 3	[redacted]															
	[redacted]															
Short term Purchases	[redacted]															
Future Units																
Unit 1 Future CT	[redacted]															
Unit 2 Future CT	[redacted]															
Future Microgrids	[redacted]															
Energy Storage System PPA 1	[redacted]															
Energy Storage System PPA 2	[redacted]															
Energy Storage Systems	[redacted]															
Future Renewables																
Arizona Wind	[redacted]															
New Mexico Wind	[redacted]															
Solar + Storage Systems	[redacted]															
Future Contracts																
Future CC Tolling #1	[redacted]															
	[redacted]															
Future CC Tolling #2	[redacted]															

ATTACHMENT D.1(A)(2)-2: ANNUAL CAPACITY FACTOR - SHIFT PORTFOLIO

	Annual Capacity Factor - B.1(e)															
Plant/ Unit/ Contract	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Palo Verde																
Unit 1	[redacted]															
Unit 2	[redacted]															
Unit 3	[redacted]															
Four Corners																
Unit 4	[redacted]															
Unit 5	[redacted]															
Cholla																
Unit 1	[redacted]															
Unit 3	[redacted]															
Ocotillo																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Unit 7 CT	[redacted]															
Saguaro																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
West Phoenix																
Unit 1 CC	[redacted]															
Unit 2 CC	[redacted]															
Unit 3 CC	[redacted]															
Unit 4 CC	[redacted]															
Unit 5 CC	[redacted]															
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Redhawk																
Unit 1 CC	[redacted]															
Unit 2 CC	[redacted]															
Sundance																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Unit 7 CT	[redacted]															
Unit 8 CT	[redacted]															
Unit 9 CT	[redacted]															
Unit 10 CT	[redacted]															

ATTACHMENT D.1(A)(2)-2: ANNUAL CAPACITY FACTOR - SHIFT PORTFOLIO (CONTINUED)

	Annual Capacity Factor - B.1(e)															
Plant/ Unit/ Contract	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Yucca																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Douglas																
Unit 1 CT	[redacted]															
Microgrid																
Aligned Data Center	[redacted]															
Marine Corp Air Station Yuma (MCASY)	[redacted]															
Energy Storage Systems																
Punkin Center	[redacted]															
Renewables																
Aragonne Mesa Wind, New Mexico	[redacted]															
Salton Sea CE Turbo	[redacted]															
SWMP Biomass (Snowflake Abitibi)	[redacted]															
High Lonesome Wind, New Mexico	[redacted]															
Perrin Ranch Wind	[redacted]															
	[redacted]															
Solana CSP	[redacted]															
	[redacted]															
AZ Sun: Hyder II	[redacted]															
AZ Sun: Cotton Center	[redacted]															
AZ Sun: Hyder	[redacted]															
AZ Sun: Chino Valley	[redacted]															
AZ Sun: Paloma	[redacted]															
AZ Sun: Yuma Foothills	[redacted]															
AZ Sun: Gila Bend	[redacted]															
AZ Sun: Luke AFB	[redacted]															
AZ Sun: Desert Star	[redacted]															
Red Rock Solar	[redacted]															
	[redacted]															
Small Gen RFP (Ajo)	[redacted]															
Small Gen RFP (Prescott)	[redacted]															
Small Gen RFP (Saddle Mt Tonopah)	[redacted]															
Small Gen RFP (WM Landfill)	[redacted]															
Badger-Desert Sky	[redacted]															
Recurrent Gillespie	[redacted]															

ATTACHMENT D.1(A)(2)-2 – ANNUAL CAPACITY FACTOR - SHIFT PORTFOLIO (CONTINUED)

	Annual Capacity Factor - B.1(e)															
Plant/ Unit/ Contract	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Utility Scale DE																
Bagdad	[redacted]															
Schools and Gov't & Other DE Programs	[redacted]															
Contracts																
SRP - Firm / Eastern Mining Load	[redacted]															
PACIFICORP Div Exch	[redacted]															
AGX Load	[redacted]															
	[redacted]															
CC Tolling # 1	[redacted]															
	[redacted]															
CC Tolling # 2	[redacted]															
	[redacted]															
CC Tolling # 3	[redacted]															
	[redacted]															
Short term Purchases	[redacted]															
Future Units																
Future Microgrids	[redacted]															
Energy Storage System PPA 1	[redacted]															
Energy Storage System PPA 2	[redacted]															
Energy Storage Systems	[redacted]															
Future Renewables																
Arizona Wind	[redacted]															
New Mexico Wind	[redacted]															
Solar + Storage Systems	[redacted]															
Future Contracts																
Future CC Tolling #1	[redacted]															
	[redacted]															
Future CC Tolling #2	[redacted]															

ATTACHMENT D.1(A)(2)-3: ANNUAL CAPACITY FACTOR - ACCELERATE PORTFOLIO

Annual Capacity Factor - B.1(e)																
Plant/ Unit/ Contract	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Palo Verde																
Unit 1	[redacted]															
Unit 2	[redacted]															
Unit 3	[redacted]															
Four Corners																
Unit 4	[redacted]															
Unit 5	[redacted]															
Cholla																
Unit 1	[redacted]															
Unit 3	[redacted]															
Ocotillo																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Unit 7 CT	[redacted]															
Saguaro																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
West Phoenix																
Unit 1 CC	[redacted]															
Unit 2 CC	[redacted]															
Unit 3 CC	[redacted]															
Unit 4 CC	[redacted]															
Unit 5 CC	[redacted]															
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Redhawk																
Unit 1 CC	[redacted]															
Unit 2 CC	[redacted]															
Sundance																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Unit 7 CT	[redacted]															
Unit 8 CT	[redacted]															
Unit 9 CT	[redacted]															
Unit 10 CT	[redacted]															

ATTACHMENT D.1(A)(2)-3: ANNUAL CAPACITY FACTOR - ACCELERATE PORTFOLIO (CONTINUED)

	Annual Capacity Factor - B.1(e)															
Plant/ Unit/ Contract	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Yucca																
Unit 1 CT	[redacted]															
Unit 2 CT	[redacted]															
Unit 3 CT	[redacted]															
Unit 4 CT	[redacted]															
Unit 5 CT	[redacted]															
Unit 6 CT	[redacted]															
Douglas																
Unit 1 CT	[redacted]															
Microgrid																
Aligned Data Center	[redacted]															
Marine Corp Air Station Yuma (MCASY)	[redacted]															
Energy Storage Systems																
Punkin Center	[redacted]															
Renewables																
Aragonne Mesa Wind, New Mexico	[redacted]															
Salton Sea CE Turbo	[redacted]															
SWMP Biomass (Snowflake Abitibi)	[redacted]															
High Lonesome Wind, New Mexico	[redacted]															
Perrin Ranch Wind	[redacted]															
	[redacted]															
Solana CSP	[redacted]															
	[redacted]															
AZ Sun: Hyder II	[redacted]															
AZ Sun: Cotton Center	[redacted]															
AZ Sun: Hyder	[redacted]															
AZ Sun: Chino Valley	[redacted]															
AZ Sun: Paloma	[redacted]															
AZ Sun: Yuma Foothills	[redacted]															
AZ Sun: Gila Bend	[redacted]															
AZ Sun: Luke AFB	[redacted]															
AZ Sun: Desert Star	[redacted]															
Red Rock Solar	[redacted]															
	[redacted]															
Small Gen RFP (Ajo)	[redacted]															
Small Gen RFP (Prescott)	[redacted]															
Small Gen RFP (Saddle Mt Tonopah)	[redacted]															
Small Gen RFP (WM Landfill)	[redacted]															
Badger-Desert Sky	[redacted]															
Recurrent Gillespie	[redacted]															

ATTACHMENT D.1(A)(2)-3: ANNUAL CAPACITY FACTOR - ACCELERATE PORTFOLIO (CONTINUED)

Annual Capacity Factor - B.1(e)																
Plant/ Unit/ Contract	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Utility Scale DE																
Bagdad																
Schools and Gov't & Other DE Programs																
Contracts																
SRP - Firm / Eastern Mining Load																
PACIFICORP Div Exch																
AGX Load																
CC Tolling # 1																
CC Tolling # 2																
CC Tolling # 3																
Short term Purchases																
Future Units																
Future Microgrids																
Energy Storage System PPA 1																
Energy Storage System PPA 2																
Energy Storage Systems																
Future Renewables																
Arizona Wind																
New Mexico Wind																
Solar + Storage Systems																
Future Contracts																
Future Biomass																

ATTACHMENT D.1(A)3-1: AVERAGE HEAT RATE - BRIDGE PORTFOLIO

Average Heat Rate - B.1(f)(b) (Btu/kWh)																
UNIT	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Palo Verde																
Unit 1	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385
Unit 2	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361
Unit 3	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377
Four Corners																
Unit 4	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687				
Unit 5	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687				
Cholla																
Unit 1	10,828	10,629	10,517	10,551	10,647	11,431										
Unit 3	10,852	10,820	10,762	10,750	10,831	11,268										
Ocotillo																
Unit 1 CT	25,883	53,795	32,685	28,040	40,842	55,939	39,218	45,969	53,477	45,775	54,516	-	80,755	-	40,939	84,214
Unit 2 CT	22,995	47,883	30,354	28,465	36,920	54,007	37,889	40,610	55,291	38,861	48,136	-	-	80,755	78,358	88,016
Unit 3 CT	9,732	9,551	9,257	9,585	9,798	9,917	9,590	9,889	9,662	9,521	9,599	10,268	10,026	10,402	10,138	10,462
Unit 4 CT	9,659	9,499	9,271	9,337	9,744	9,787	9,474	9,632	9,544	9,261	9,485	10,157	9,922	10,316	9,993	10,312
Unit 5 CT	9,538	9,436	9,276	9,363	9,656	9,629	9,350	9,532	9,532	9,370	9,724	9,926	9,737	10,089	9,787	10,103
Unit 6 CT	9,713	9,660	9,292	9,558	9,851	9,786	9,525	9,814	9,778	9,762	9,861	10,086	9,967	10,335	10,111	10,469
Unit 7 CT	9,554	9,521	9,250	9,367	9,711	9,876	9,419	9,631	9,582	9,427	9,669	10,050	9,776	10,157	9,807	10,131
Saguaro																
Unit 1 CT	27,185	55,204	24,104	27,390	37,711	55,784	38,211	42,251	51,298	42,356	46,928	-	-	-	18,441	-
Unit 2 CT	30,081	55,461	21,507	29,406	39,780	53,992	34,291	37,483	48,699	43,014	44,423	-	-	-	22,566	-
Unit 3 CT	12,525	13,944	12,424	13,177	13,465	14,198	13,402	14,015	13,955	13,863	13,886	-	11,714	-	11,720	14,391
West Phoenix																
Unit 1 CC	9,950	10,667	9,301	9,415	10,270	11,810	9,759	10,493	11,233	9,696	10,568	9,374	10,319	10,664	10,732	11,371
Unit 2 CC	10,006	10,229	9,338	9,452	10,445	11,918	9,811	10,283	11,317	9,733	10,496	9,338	9,932	10,638	10,451	11,135
Unit 3 CC	9,601	9,784	9,236	9,322	9,688	10,364	9,635	9,903	10,110	9,487	9,713	9,431	9,465	9,462	9,439	9,374
Unit 4 CC	8,339	8,548	8,158	8,224	8,317	8,547	8,239	8,290	8,416	8,189	8,334	8,118	8,121	8,122	8,115	8,122
Unit 5 CC	7,584	7,648	7,527	7,553	7,558	7,632	7,518	7,521	7,620	7,468	7,544	7,522	7,597	7,622	7,600	7,633
Unit 1 CT	26,047	55,275	22,403	29,427	34,910	50,218	29,783	38,529	44,991	37,312	44,206	-	79,949	79,185	73,940	79,785
Unit 2 CT	27,427	58,703	24,643	33,300	36,926	52,179	30,904	39,539	46,627	38,692	46,636	-	80,239	79,429	75,904	81,192
Redhawk																
Unit 1 CC	7,068	7,101	7,030	6,976	7,052	7,063	7,006	6,966	7,134	6,950	7,043	6,920	6,960	6,969	6,973	6,976
Unit 2 CC	7,090	7,131	7,015	6,992	7,043	7,049	7,001	6,938	7,137	6,965	7,040	6,929	6,948	6,947	6,946	6,955
Sundance																
Unit 1 CT	10,549	10,738	10,496	10,537	10,173	10,669	10,087	10,104	10,056	10,217	10,109	11,299	11,076	11,626	11,113	11,578
Unit 2 CT	10,646	10,875	10,666	10,773	10,246	10,835	10,134	10,366	10,011	10,174	10,047	11,192	11,125	11,139	11,198	11,036
Unit 3 CT	10,740	10,968	10,743	10,796	10,307	11,409	10,137	10,265	10,197	9,985	10,046	11,297	11,142	11,435	10,989	11,694
Unit 4 CT	10,779	11,025	10,739	10,955	10,639	11,194	10,280	9,921	10,201	10,188	10,271	10,900	11,167	11,474	11,190	11,235
Unit 5 CT	10,842	11,016	10,858	11,041	10,664	11,083	10,305	10,581	10,230	9,994	10,143	11,024	11,144	11,411	11,144	11,634
Unit 6 CT	10,914	11,149	10,968	10,974	10,646	11,279	10,300	10,446	10,267	10,113	10,291	11,097	11,062	11,617	11,108	11,999
Unit 7 CT	10,504	10,643	10,440	10,458	10,059	10,761	10,032	10,112	10,049	10,066	10,060	11,100	10,933	11,249	11,067	11,418
Unit 8 CT	10,870	11,065	10,856	11,009	10,840	11,259	10,315	10,313	10,105	10,298	10,084	11,248	11,045	11,082	10,977	11,829
Unit 9 CT	10,651	10,745	10,593	10,527	10,251	11,099	10,093	10,331	10,083	10,070	10,101	11,245	11,142	11,450	11,046	11,494
Unit 10 CT	10,609	10,819	10,510	10,774	10,125	11,291	10,142	10,329	9,984	10,234	10,099	11,302	11,131	11,343	11,068	11,022
Yucca																
Unit 1 CT	25,623	43,856	23,189	29,029	33,083	46,958	29,174	44,223	39,624	38,255	36,775	64,992	62,155	61,450	52,721	61,693
Unit 2 CT	26,505	44,875	23,460	28,394	33,217	46,561	29,553	42,556	39,856	37,725	37,428	64,992	62,618	62,308	50,294	63,567
Unit 3 CT	15,177	35,459	17,550	21,077	24,306	37,847	24,762	36,966	34,530	32,957	33,867	31,777	47,890	57,999	51,009	59,347
Unit 4 CT	62,466	63,084	64,691	65,853	64,246	62,270	65,658	64,586	62,049	61,171	64,280	-	-	-	-	-
Unit 5 CT	10,471	10,522	10,539	10,911	10,676	11,341	10,115	10,633	10,208	10,294	9,969	11,338	10,933	12,104	11,236	11,965
Unit 6 CT	10,584	10,699	10,651	11,065	10,806	11,015	10,085	10,940	10,252	10,534	10,023	11,159	10,873	12,079	11,170	12,131

ATTACHMENT D.1(A)3-1: AVERAGE HEAT RATE - BRIDGE PORTFOLIO (CONTINUED)

Average Heat Rate - B.1(f)(b) (Btu/kWh)																
UNIT	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Douglas																
Unit 1 CT	56,494	55,787	57,052	56,985	59,002	53,351	57,955	53,209	58,891	59,054	55,604	-	48,535	-	48,535	-
Mircrogrids																
Aligned	8,300	8,300	8,300	-	-	-	8,300	-	8,300	-	-	-	-	-	-	-
MCASY	8,300	8,300	8,300	-	8,300	8,300	8,300	8,300	8,300	-	-	-	8,300	8,300	8,300	8,300
Future Units																
Unit 1 CT	-	-	-	-	-	-	-	-	9,579	9,518	9,734	9,486	9,413	9,444	9,455	9,492
Unit 2 CT	-	-	-	-	-	-	-	-	-	-	-	9,388	9,393	9,421	9,398	9,431
Future Microgrids	-	8,300	8,300	-	-	8,300	8,300	8,300	8,300	-	-	-	-	8,300	8,300	-

ATTACHMENT D.1(A)3-2: AVERAGE HEAT RATE - SHIFT PORTFOLIO

Average Heat Rate - B.1(f)(b) (Btu/kWh)																
UNIT	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Palo Verde																
Unit 1	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385
Unit 2	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361
Unit 3	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377
Four Corners																
Unit 4	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687				
Unit 5	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687				
Cholla																
Unit 1	10,818	10,631	10,519	10,551	10,671	11,523										
Unit 3	10,857	10,820	10,751	10,753	10,842	11,207										
Ocotillo																
Unit 1 CT	24,928	53,142	33,500	28,237	37,917	54,806	40,618	45,998	53,892	36,967	53,463	-	-	81,309	33,568	-
Unit 2 CT	23,007	47,466	29,191	29,054	33,772	53,428	38,233	40,781	53,592	31,566	49,557	-	28,097	-	80,755	84,214
Unit 3 CT	9,738	9,573	9,217	9,627	9,774	9,903	9,572	9,866	9,704	9,531	9,849	9,964	9,807	10,290	10,082	10,346
Unit 4 CT	9,650	9,491	9,251	9,388	9,763	9,880	9,460	9,578	9,662	9,384	9,708	9,936	9,798	10,205	9,775	10,220
Unit 5 CT	9,531	9,471	9,249	9,363	9,618	9,652	9,429	9,514	9,558	9,318	9,601	9,694	9,630	10,000	9,631	9,942
Unit 6 CT	9,669	9,636	9,231	9,563	9,821	9,819	9,518	9,861	9,719	9,539	9,796	9,865	9,811	10,190	9,943	10,232
Unit 7 CT	9,509	9,471	9,250	9,414	9,661	9,790	9,396	9,634	9,519	9,415	9,553	9,817	9,703	10,026	9,736	10,153
Saguaro																
Unit 1 CT	25,892	54,354	22,946	28,288	35,204	55,404	38,096	43,605	50,742	34,035	48,217	17,605	21,785	-	27,660	-
Unit 2 CT	29,713	50,432	21,274	28,960	38,223	54,417	34,449	38,768	48,072	33,977	45,650	-	18,441	-	18,441	-
Unit 3 CT	12,545	13,923	12,334	13,170	13,422	14,197	13,384	14,003	13,925	13,600	13,852	11,714	11,714	-	11,720	11,691
West Phoenix																
Unit 1 CC	9,879	10,504	9,356	9,407	10,263	11,694	9,725	10,405	11,524	9,651	10,792	9,316	10,698	11,218	11,481	12,326
Unit 2 CC	9,964	10,169	9,319	9,459	10,368	11,840	9,774	10,344	11,764	9,622	10,904	9,309	10,588	11,324	11,451	12,388
Unit 3 CC	9,541	9,740	9,259	9,329	9,652	10,348	9,635	9,862	10,118	9,423	9,761	9,320	9,376	9,328	9,331	9,318
Unit 4 CC	8,319	8,535	8,158	8,225	8,303	8,535	8,235	8,282	8,458	8,204	8,420	8,101	8,119	8,107	8,099	8,123
Unit 5 CC	7,582	7,645	7,524	7,556	7,555	7,625	7,521	7,521	7,644	7,478	7,579	7,516	7,571	7,607	7,608	7,646
Unit 1 CT	24,752	54,320	21,700	29,635	33,746	50,172	30,483	39,041	43,640	31,426	42,072	-	52,572	77,443	73,348	79,429
Unit 2 CT	26,068	58,251	22,473	32,436	35,797	51,923	30,625	39,556	45,709	32,821	43,151	-	60,049	80,418	75,404	79,142
Redhawk																
Unit 1 CC	7,061	7,095	7,027	6,976	7,052	7,056	7,007	6,967	7,180	6,964	7,099	6,937	6,967	6,980	6,990	6,980
Unit 2 CC	7,084	7,125	7,029	6,987	7,056	7,050	7,007	6,936	7,176	6,974	7,065	6,924	6,955	6,947	6,955	6,978
Sundance																
Unit 1 CT	10,543	10,701	10,478	10,653	10,124	10,860	9,977	10,087	10,174	10,258	10,091	11,364	10,694	11,509	11,039	11,226
Unit 2 CT	10,681	10,729	10,556	10,708	10,241	11,725	10,128	10,146	10,129	10,570	10,105	11,258	10,852	11,571	11,248	11,457
Unit 3 CT	10,751	10,786	10,662	10,807	10,485	11,064	10,125	10,827	10,213	10,167	10,156	11,368	10,945	11,528	10,919	11,408
Unit 4 CT	10,802	10,919	10,717	10,998	10,591	11,451	10,196	10,202	10,105	10,599	10,206	11,631	10,970	11,669	11,148	11,109
Unit 5 CT	10,875	10,992	10,740	10,998	10,639	11,158	10,233	10,630	10,096	10,340	10,326	11,200	10,926	11,135	11,152	11,634
Unit 6 CT	10,853	11,240	10,902	11,088	10,670	11,394	10,184	10,778	10,098	9,977	10,286	11,549	10,910	11,544	11,043	11,399
Unit 7 CT	10,495	10,659	10,382	10,428	10,125	10,527	9,994	9,974	10,160	10,403	9,998	11,261	10,875	11,188	11,054	11,308
Unit 8 CT	10,802	11,000	10,814	11,015	10,774	11,374	10,250	10,702	10,135	9,941	10,263	11,475	10,835	11,389	10,939	11,061
Unit 9 CT	10,599	10,743	10,514	10,532	10,232	10,807	10,056	10,292	10,165	10,526	10,119	11,462	10,921	11,388	11,210	11,423
Unit 10 CT	10,633	10,689	10,502	10,794	10,172	11,295	10,122	10,419	10,185	10,670	10,124	11,343	10,921	11,695	11,218	11,142
Yucca																
Unit 1 CT	24,088	42,870	22,570	31,278	30,886	47,311	29,601	41,785	37,497	36,327	36,648	64,992	35,081	64,894	43,184	58,854
Unit 2 CT	24,846	44,986	22,433	28,137	31,265	47,128	30,066	42,035	38,037	35,353	36,595	19,044	32,330	63,107	50,959	60,771
Unit 3 CT	15,154	33,938	17,384	22,105	22,445	39,274	24,194	37,083	32,168	28,930	31,404	55,020	30,110	57,758	50,801	55,898
Unit 4 CT	62,439	63,068	65,444	65,979	64,472	62,347	65,874	65,012	61,574	61,476	63,589	-	-	-	-	-
Unit 5 CT	10,455	10,520	10,487	10,897	10,694	11,370	10,009	10,451	10,127	10,614	9,986	11,389	10,761	11,540	11,166	11,508
Unit 6 CT	10,535	10,618	10,619	11,039	10,782	11,055	9,986	10,528	10,050	10,746	10,045	11,231	10,709	11,569	11,106	11,902

ATTACHMENT D.1(A)3-2: AVERAGE HEAT RATE - SHIFT PORTFOLIO (CONTINUED)

Average Heat Rate - B.1(f)(b) (Btu/kWh)																
UNIT	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Douglas																
Unit 1 CT	54,029	56,407	55,172	58,348	57,762	53,568	58,317	54,593	58,817	57,157	57,616	55,982	-	59,125	-	57,577
Mircrogrids																
Aligned	8,300	8,300	8,300	-	8,300	-	8,300	-	8,300	-	-	-	-	-	-	-
MCASY	8,300	8,300	8,300	-	8,300	8,300	8,300	8,300	8,300	8,300	-	-	8,300	8,300	8,300	8,300
Future Units																
Future Microgrids	-	8,300	8,300	-	8,300	8,300	8,300	8,300	8,300	-	-	-	8,300	8,300	-	8,300

ATTACHMENT D.1(A)3-3: AVERAGE HEAT RATE - ACCELERATE PORTFOLIO

Average Heat Rate - B.1(f)(b) (Btu/kWh)																
UNIT	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Palo Verde																
Unit 1	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385	10,385
Unit 2	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361	10,361
Unit 3	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377	10,377
Four Corners																
Unit 4	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687				
Unit 5	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687	9,687				
Cholla																
Unit 1	10,813	10,624	10,518	10,531	10,633	11,559										
Unit 3	10,850	10,817	10,762	10,743	10,824	11,199										
Ocotillo																
Unit 1 CT	24,925	53,701	32,561	27,006	39,407	53,456	33,362	33,208	44,045	25,382	43,939	-	18,441	18,441	47,164	18,441
Unit 2 CT	22,901	48,244	29,969	28,558	35,610	50,123	37,239	29,587	41,631	24,696	42,750	-	54,598	19,071	15,635	16,781
Unit 3 CT	9,771	9,614	9,286	9,556	9,823	9,836	9,494	9,479	9,354	9,461	9,710	9,636	9,710	10,094	10,169	10,296
Unit 4 CT	9,667	9,509	9,251	9,365	9,799	9,787	9,377	9,385	9,353	9,423	9,640	9,538	9,518	9,900	9,920	10,157
Unit 5 CT	9,523	9,437	9,235	9,350	9,676	9,694	9,303	9,320	9,305	9,320	9,609	9,458	9,510	9,657	9,727	9,824
Unit 6 CT	9,694	9,664	9,263	9,519	9,927	9,887	9,404	9,435	9,405	9,375	9,712	9,570	9,604	9,877	10,049	10,151
Unit 7 CT	9,528	9,495	9,237	9,389	9,787	9,828	9,340	9,336	9,310	9,371	9,527	9,537	9,466	9,752	9,779	9,987
Saguaro																
Unit 1 CT	26,655	55,597	22,330	27,918	38,255	52,747	34,969	32,384	39,313	26,153	41,770	-	18,441	18,441	18,441	18,441
Unit 2 CT	30,336	54,987	21,044	30,664	39,285	51,313	31,965	27,298	36,958	25,883	40,524	-	18,441	18,441	18,441	33,887
Unit 3 CT	12,505	13,932	12,485	13,202	13,458	14,170	13,340	13,522	13,623	12,958	13,726	11,691	11,714	11,681	11,690	11,697
West Phoenix																
Unit 1 CC	9,916	10,593	9,384	9,417	10,323	11,770	9,876	10,091	11,070	9,554	11,183	9,864	11,686	12,758	13,292	13,979
Unit 2 CC	9,978	10,226	9,329	9,448	10,494	11,689	9,958	9,915	11,254	9,650	11,524	9,469	11,438	12,639	12,634	14,122
Unit 3 CC	9,563	9,758	9,262	9,323	9,708	10,387	9,591	9,573	9,949	9,389	9,735	9,312	9,435	9,266	9,279	9,358
Unit 4 CC	8,323	8,547	8,157	8,228	8,326	8,556	8,191	8,149	8,447	8,170	8,476	8,096	8,111	8,113	8,115	8,119
Unit 5 CC	7,581	7,649	7,527	7,554	7,582	7,637	7,508	7,471	7,632	7,456	7,630	7,509	7,560	7,586	7,598	7,630
Unit 1 CT	25,187	55,836	22,545	28,920	34,669	48,107	27,616	28,589	35,815	23,227	36,896	80,755	77,894	72,735	75,827	69,427
Unit 2 CT	26,276	58,104	22,759	32,124	36,966	48,858	28,784	31,289	36,700	23,833	37,817	80,755	77,538	77,978	77,375	77,475
Redhawk																
Unit 1 CC	7,058	7,100	7,024	6,976	7,055	7,064	6,995	6,970	7,241	6,968	7,270	6,941	6,976	6,972	7,005	6,989
Unit 2 CC	7,080	7,126	7,025	6,981	7,041	7,062	6,990	6,930	7,270	6,963	7,245	6,954	6,987	6,977	6,975	7,007
Sundance																
Unit 1 CT	10,493	10,659	10,421	10,451	10,166	11,178	10,073	10,431	9,965	10,212	9,982	10,948	11,063	11,121	10,900	10,551
Unit 2 CT	10,646	10,892	10,600	10,879	10,239	11,293	10,100	10,369	10,025	10,319	10,041	11,103	11,266	11,601	11,301	10,862
Unit 3 CT	10,717	10,906	10,627	10,879	10,616	11,129	10,094	10,582	9,990	10,330	9,978	10,951	11,200	11,545	11,346	11,061
Unit 4 CT	10,729	10,947	10,707	10,994	10,581	11,395	10,159	10,252	10,030	10,253	10,006	10,938	11,144	11,400	11,155	11,286
Unit 5 CT	10,818	11,018	10,818	10,790	10,589	11,185	10,139	10,425	10,012	10,242	10,069	11,093	11,111	11,306	11,392	10,936
Unit 6 CT	10,862	11,242	10,917	11,060	10,595	11,450	10,127	10,565	10,017	10,278	10,050	10,967	11,187	11,436	11,347	11,060
Unit 7 CT	10,468	10,643	10,355	10,373	10,096	10,429	10,018	10,215	9,972	10,176	9,992	10,958	11,066	11,259	11,050	10,585
Unit 8 CT	10,798	10,965	10,721	10,944	10,622	10,897	10,165	10,511	10,012	10,287	10,032	11,092	11,124	11,622	11,263	11,338
Unit 9 CT	10,600	10,730	10,486	10,478	10,241	11,017	10,122	10,178	10,025	10,236	10,043	10,999	11,092	11,320	11,095	10,874
Unit 10 CT	10,599	10,774	10,467	10,754	10,179	11,423	10,107	10,248	9,964	10,230	9,983	10,956	11,175	11,240	11,035	10,708
Yucca																
Unit 1 CT	24,979	44,045	22,894	29,511	32,359	45,798	28,274	29,920	31,691	24,944	32,638	63,014	55,922	61,917	58,875	50,907
Unit 2 CT	25,869	45,319	23,166	29,468	32,689	45,827	28,828	29,744	31,330	24,923	32,009	64,227	48,907	56,469	58,261	58,043
Unit 3 CT	15,113	34,709	18,494	21,308	22,162	37,593	22,495	23,723	25,815	21,334	27,508	57,529	53,548	55,443	55,285	56,057
Unit 4 CT	62,497	63,076	65,198	65,917	64,590	62,365	66,001	65,123	62,109	64,824	62,506	-	-	66,020	66,020	66,020
Unit 5 CT	10,421	10,529	10,529	10,853	10,758	11,382	9,959	10,292	9,889	10,274	9,927	11,087	11,054	11,798	11,339	11,404
Unit 6 CT	10,587	10,731	10,650	11,118	10,807	11,172	9,966	10,227	9,903	10,238	9,933	10,864	10,868	11,788	11,433	11,341

ATTACHMENT D.1(A)3-3: AVERAGE HEAT RATE - ACCELERATE PORTFOLIO (CONTINUED)

Average Heat Rate - B.1(f)(b) (Btu/kWh)																
UNIT	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Douglas																
Unit 1 CT	55,033	58,032	58,614	54,563	56,909	53,029	59,125	57,697	58,976	57,719	58,851	-	59,125	59,125	59,125	59,125
Mircrogrids																
Aligned	8,300	-	8,300	-	-	-	8,300	-	-	-	-	-	8,300	8,300	8,300	8,300
MCASY	8,300	-	8,300	-	8,300	8,300	8,300	8,300	-	-	8,300	-	8,300	8,300	8,300	8,300
Future Units																
Future Microgrids	-	-	8,300	-	-	8,300	8,300	-	-	-	-	-	8,300	8,300	8,300	8,300

ATTACHMENT D.1(A)(4): AVERAGE FUEL COST

Average Fuel Cost - B.1 ($/MMBtu)																
FUEL	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Uranium	[redacted]															
Coal - Four Corners	[redacted]															
Coal - Cholla	[redacted]															
Gas	[redacted]															

ATTACHMENT D.1(A)(5)-1: PURCHASED POWER ENERGY COSTS FOR LONG-TERM CONTRACTS - BRIDGE PORTFOLIO

Energy Cost for Long Term Contract B.1(i) ($/MWh)																
UNIT	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Renewables																
Aragonne Mesa Wind, New Mexico	[redacted]															
Salton Sea CE Turbo #1	[redacted]															
SWMP Biomass (Snowflake Abitibi)	[redacted]															
High Lonesome Wind, New Mexico	[redacted]															
Perrin Ranch Wind	[redacted]															
Solana CSP	[redacted]															
Small Gen RFP (Ajo)	[redacted]															
Small Gen RFP (Prescott)	[redacted]															
Small Gen RFP (Saddle Mt Tonopah)	[redacted]															
Small Gen RFP (WM Landfill)	[redacted]															
Badger-Desert Sky	[redacted]															
Recurrent Gillespie	[redacted]															
Bagdad	[redacted]															
New Wind 2	[redacted]															
New Wind 5	[redacted]															
Contracts																
[redacted]																
CC Tolling # 1	[redacted]															
CC Tolling # 2	[redacted]															
CC Tolling # 3	[redacted]															
Future CC Tolling #1	[redacted]															
Future CC Tolling #2	[redacted]															
AGX Load	[redacted]															
Solar + Storage System PPA 1	[redacted]															

Notes
(1) Based on Palo Verde Day-Ahead Index

ATTACHMENT D.1(A)(5)-2: PURCHASED POWER ENERGY COSTS FOR LONG-TERM CONTRACTS - SHIFT PORTFOLIO

Energy Cost for Long Term Contract B.1(i) ($/MWh)																
UNIT	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Renewables																
Aragonne Mesa Wind, New Mexico	[redacted]															
Salton Sea CE Turbo #1	[redacted]															
SWMP Biomass (Snowflake Abitibi)	[redacted]															
High Lonesome Wind, New Mexico	[redacted]															
Perrin Ranch Wind	[redacted]															
Solana CSP	[redacted]															
Small Gen RFP (Ajo)	[redacted]															
Small Gen RFP (Prescott)	[redacted]															
Small Gen RFP (Saddle Mt Tonopah)	[redacted]															
Small Gen RFP (WM Landfill)	[redacted]															
Badger-Desert Sky	[redacted]															
Recurrent Gillespie	[redacted]															
Bagdad	[redacted]															
New Wind 2	[redacted]															
New Wind 5	[redacted]															
Contracts																
[redacted]	[redacted]															
CC Tolling # 1	[redacted]															
CC Tolling # 2	[redacted]															
CC Tolling # 3	[redacted]															
Future CC Tolling #1	[redacted]															
Future CC Tolling #2	[redacted]															
AGX Load	[redacted]															
Solar + Storage System PPA 1	[redacted]															

Notes
(1) Based on Palo Verde Day-Ahead Index

ATTACHMENT D.1(A)(5)-3: PURCHASED POWER ENERGY COSTS FOR LONG-TERM CONTRACTS - ACCELERATE PORTFOLIO

Energy Cost for Long Term Contract B.1(i) ($/MWh)																
UNIT	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Renewables																
Aragonne Mesa Wind, New Mexico	[redacted]															
Salton Sea CE Turbo #1	[redacted]															
SWMP Biomass (Snowflake Abitibi)	[redacted]															
High Lonesome Wind, New Mexico	[redacted]															
Perrin Ranch Wind	[redacted]															
Solana CSP	[redacted]															
Small Gen RFP (Ajo)	[redacted]															
Small Gen RFP (Prescott)	[redacted]															
Small Gen RFP (Saddle Mt Tonopah)	[redacted]															
Small Gen RFP (WM Landfill)	[redacted]															
Badger-Desert Sky	[redacted]															
Recurrent Gillespie	[redacted]															
Bagdad	[redacted]															
New Wind 2	[redacted]															
New Wind 5	[redacted]															
Future Biomass	[redacted]															
Contracts																
[redacted]																
CC Tolling # 1	[redacted]															
CC Tolling # 2	[redacted]															
CC Tolling # 3	[redacted]															
Future CC Tolling #1	[redacted]															
Future CC Tolling #2	[redacted]															
AGX Load	[redacted]															
Solar + Storage System PPA 1	[redacted]															

Notes
(1) Based on Palo Verde Day-Ahead Index

ATTACHMENT D.1(A)(6): FIXED O&M

Fixed Operating and Maintenance - B.1(j) ($/MW)																
PLANT	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Palo Verde	[redacted]															
Cholla	[redacted]															
Four Corners	[redacted]															
Ocotillo	[redacted]															
Douglas	[redacted]															
Saguaro	[redacted]															
Sundance	[redacted]															
Redhawk	[redacted]															
West Phoenix	[redacted]															
Yucca	[redacted]															
AZ Sun: Hyder II	[redacted]															
AZ Sun: Cotton Center	[redacted]															
AZ Sun: Hyder I	[redacted]															
AZ Sun: Chino Valley	[redacted]															
AZ Sun: Paloma	[redacted]															
AZ Sun: Yuma Foothills	[redacted]															
AZ Sun: Gila Bend	[redacted]															
AZ Sun: Luke	[redacted]															
AZ Sun: Desert Star	[redacted]															
Red Rock Solar	[redacted]															

Fixed Operating and Maintenance - B.1(j) ($/MW)																
PLANT	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Future Units: Bridge Portfolio																
Future CT 1	[redacted]															
Future CT 2	[redacted]															
Furture Microgrids	[redacted]															
Solar + Storage System 1	[redacted]															
Solar + Storage System 2	[redacted]															
Solar + Storage System 3	[redacted]															
Solar + Storage System 4	[redacted]															
Solar + Storage System 5	[redacted]															
Solar + Storage System 6	[redacted]															
Solar + Storage System 7	[redacted]															
Solar + Storage System 8	[redacted]															
Solar + Storage System 9	[redacted]															
Solar + Storage System 10	[redacted]															
Solar + Storage System 11	[redacted]															
Solar + Storage System 12	[redacted]															
Solar + Storage System 13	[redacted]															
Energy Storage System 1	[redacted]															
Energy Storage System 2	[redacted]															
New Wind	[redacted]															

ATTACHMENT D.1(A)(6): FIXED O&M (CONTINUED)

Fixed Operating and Maintenance - B.1(j) ($/MW)																
PLANT	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Future Units: Shift Portfolio																
Furture Microgrids	[redacted]															
Solar + Storage System 1	[redacted]															
Solar + Storage System 2	[redacted]															
Solar + Storage System 3	[redacted]															
Solar + Storage System 4	[redacted]															
Solar + Storage System 5	[redacted]															
Solar + Storage System 6	[redacted]															
Solar + Storage System 7	[redacted]															
Solar + Storage System 8	[redacted]															
Solar + Storage System 9	[redacted]															
Solar + Storage System 10	[redacted]															
Solar + Storage System 11	[redacted]															
Solar + Storage System 12	[redacted]															
Solar + Storage System 13	[redacted]															
Energy Storage System 1	[redacted]															
Energy Storage System 2	[redacted]															
New Wind	[redacted]															

ATTACHMENT D.1(A)(6): FIXED O&M (CONTINUED)

Fixed Operating and Maintenance - B.1(j) ($/MW)																
PLANT	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Future Units: Accelerate Portfolio																
Furture Microgrid	[redacted]															
Solar + Storage System 1																
Solar + Storage System 2																
Solar + Storage System 3																
Solar + Storage System 4																
Solar + Storage System 5																
Solar + Storage System 6																
Solar + Storage System 7																
Solar + Storage System 8																
Solar + Storage System 9																
Solar + Storage System 10																
Solar + Storage System 11																
Solar + Storage System 12																
Solar + Storage System 13																
Energy Storage System 1																
Energy Storage System 2																
Energy Storage System 3																
Energy Storage System 4																
Energy Storage System 5																
Energy Storage System 6																
Energy Storage System 7																
New Wind																

ATTACHMENT D.1(A)(7)-1: DEMAND CHARGES FOR PURCHASE POWER - BRIDGE PORTFOLIO

Demand Charges for Purchased Power - B.1(k) ($/kW-Yr)																
Contract	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy Storage System PPA 1	[redacted]															
Energy Storage System PPA 2																
CC Tolling # 1																
CC Tolling # 2																
CC Tolling # 3																
Future CC Tolling #1																
Future CC Tolling #2																

[redacted]

ATTACHMENT D.1(A)(7)-2: DEMAND CHARGES FOR PURCHASE POWER - SHIFT PORTFOLIO

Demand Charges for Purchased Power - B.1(k) ($/kW-Yr)																
Contract	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy Storage System PPA 1	[redacted]															
Energy Storage System PPA 2																
CC Tolling # 1																
CC Tolling # 2																
CC Tolling # 3																
Future CC Tolling #1																
Future CC Tolling #2																

[redacted]

ATTACHMENT D.1(A)(7)-3: DEMAND CHARGES FOR PURCHASE POWER - ACCELERATE PORTFOLIO

Demand Charges for Purchased Power - B.1(k) ($/kW-Yr)																
Contract	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy Storage System PPA 1	[redacted]															
Energy Storage System PPA 2																
CC Tolling # 1																
CC Tolling # 2																
CC Tolling # 3																

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Unit 1 CT																	
Unit 2 CT																	
TOTAL		**11,141,601**	**11,693,956**	**11,416,682**	**11,241,797**	**11,635,912**	**10,502,108**	**9,979,427**	**9,777,875**	**10,438,139**	**9,621,645**	**9,798,438**	**7,264,548**	**5,859,708**	**5,537,823**	**5,509,549**	**5,087,241**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5																	
Cholla																	
Unit 1	[redacted]																
Unit 3																	
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT	[redacted]																

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
	[redacted]																
Un t 1 CT	[redacted]																
Un t 2 CT	[redacted]																
TOTAL		**1,307**	**1,355**	**1,249**	**1,239**	**1,336**	**1,267**	**1,084**	**1,075**	**1,250**	**1,034**	**1,122**	**671**	**475**	**448**	**451**	**421**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT	[redacted]																

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Un t 1 CT																	
Un t 2 CT																	
TOTAL		**55**	**59**	**55**	**52**	**58**	**55**	**52**	**50**	**57**	**46**	**50**	**44**	**47**	**43**	**43**	**40**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Un t 1 CT																	
Un t 2 CT																	
TOTAL		**5,543**	**5,646**	**5,238**	**5,128**	**5,616**	**4,870**	**3,877**	**3,808**	**4,858**	**3,804**	**4,269**	**1,990**	**966**	**891**	**952**	**902**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-1: ENVIRONMENTAL IMPACTS - BRIDGE PORTFOLIO (CONTINUED)

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT	[redacted]																

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
	[redacted]																
Un t 1 CT	[redacted]																
Un t 2 CT	[redacted]																
TOTAL		**1,508**	**1,540**	**1,574**	**1,561**	**1,590**	**1,094**	**943**	**914**	**960**	**926**	**905**	**426**	**31**	**29**	**29**	**27**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-1: ENVIRONMENTAL IMPACTS - BRIDGE PORTFOLIO (CONTINUED)

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8)-1: ENVIRONMENTAL IMPACTS - BRIDGE PORTFOLIO (CONTINUED)

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
TOTAL		**0.0210**	**0.0225**	**0.0217**	**0.0213**	**0.0222**	**0.0185**	**0.0168**	**0.0165**	**0.0181**	**0.0160**	**0.0166**	**0.0141**	**0.0138**	**0.0131**	**0.0130**	**0.0120**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5																	
Cholla																	
Unit 1	[redacted]																
Unit 3																	
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT	[redacted]																

ATTACHMENT D.1(A)(8)-1: ENVIRONMENTAL IMPACTS - BRIDGE PORTFOLIO (CONTINUED)

PM10 Emissions – B.1(p) (Tons)																	
UNIT	**Rate[1] (lb/ MM Btu)**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Un t 1 CT																	
Un t 2 CT																	
TOTAL		**471**	**486**	**465**	**453**	**472**	**401**	**363**	**354**	**392**	**350**	**366**	**261**	**210**	**194**	**195**	**178**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-1: ENVIRONMENTAL IMPACTS - BRIDGE PORTFOLIO (CONTINUED)

Water Consumption – B.1(q) (Acre-Feet)																	
UNIT	Rate[1] (Gal/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
PaloVerde 1,2,3	[redacted]																
Cholla 1,3 [2]																	
Four Corners 4,5																	
Ocotillo CTs 1-7																	
Redhawk 1,2																	
Saguaro CTs 1,2,3																	
Sundance CTs 1-10																	
West Phoenix CCs 1-5, CTs 1,2																	
Yucca CTs 1-6																	
Douglas																	
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Other Purchases[3]																	
Salton Sea Geothermal																	
Snowflake B omass																	
NW Reg onal Landfill																	
Solana																	

ATTACHMENT D.1(A)(8)-1: ENVIRONMENTAL IMPACTS - BRIDGE PORTFOLIO (CONTINUED)

Water Consumption – B.1(q) (Acre-Feet)

UNIT	Rate[1] (Gal/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Unit 1 CT																	
Unit 2 CT																	
Future Biomass																	
TOTAL		**49,545**	**52,493**	**52,130**	**52,008**	**52,260**	**48,083**	**46,634**	**46,495**	**46,734**	**45,727**	**45,154**	**40,524**	**37,521**	**37,053**	**36,698**	**35,969**

Notes:

(1) Water rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-1: ENVIRONMENTAL IMPACTS - BRIDGE PORTFOLIO (CONTINUED)

Coal Ash Bottom Collected - B.1 (r) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4																	
Unit 5																	
Cholla																	
Unit 1																	
Unit 3																	
TOTAL		**118,979**	**122,151**	**122,328**	**122,523**	**122,625**	**109,318**	**103,195**	**101,489**	**101,917**	**101,634**	**101,204**	**45,559**	**0**	**0**	**0**	**0**

Notes:

(1) Rates are based on 2020 estimates.

Coal Fly Ash Collected – B.1(r) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
TOTAL		**503,166**	**519,378**	**520,140**	**520,977**	**521,422**	**445,393**	**412,779**	**405,957**	**407,666**	**406,535**	**404,818**	**182,237**	**0**	**0**	**0**	**0**

Notes:

(1) Rates are based on 2020 estimates.

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases2																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Unit 1 CT																	
Unit 2 CT																	
TOTAL		11,135,430	11,671,846	11,415,980	11,244,912	11,634,389	10,517,524	9,978,570	9,714,361	10,094,167	9,236,856	9,691,819	6,508,295	4,916,147	4,524,933	4,345,778	3,839,000

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Un t 1 CT																	
Un t 2 CT																	
TOTAL		**1,310**	**1,349**	**1,248**	**1,242**	**1,336**	**1,273**	**1,080**	**1,067**	**1,258**	**1,021**	**1,178**	**632**	**422**	**388**	**379**	**342**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted] market.

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Un t 1 CT																	
Un t 2 CT																	
TOTAL		**55**	**58**	**56**	**52**	**57**	**55**	**52**	**50**	**54**	**42**	**50**	**36**	**38**	**34**	**33**	**29**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted] market.

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5																	
Cholla																	
Unit 1	[redacted]																
Unit 3																	
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
	[redacted]																
Un t 1 CT	[redacted]																
Un t 2 CT	[redacted]																
TOTAL		**5,521**	**5,620**	**5,218**	**5,139**	**5,599**	**4,883**	**3,853**	**3,773**	**4,964**	**3,819**	**4,573**	**1,969**	**989**	**908**	**931**	**906**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

SO2 Emissions – B.1(p) (Tons)																	
UNIT	**Rate[1] (lb/ MM Btu)**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Un t 1 CT																	
Un t 2 CT																	
TOTAL		**1,508**	**1,539**	**1,573**	**1,561**	**1,589**	**1,095**	**943**	**914**	**960**	**926**	**906**	**423**	**27**	**25**	**24**	**21**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Unit 1 CT																	
Unit 2 CT																	
TOTAL		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4																	
Unit 5																	
Cholla																	
Unit 1																	
Unit 3																	
Ocotillo																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC																	
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	

PM10 Emissions – B.1(p) (Tons)																	
UNIT	**Rate[1] (lb/ MM Btu)**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
	[redacted]																
Un t 1 CT	[redacted]																
Un t 2 CT	[redacted]																
TOTAL		**471**	**486**	**465**	**453**	**471**	**402**	**363**	**352**	**386**	**342**	**372**	**241**	**186**	**166**	**162**	**142**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

Water Consumption – B.1(q) (Acre-Feet)																	
UNIT	Rate[1] (Gal/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
PaloVerde 1,2,3																	
Cholla 1,3 [2]																	
Four Corners 4,5																	
Ocotillo CTs 1-7																	
Redhawk 1,2																	
Saguaro CTs 1,2,3																	
Sundance CTs 1-10																	
West Phoenix CCs 1-5, CTs 1,2																	
Yucca CTs 1-6																	
Douglas																	
Tolling Agreements & Purchases																	
CC Tolling #1																	
CC Tolling #2																	
CC Tolling #3																	
Other Purchases[3]																	
Salton Sea Geothermal																	
Snowflake B omass																	
NW Reg onal Landfill																	
Solana																	

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

Water Consumption – B.1(q) (Acre-Feet)																	
UNIT	Rate[1] (Gal/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Unit 1 CT																	
Unit 2 CT																	
Future Biomass																	
TOTAL		**49,519**	**52,459**	**52,133**	**52,004**	**52,273**	**48,104**	**46,652**	**46,370**	**46,246**	**45,305**	**45,179**	**39,559**	**36,067**	**35,365**	**34,671**	**33,643**

Notes:

(1) Water rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

Coal Ash Bottom Collected – B.1(r) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4																	
Unit 5																	
Cholla																	
Unit 1																	
Unit 3																	
TOTAL		**118,983**	**122,159**	**122,342**	**122,523**	**122,636**	**109,298**	**103,196**	**101,487**	**101,914**	**101,643**	**101,245**	**45,556**	**0**	**0**	**0**	**0**

Notes:

(1) Rates are based on 2020 estimates.

ATTACHMENT D.1(A)(8)-2: ENVIRONMENTAL IMPACTS - SHIFT PORTFOLIO (CONTINUED)

Coal Fly Ash Collected – B.1(r) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4																	
Unit 5																	
Cholla																	
Unit 1																	
Unit 3																	
TOTAL		**503,194**	**519,425**	**520,221**	**520,980**	**521,482**	**445,276**	**412,783**	**405,946**	**407,656**	**406,574**	**404,978**	**182,223**	**0**	**0**	**0**	**0**

Notes:

(1) Rates are based on 2020 estimates.

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

CO2 Emissions – B.1(p) (Metric Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Unit 1 CT																	
Unit 2 CT																	
TOTAL		11,137,404	11,686,937	11,419,284	11,190,923	11,570,915	10,549,531	9,556,528	9,075,484	9,369,928	8,053,675	8,945,773	5,288,680	3,363,127	2,934,025	2,688,898	2,333,962

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Unit 8 CT	[redacted]																
Unit 9 CT	[redacted]																
Unit 10 CT	[redacted]																
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Douglas																	
Unit 1 CT	[redacted]																

CO Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
	[redacted]																
Un t 1 CT	[redacted]																
Un t 2 CT	[redacted]																
TOTAL		**1,308**	**1,353**	**1,250**	**1,235**	**1,329**	**1,276**	**1,074**	**1,029**	**1,242**	**962**	**1,191**	**525**	**296**	**267**	**250**	**230**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5																	
Cholla																	
Unit 1	[redacted]																
Unit 3																	
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Unit 3 CC																	
Unit 4 CC																	
Unit 5 CC																	
Unit 1 CT																	
Unit 2 CT																	

VOC Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	

VOC Emissions – B.1(p) (Tons)

UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
	[redacted]																
Un t 1 CT	[redacted]																
Un t 2 CT	[redacted]																
TOTAL		**55**	**58**	**56**	**52**	**57**	**55**	**49**	**47**	**51**	**34**	**46**	**27**	**27**	**22**	**20**	**18**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT	[redacted]																

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

NOX Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Un t 1 CT																	
Un t 2 CT																	
TOTAL		**5,535**	**5,635**	**5,237**	**5,117**	**5,591**	**4,891**	**3,991**	**3,937**	**5,235**	**3,932**	**4,994**	**1,917**	**1,087**	**996**	**1,000**	**978**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	

SO2 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
	[redacted]																
Un t 1 CT	[redacted]																
Un t 2 CT	[redacted]																
TOTAL		**1,508**	**1,539**	**1,573**	**1,562**	**1,590**	**1,095**	**942**	**910**	**956**	**917**	**905**	**416**	**19**	**16**	**15**	**13**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC																	
Unit 2 CC																	
Sundance																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT																	
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT																	

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

HG Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
CC Tolling #3																	
Short Term Purchase																	
Other Purchases[2]																	
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Unit 1 CT																	
Unit 2 CT																	
TOTAL		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4	[redacted]																
Unit 5	[redacted]																
Cholla																	
Unit 1	[redacted]																
Unit 3	[redacted]																
Ocotillo																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
Unit 4 CT	[redacted]																
Unit 5 CT	[redacted]																
Unit 6 CT	[redacted]																
Unit 7 CT	[redacted]																
Saguaro																	
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																
Unit 3 CT	[redacted]																
West Phoenix																	
Unit 1 CC	[redacted]																
Unit 2 CC	[redacted]																
Unit 3 CC	[redacted]																
Unit 4 CC	[redacted]																
Unit 5 CC	[redacted]																
Unit 1 CT	[redacted]																
Unit 2 CT	[redacted]																

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Redhawk																	
Unit 1 CC	[redacted]																
Unit 2 CC																	
Sundance																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Unit 7 CT																	
Unit 8 CT																	
Unit 9 CT																	
Unit 10 CT																	
Yucca																	
Unit 1 CT	[redacted]																
Unit 2 CT																	
Unit 3 CT																	
Unit 4 CT																	
Unit 5 CT																	
Unit 6 CT																	
Douglas																	
Unit 1 CT	[redacted]																

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

PM10 Emissions – B.1(p) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Short Term Purchase	[redacted]																
	[redacted]																
Other Purchases[2]	[redacted]																
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
	[redacted]																
Un t 1 CT	[redacted]																
Un t 2 CT	[redacted]																
TOTAL		**471**	**486**	**466**	**451**	**469**	**403**	**345**	**337**	**374**	**310**	**359**	**205**	**138**	**118**	**108**	**94**

Notes:

(1) Emissions rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

Water Consumption – B.1(q) (Acre-Feet)																	
UNIT	Rate[1] (Gal/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
PaloVerde 1,2,3	[redacted]																
Cholla 1,3 [2]	[redacted]																
Four Corners 4,5	[redacted]																
Ocotillo CTs 1-7	[redacted]																
Redhawk 1,2	[redacted]																
Saguaro CTs 1,2,3	[redacted]																
Sundance CTs 1-10	[redacted]																
West Phoenix CCs 1-5, CTs	[redacted]																
Yucca CTs 1-6	[redacted]																
Douglas	[redacted]																
Tolling Agreements & Purchases																	
CC Tolling #1	[redacted]																
CC Tolling #2	[redacted]																
CC Tolling #3	[redacted]																
	[redacted]																
Other Purchases[3]	[redacted]																
	[redacted]																
Salton Sea Geothermal	[redacted]																
Snowflake Biomass	[redacted]																
NW Reg onal Landfill	[redacted]																
Solana	[redacted]																

Water Consumption – B.1(q) (Acre-Feet)																	
UNIT	Rate[1] (Gal/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Future Units																	
CC Tolling #1	[redacted]																
CC Tolling #2																	
Unit 1 CT																	
Unit 2 CT																	
Future Biomass																	
TOTAL		**49,520**	**52,485**	**52,127**	**52,136**	**52,518**	**48,583**	**45,846**	**44,916**	**44,463**	**42,475**	**43,135**	**36,783**	**32,489**	**31,699**	**30,922**	**30,241**

Notes:

(1) Water rates are based on 2020 estimates.

[redacted]

ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

Coal Ash Bottom Collected – B.1(r) (Tons)																	
UNIT	Rate[1] (lb/ MM Btu)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Four Corners																	
Unit 4																	
Unit 5																	
Cholla																	
Unit 1																	
Unit 3																	
TOTAL		**118,979**	**122,159**	**122,335**	**122,512**	**122,619**	**109,303**	**103,206**	**101,485**	**101,910**	**101,597**	**101,259**	**45,552**	**0**	**0**	**0**	**0**

Notes:

(1) Rates are based on 2020 estimates.

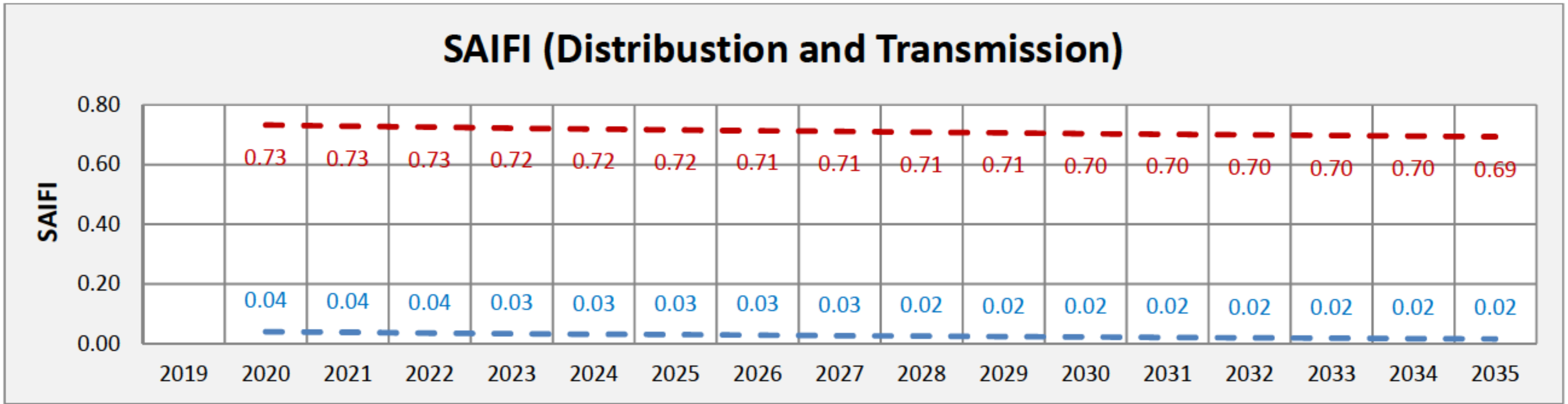
ATTACHMENT D.1(A)(8)-3: ENVIRONMENTAL IMPACTS - ACCELERATE PORTFOLIO (CONTINUED)

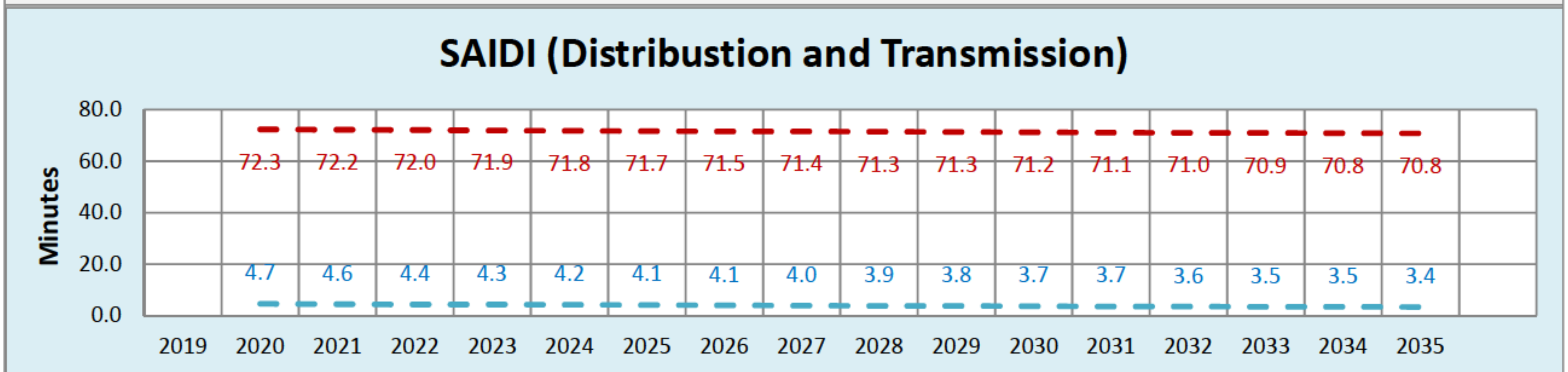
Coal Fly Ash Collected – B.1(r) (Tons)																	
UNIT	**Rate[1] (lb/ MM Btu)**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Four Corners																	
Unit 4																	
Unit 5																	
Cholla																	
Unit 1																	
Unit 3																	
TOTAL		**503,168**	**519,423**	**520,179**	**520,916**	**521,385**	**445,302**	**412,824**	**405,940**	**407,638**	**406,390**	**405,037**	**182,206**	**0**	**0**	**0**	**0**

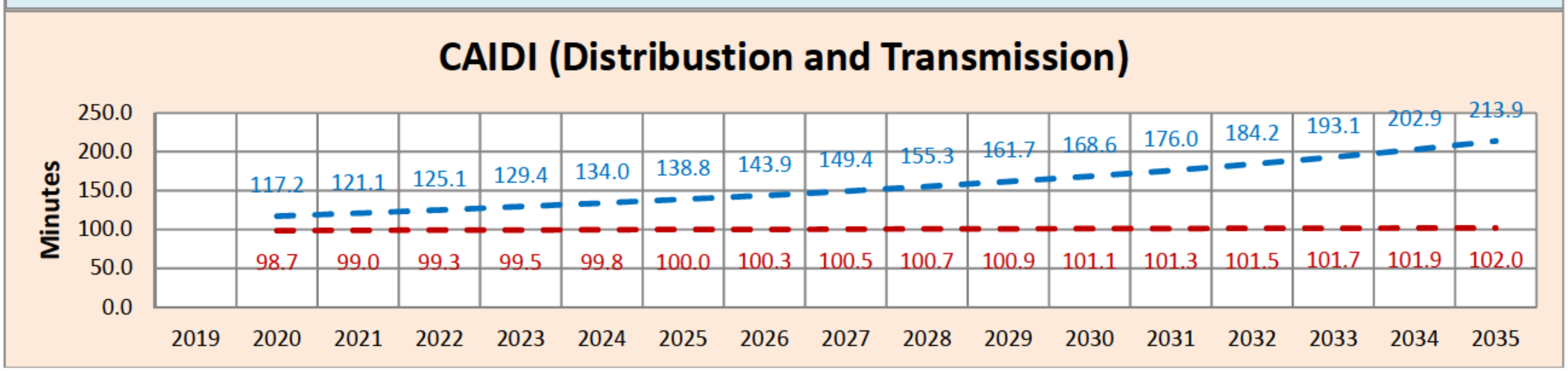
Notes:

(1) Rates are based on 2020 estimates.

ATTACHMENT D.1(B): TRANSMISSION & DISTRIBUTION RELIABILITY







ATTACHMENT D.1(C)-1: CAPITAL COST AND CONSTRUCTION SPENDING SCHEDULE - BRIDGE PORTFOLIO

Bridge Portfolio - Capital Costs
Generation Construction Cash Flow without AFUDC
in Millions of Dollars

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Capital Costs through 2035 TOTAL
1 Peaking Generation																		
1	Future CT 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Future CT 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Solar + Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2 Energy Storage and Microgrid Systems																		
1	Energy Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Energy Storage System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Microgrid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Microgrid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Microgrid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Microgrid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1	Microgrid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3 Renewables																		
	New Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	New Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	New Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	New Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	New Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	New Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	New Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	New Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	New Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4 Grand Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5 Cumulative Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Shift Portfolio - Capital Costs
Generation Construction Cash Flow without AFUDC
in Millions of Dollars

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Capital Costs through 2035 TOTAL
1 Peaking Generation																		
1	Solar + Storage System																	
1	Solar + Storage System																	
1	Solar + Storage System																	
1	Solar + Storage System																	
1	Solar + Storage System																	
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1	Solar + Storage System																	
1	Solar + Storage System																	
1	Solar + Storage System																	
1	Solar + Storage System																	
	Subtotal																	
2 Energy Storage and Microgrid Systems																		
1	Energy Storage System																	
1	Energy Storage System																	
1	Microgrid																	
1	Microgrid																	
1	Microgrid																	
1	Microgrid																	
	Subtotal																	
3 Renewables																		
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	Subtotal																	
4 Grand Total																		
5 Cumulative Total																		

[redacted]

Accelerate Portfolio - Capital Costs
Generation Construction Cash Flow without AFUDC
in Millions of Dollars

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Capital Costs through 2035 TOTAL
1 Peaking Generation																		
1	Solar + Storage System	[redacted]																
1	Solar + Storage System																	
1	Solar + Storage System																	
1	Solar + Storage System																	
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1	Solar + Storage System																	
1	Solar + Storage System																	
1	Solar + Storage System																	
1	Solar + Storage System																	
	Subtotal																	
2 Energy Storage and Microgrid Systems																		
1	Energy Storage System	[redacted]																
1	Energy Storage System																	
1	Energy Storage System																	
1	Energy Storage System																	
1	Energy Storage System																	
1	Energy Storage System																	
1	Energy Storage System																	
1	Microgrid																	
	Subtotal																	
3 Renewables																		
	New Wind	[redacted]																
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	New Wind																	
	Subtotal																	
4 Grand Total																		
5 Cumulative Total																		

ATTACHMENT D.1(F): TRANSMISSION PROJECTS

CONFIDENTIAL

PROJECT DESCRIPTION	ISD	PARTICIPANTS	KV	RATING	TOTAL COST ($MILLIONS)	LENGTH (MILES)	PURPOSE
Scatter Wash 230/69kV substat on	2020	None	230/69	188 MVA	[redacted]	<1	To prov de electr c energy in the northern port ons of the Phoenix Metropolitan area as well as increase the reliabil ty for these areas. The load in North Phoenix is increasing and this substation will prov de a new transmission source to maintain the reliability of the local 69kV system serving the area.
Freedom 230/69kV substation	2020	None	230/69	188 MVA	[redacted]	<1	To prov de electr c energy in the southwestern portions of the Phoenix Metropol tan area and into the Buckeye area. The load in Goodyear and Buckeye is increasing and this substation will provide a new transmiss on source to maintain reliability of the local 69kV system serving the area.
North Gila-Orchard 230kV line circuit #1	2021	None	230	3000 A	[redacted]	~13	To increase ability to import resources into the Yuma load pocket. The project will also be used to improve reliabil ty, serve the need for electric energy, and prov de continuity of serv ce for the greater Yuma area by adding a transmission source in a new area of the Yuma system. This project will have double-circuit capabil ty with one circu t in-service in 2021 and the second circu t in-service TBD.
Runway 230kV lines	2021	None	230	TBD	[redacted]	<1	To prov de electr c energy to a new high load customer in the area. In-serv ce date is predicated on ramp rate of customer load.
Stratus 230kV lines	2022	None	230	TBD	[redacted]	<1	To prov de electr c energy to a new high load customer in the area. In-serv ce date is predicated on ramp rate of customer load.
Three Rivers 230kV lines	2023	None	230	TBD	[redacted]	~4	To prov de electr c energy to a new high load customer in the area. In-serv ce date is predicated on ramp rate of customer load.
Contrail 230kV lines	2023	None	230	TBD	[redacted]	~7	To prov de electr c energy to a new high load customer in the area. In-serv ce date is predicated on ramp rate of customer load.
TS2 230kV lines	2023	None	230	TBD	[redacted]	<1	To prov de electr c energy to a new high load customer in the area. In-serv ce date is predicated on ramp rate of customer load.
Broadway 230kV lines	2024	None	230	TBD	[redacted]	<1	To prov de electr c energy to a new high load customer in the area. In-serv ce date is predicated on ramp rate of customer load.
TS17 230kV lines	2025	None	230	367 MVA	[redacted]	<1	To prov de electr c energy in the northeastern port ons of the Phoenix Metropol tan area. The load in northeastern portions of the Phoenix Metropol tan area is increasing and this substation will prov de a new transmission source to maintain the reliability of the local 69kV system serving the area. Add t onally, this substat on offloads multiple heavily loaded 230kV lines in the Phoenix Metropol tan area.

[redacted]

Source: 2020-2029 Ten-Year Transmission System Plan dated January 2020

ATTACHMENT D.3: GENERATION TECHNOLOGIES

Conventional Generation Technologies Assumptions											
Plant	Location	Annual Capacity	Summer Capacity	Capital Cost ($/kW)	Book Life (Years)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)	Heat Rate (BTU/kWh)	Capacity Factor %	CO2 Emmissions (lbs/mmBTU)	Water Consumption (gal/MWh)
NUCLEAR											
Advanced Nuclear	Palo Verde	2156 MW	2156 MW	6,830	40	121.13	2.54	10,461	92%	0	767
Small Modular Reactor (SMR)	Palo Verde	600 MW	600 MW	5,605	40	173.35	15.50	10,710	95%	0	740
NATURAL GAS											
Large Frame Combustion Turbine	Maricopa	384 MW	362 MW	652	40	11.58	2.10	9,319	10%	125	15
Aeroderivative Combust on Turbine	Maricopa	104 MW	103 MW	1,512	40	8.86	2.68	9,138	10%	122	141
Combined Cycle	Maricopa	547 MW	542 MW	994	40	7.72	2.72	6,672	50%	122	20
MICROGRID											
Genset	Maricopa	100 MW	100 MW	946	40	5.88	0	8,300	2%	161	0
ENERGY STORAGE											
Battery Energy Storage System (Li-ion)	Maricopa	100 MW	100 MW	1,225	20	24.50	0	*85%	15%	0	0
Compressed Air Energy Storage (CAES)	Maricopa	100 MW	100 MW	3,878	30	22.74	1.88	4,000	15%	122	0
Pumped Storage Hydro	Maricopa	100 MW	100 MW	3,546	30	49.64	0	*75%	15%	0	0
Flow Battery	Maricopa	100 MW	100 MW	1,570	30	31.40	0	*75%	15%	0	0

Renewable Generation Technologies Assumptions									
Generation Resource Options	Summer Capacity	Capital Cost ($/kW)	Book Life (Years)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)	Capacity Factor %	CO2 Emmissions (lbs/mmBTU)	Water Consumption (gal/MWh)	Fuel Cost ($/MWh)
GRID-SCALE SOLAR									
Thin Film Solar PV - Single Axis Util ty	100 MW	1,160	40	17.86	0	35%	0	0	0
Thin Film Solar PV - Fixed Util ty	100 MW	1,084	40	17.86	0	25%	0	0	0
Solar PV + Battery Energy Storage System (PVS)	100 MW	2,385	40	42.36	0	34%	0	0	0
Solar Thermal Tower with Storage	130 MW	7,107	40	83.46	0	54%	0	134	0
Distributed Solar									
Thin Film Solar PV - Fixed Commercial	150 kW	1,260	40	21.00	0	20%	0	0	0
Thin Film Solar PV - Fixed Res dential	5 kW	2,687	40	30.77	0	22%	0	0	0
OTHER RENEWABLE ENERGY SOURCES									
Southwest Wind	150 MW	1,343	40	34.73	0	50%	0	0	0
Geothermal	50 MW	3,034	30	122.00	1.25	80%	0	221	0
Biomass	50 MW	4,666	30	134.82	5.18	80%	0	553	36

Notes:

* Efficiency

1 Costs are in year-2022 dollars

2 Capital costs are overnight construction costs; $/kW is based on summer capacity rating

3 Duration for each energy storage technology is 4 hours

ATTACHMENT D.10-1: TOTAL REVENUE REQUIREMENTS - BRIDGE PORTFOLIO

Total Revenue Requirements - Bridge Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2020	774.0	408.6	59.7	325.1	66.1	1,633.5	81.8	258.0	339.7	(3.4)	77.9	12.9	0.0	100.5	2,161.2	71.0
2021	821.8	475.1	62.1	345.7	63.8	1,768.6	125.9	271.4	397.2	0.0	83.3	16.1	0.0	105.9	2,371.2	75.8
2022	853.1	457.0	63.3	348.7	63.9	1,785.9	130.7	276.6	407.3	0.1	83.3	19.1	0.0	108.0	2,403.6	74.4
2023	921.3	453.5	61.6	376.0	63.9	1,876.3	135.1	285.1	420.2	0.0	83.3	19.8	0.0	110.9	2,510.6	75.4
2024	979.3	477.4	66.1	387.2	63.8	1,973.8	135.4	282.2	417.5	0.6	83.6	17.7	0.0	113.3	2,606.5	76.1
2025	1,134.7	440.5	61.1	378.9	116.2	2,131.3	137.4	292.2	429.6	0.4	84.2	15.5	184.5	119.7	2,965.1	84.2
2026	1,156.2	430.0	67.0	385.2	151.6	2,190.1	144.2	280.9	425.1	0.1	84.2	16.8	177.5	122.9	3,016.7	83.3
2027	1,215.8	426.8	71.5	411.7	168.7	2,294.5	156.4	266.7	423.1	0.0	84.2	18.3	177.6	125.6	3,123.4	83.9
2028	1,284.6	471.0	79.4	437.7	183.4	2,456.0	122.2	263.7	385.9	4.3	95.9	15.7	195.4	127.7	3,281.0	85.8
2029	1,388.0	434.8	79.3	467.7	193.1	2,562.9	127.4	234.1	361.5	0.0	87.7	13.8	183.3	132.4	3,341.6	85.1
2030	1,483.3	456.8	83.7	497.5	197.4	2,718.7	134.5	240.6	375.1	6.7	87.9	11.7	191.9	135.2	3,527.3	87.5
2031	1,626.1	363.7	65.9	510.5	212.5	2,778.7	141.0	193.7	334.8	0.0	85.0	13.6	138.3	140.5	3,490.9	84.4
2032	1,761.6	306.9	62.6	501.2	221.8	2,854.2	146.4	174.3	320.7	0.0	87.6	15.8	107.4	135.5	3,521.2	83.4
2033	1,860.1	294.7	59.9	537.5	239.8	2,992.0	153.4	158.5	311.9	0.0	84.4	13.7	102.6	138.1	3,642.7	84.7
2034	1,899.1	293.5	61.7	565.1	247.1	3,066.6	159.0	146.8	305.8	0.1	80.9	11.4	103.0	138.8	3,706.6	84.6
2035	2,006.0	278.8	58.9	608.7	265.5	3,217.8	166.6	113.1	279.6	0.0	81.8	9.0	96.7	141.8	3,826.8	85.7
CPW@7.50%																
(2020-2035)	10,876.2	3,828.1	600.5	3,790.2	1,222.8	20,317.9	1,207.8	2,258.3	3,466.1	2.9	767.3	142.0	801.0	1,096.3	26,593.4	80.7

ATTACHMENT D.10-2: TOTAL REVENUE REQUIREMENTS - SHIFT PORTFOLIO

Total Revenue Requirements - Shift Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2020	774.0	408.3	59.8	325.1	66.1	1,633.3	81.8	257.9	339.7	(3.4)	77.9	12.9	0.0	100.5	2,160.9	70.9
2021	821.8	473.8	61.9	345.7	63.8	1,767.1	125.9	271.9	397.8	0.0	83.3	16.1	0.0	105.9	2,370.2	75.8
2022	853.1	456.7	63.3	348.7	63.9	1,785.6	130.7	276.6	407.3	0.1	83.3	19.1	0.0	108.0	2,403.2	74.4
2023	921.3	453.5	61.6	376.0	63.9	1,876.3	135.1	285.3	420.4	0.0	83.3	19.8	0.0	110.9	2,510.8	75.5
2024	979.3	477.1	66.2	387.2	63.8	1,973.6	133.3	282.4	415.8	0.5	83.6	17.7	0.0	113.3	2,604.6	76.0
2025	1,134.7	441.2	61.1	378.9	116.2	2,132.0	137.3	292.5	429.8	0.6	84.2	15.5	184.8	119.7	2,966.5	84.2
2026	1,156.2	429.9	67.0	385.2	151.6	2,190.0	144.2	281.0	425.1	0.1	84.2	16.8	177.5	122.9	3,016.6	83.3
2027	1,222.8	424.4	71.2	412.7	168.9	2,300.1	156.5	266.0	422.5	0.0	84.2	18.3	176.6	125.6	3,127.4	84.0
2028	1,339.0	460.1	76.5	446.4	181.3	2,503.3	123.1	261.6	384.7	1.7	91.1	15.7	189.1	127.7	3,313.5	86.6
2029	1,457.9	419.9	77.1	479.6	189.2	2,623.7	128.3	232.0	360.3	0.0	82.2	13.8	176.0	136.1	3,392.0	86.3
2030	1,532.8	453.8	82.8	507.4	192.4	2,769.2	133.9	228.7	362.7	4.7	84.0	11.7	189.6	138.9	3,560.8	88.3
2031	1,744.5	329.1	58.5	533.8	210.1	2,876.0	144.0	189.2	333.2	0.0	76.3	13.6	122.1	144.2	3,565.3	86.2
2032	1,934.3	261.6	51.9	534.8	221.9	3,004.5	150.4	168.1	318.5	0.0	76.7	15.8	86.8	139.2	3,641.5	86.3
2033	2,062.9	247.4	48.2	578.3	241.9	3,178.7	157.9	146.9	304.8	0.0	74.5	13.7	80.9	141.7	3,794.3	88.2
2034	2,136.8	239.9	47.9	615.0	265.0	3,304.5	164.2	129.8	294.0	0.0	71.2	11.4	78.0	142.5	3,901.6	89.0
2035	2,294.8	222.2	43.5	671.3	280.1	3,511.8	172.7	93.6	266.3	0.0	71.2	9.0	70.1	145.5	4,073.8	91.2
CPW@7.50%																
(2020-2035)	11,322.8	3,726.6	576.5	3,879.2	1,228.0	20,733.1	1,215.2	2,231.2	3,446.4	0.7	742.4	142.0	753.6	1,106.3	26,924.4	81.7

ATTACHMENT D.10-3: TOTAL REVENUE REQUIREMENTS - ACCELERATE PORTFOLIO

Total Revenue Requirements - Accelerate Portfolio ($Millions)																
YEAR	GENERATION						PURCHASES			SALES					TOTAL	
	Capital Rev. Req.	Fuel	Var . O&M	Fixed Fuel + O&M	New Trans-mission	Sub Total	Demand	Energy	Sub Total		Gas Transport	Imputed Debt	EMIS Costs	DE-EE Costs	$Millions	$/MWH
2020	774.0	408.4	59.8	325.1	66.1	1,633.5	81.8	257.7	339.5	(3.4)	77.9	12.9	0.0	100.5	2,160.9	70.9
2021	821.8	474.4	61.9	345.7	63.8	1,767.7	125.9	272.0	397.9	0.0	83.3	16.1	0.0	105.9	2,370.9	75.8
2022	853.1	456.5	63.2	348.7	63.9	1,785.4	130.7	277.1	407.7	0.1	83.3	19.1	0.0	108.0	2,403.5	74.4
2023	921.3	451.3	61.6	376.0	63.9	1,874.0	133.1	297.9	431.0	0.0	83.3	20.3	0.0	110.9	2,519.6	75.7
2024	979.3	474.5	65.0	387.2	63.8	1,969.8	133.2	305.4	438.6	0.5	83.3	18.1	0.0	113.3	2,623.8	76.6
2025	1,123.5	442.4	61.0	376.1	65.7	2,068.7	136.5	316.1	452.6	0.6	84.2	15.9	185.3	119.7	2,927.1	83.1
2026	1,246.8	408.3	62.0	396.9	69.4	2,183.3	104.5	304.4	408.9	0.0	84.2	13.5	169.2	122.9	2,981.9	82.3
2027	1,455.7	394.2	60.5	444.3	74.4	2,429.2	73.9	290.2	364.1	0.0	84.2	11.7	162.2	125.6	3,177.1	85.4
2028	1,702.4	423.6	65.6	502.2	147.1	2,841.0	39.5	280.7	320.2	0.4	78.0	10.5	172.8	127.7	3,550.6	92.8
2029	1,866.0	364.5	59.8	547.3	196.6	3,034.2	44.8	248.3	293.1	0.0	76.3	10.0	149.8	136.1	3,699.5	94.2
2030	1,944.0	423.5	68.5	577.2	220.9	3,234.0	45.3	238.3	283.6	2.3	73.0	9.4	173.6	138.9	3,914.7	97.1
2031	2,256.3	266.7	40.2	624.4	254.3	3,441.8	55.8	220.0	275.8	0.0	71.2	8.8	93.5	144.2	4,035.3	97.5
2032	2,525.5	182.1	27.4	643.9	291.5	3,670.4	62.2	199.4	261.6	0.0	71.4	8.2	51.2	139.2	4,202.1	99.5
2033	2,705.9	167.7	23.3	702.5	313.1	3,912.6	67.9	176.8	244.7	0.0	71.2	7.5	44.6	141.7	4,422.3	102.8
2034	2,816.4	157.5	20.8	752.6	332.2	4,079.6	72.6	159.0	231.5	0.0	71.2	6.8	40.1	142.5	4,571.7	104.3
2035	2,984.0	148.1	18.1	818.0	356.9	4,325.1	78.0	122.9	201.0	0.0	71.2	6.1	35.3	149.7	4,788.4	107.2
CPW@7.50%																
(2020-2035)	13,184.9	3,499.1	503.3	4,211.2	1,209.4	22,607.8	856.4	2,376.4	3,232.8	(1.1)	722.3	122.0	650.5	1,107.6	28,441.9	86.3

ATTACHMENT D.14(A): EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT

PROGRAM TYPE	NAME	DEPLOYMENT	RESIDENTIAL EE PROGRAM DESCRIPTION
Residential EE	1. Existing Homes	On-going	APS combined the Consumer Products, Existing Homes HVAC, and Home Performance w th ENERGY STAR programs into one comprehensive Existing Homes program. The combined program offers a one-stop shop for APS customers and local trade allies to access all of the DSM program savings opportunities that are available for existing homes under one convenient umbrella including HVAC, Home Performance w th Energy Star and smart thermostats.
Residential EE	2. New Construction	On-going	The Res dential New Construct on program promotes high efficiency construction practices for new homes through builder incentives. While the program emphasizes the "whole building" approach to improving EE and includes field testing of homes to ensure compliance with APS performance standards that are based off the EPA ENERGY STAR Homes program, participation in other Residential New Construct on program measures including EV Pre-Wire and Smart Thermostats, EV Pre-Wire, Induction Cooking, and Connected Water Heating.
Residential EE	3. Low Income Weatherization	On-going	APS's Energy Wise Low Income Weatherization program is designed to improve the energy eff ciency, safety, and health attributes of homes occupied by customers whose income falls within 200% of the Federal Poverty Guidelines. The weatherization component of this program serves low-income customers w th various home improvement measures, including cooling system repair and replacement, insulation, sunscreens, water heaters, window repairs and improvements, as well as other general household repairs. These programs are administered by var ous community action agencies throughout APS's service territory. In 2020, the program partnered with local weatherizat on agencies and a non-prof t multi-family rehabilitat on project expert to encourage comprehensive retrofits of limited income multi-family properties. These projects leverages program funds with capital from building owners and other funding sources to offer added benefits for customers and extend the reach of program funds to improve cost effectiveness. In response to stakeholder input, the program will also target support to reach disadvantaged communities and prov de upgrades for multifamily properties where at least the minimum 66% of residents are qualifying limited income customers, but where the program can also help other building tenants who are just above the federal income gu delines.
Residential EE	4. Conservat on Behav or	On-going	The Residential Conservation Behav or program provides part cipating residential customers with periodic reports containing informat on designed to help motivate them to adopt energy conservation behaviors. The program provides direct-mailed reports to part cipants to show how the energy usage in their home compares with energy eff cient and other similar homes. In 2020, APS expanded the use of Home Energy Reports as a tool to help lim ted income customers learn how their home uses energy and the best ways to save money on their home energy costs. APS will introduce a new Home Energy Report delivered to all APS limited income customers in the APS Energy Support Program that will focus on no/low cost energy savings tips and provide information about assistance programs and other support available.
Residential EE	5. Multi-Family Construct on	On-going	The Multi-Family Energy Eff ciency Program (MEEP) is a program that targets multi-family properties and dorm tories with measures and solutions designed to promote energy and demand savings. MEEP offers one new measure for rate optimized smart thermostats and two new pilot measures including connected water heaters/water heater controls and induction cooking.
Residential & Non-Res dential EE	6. Codes & Standards	On-going	APS may count toward meeting the standard up to one third of the energy savings, resulting from energy eff ciency building codes and appliance standards, that are quantified and reported through a measurement and evaluat on study.

ATTACHMENT D.14(A): EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT (CONTINUED)

PROGRAM TYPE	NAME	DEPLOYMENT	RESIDENTIAL DR PROGRAM DESCRIPTION
Residential DR	1. TOU-E Saver Choice (3pm-8pm)	On-going	TOU-E (Saver Choice) is a seasonal energy-only rate. It has a summer per od of May-October with all other months being winter. The rate features an on-peak per od from 3pm-8pm for both summer and winter seasons. During the winter season this rate gains a super off-peak per od from 10am-3pm. The program was approved in A.C.C. Decis on No. 76295 in August 2017.
Residential DR	2. R-2 Saver Choice Plus (3pm-8pm)	On-going	R-2 (Saver Choice Plus) is a seasonal two part rate that includes both demand and energy charges. It has a summer period of May-October with all other months being winter. The rate features an on-peak period from 3pm 8pm for both summer and winter seasons. The program was approved in A.C.C. Decision No. 76295 in August 2017.
Residential DR	3. R-3 Saver Choice Max (3pm-8pm)	On-going	R-3 (Saver Choice Max) is a seasonal two part rate that includes both demand and energy charges. It has a summer period of May-October with all other months being winter. The rate features an on-peak period from 3pm 8pm for both summer and winter seasons. The rate has a stronger demand pr ce signal over R-2.The program was approved in A.C.C. Decis on No. 76295 in August 2017.
Residential DR	4. R-Tech Saver Choice Tech Pilot (3pm-8pm)	On-going	R-Tech (Saver Choice Tech) is a seasonal two part rate that includes an on-peak and off-peak demand and energy charges. It has a summer per od of May-October with all other months being winter. The rate features an on-peak per od from 3pm-8pm for both summer and winter seasons. The rate features a stronger demand price signal over R-3 and a demand charge for off peak kW greater than 5 kW. This rate is only available to customers that have newly installed primary technologies such as solar, battery storage, or an electr c vehicle, or two secondary technologies such as a variable speed HVAC, grid-interactive water heater, smart thermostat or an automated load controler. This program has an in tial cap of 10,000 customers and was approved in A.C.C. Decision No. 76295 in August 2017.
Residential DR	5. ET-1 Time Advantage (9am-9pm)	Frozen to new customers	ET-1 (Time Advantage) has an energy-only rate with an on-peak period from 9am-9pm. The program has been in place since 1982. In a previous rate case approved under A.C.C. Decis on No. 71448, APS closed the series ET-1 rate to new customers. This rate is frozen and lim ted to only existing customers on the rate w th distributed generat on effective August 2017 in ACC Decis on No. 76295.
Residential DR	6. ECT-1R Combined Advantage (9am-9pm)	Frozen to new customers	ECT-1R (Combined Advantage) includes both demand and energy charges. Similar to the ET-1 rate schedule, the peak hours are from 9am-9pm. APS anticipates closing the rate to all customers w thin the next three years and transitioning any remaining customers to the ET-2 or ECT-2 rates. This rate is frozen and lim ted to only existing customers on the rate with distributed generation effective August 2017 in ACC Decision No. 76295.
Residential DR	7. ET-2 Time Advantage (Noon – 7pm)	Frozen to new customers	ET-2 (Time Advantage) has an energy-only rate with an on-peak period from Noon- 7:00pm. This rate is frozen and limited to only existing customers on the rate with distributed generat on effective August 2017 in ACC Decision No. 76295.
Residential DR	8. ECT-2 Combined Advantage (Noon – 7pm)	Frozen to new customers	ECT-2 (Combined Advantage) includes demand and energy charges with a peak period of Noon – 7:00pm. This rate is frozen and limited to only existing customers on the rate with distributed generat on effective August 2017 in ACC Decis on No. 76295.
Residential DR	9. Peak Event Pr cing (also referred to as Cr t cal Peak Pricing)	On-going	Provides a high pr ce signal over a small number of core summer peak days and hours. The program can be called on when the Company is experiencing extreme temperatures, very high electr cal demand, high market electric costs, or is experiencing a major generat on or transmiss on disturbance. The cr tical peak pr ce signal is "dynamic" in that it is callable by APS for up to 18 days and 90 hours per year, weekdays during the months June through September. APS declares a "critical event" day and notifies participants by 4:00 p.m. the pr or day. During the event the customer is charged an add tional $0.25 per kWh for consumpt on during the hours 3 p.m. to 8pm. The customer also receives a discount of approximately $0.012143 per kWh for all consumpt on during the June through September billing cycles. The prices are designed so that the monthly discounts equal the crit cal peak charges for the typical customer. Therefore, to save money, the customer must be able to reduce usage during cr t cal hours.
Residential & Non-Res dential DR	10. Energy & Demand Management Education Pilot	Ongoing	This pilot focuses on energy information tools, including web based energy and demand analyzers, personalized v deos to guide customers through targeted savings opportunities that match their usage profiles, and enhance mobile phone apps that can provide near real time feedback on a home's demand and energy use. A key objective of the pilot is to measure the EE savings resulting from behavioral changes in energy use that occur when the customer receives the enhanced energy information.
Residential & Non-Res dential DR	11. EV Load Management Pilot	Proposed	In 2020, APS filed for the EV Load Management Pilot which is designed to manage the peak demand impacts of the emerging electric veh cle market and help encourage beneficial charging behav or. The proposed pilot includes elements to help gather better load research on EV charging behav ors, as well as elements to encourage off peak charging and to conduct demand response with EV charging stations.
Residential & Non-Res dential DR	12. Demand Response, Energy Storage and Load Management Program	On-going	In 2016, APS filed for the Residential Demand Response, Energy Storage and Load Management (DRESLM) program which is deploying commercially available load management and load shifting technologies. The program is designed to support the deployment of res dential load management, demand response and energy storage technologies that help APS residential customers shift energy use and manage peak demand while also providing system peak reduction and other grid operat onal benefits. The program includes three elements: battery storage w th residential and commercial batteries, thermal storage with residential connected water heaters, and demand response w th almost 20,000 part cipating res dential smart thermostats.
Non-Res dential DR	13. Reverse Demand Response Pilot	Proposed	APS has proposed a non-residential reverse demand response pilot in the 2018-2020 DSM Plans that are awa ting ACC review. The pilot seeks to work with non-residential customers to deploy loads in response to excess generat on events, when there is negatively priced renewable energy available to be utilized for productive energy uses rather than be curtailed due to a lack of demand. The pilot is designed to help balance loads and prov de addit onal distributed flexible capac ty that can be used to help flatten system load shapes, reduce ramping needs, and integrate more renewable energy.

ATTACHMENT D.14(A): EE AND DR PROGRAM DESCRIPTIONS AND DEPLOYMENT (CONTINUED)

PROGRAM TYPE	NAME	DEPLOYMENT	NON-RESIDENTIAL EE PROGRAM DESCRIPTION
Non-Res dential EE	1. Existing Facilities	On-going	The Existing Facil ties program is targeted at customers for EE improvements in HVAC, motors, building envelope, and refrigeration measures. The program includes Large Existing facil ties and Small Business. In 2020, APS added five new electrificat on pilot measures w thin the Non-Res dential Existing Facilities and New Construct on program including: Standby truck refrigerat on, Electr c forklifts, Airplane tugs, Airport luggage carts, and Airport luggage conveyors. APS is also proposing new EE measures designed for data canters. Incentives are also provided to customers who conduct qualifying energy studies. Custom incentives are also provided for EE measures not covered by the prescriptive incentives.
Non-Res dential EE	2. New Construction	On-going	The Non-Residential New Construct on program includes three components: (1) design assistance; (2) prescriptive measures; and, (3) custom efficiency measures. Design assistance involves efforts to integrate EE into a customer's design process to influence equipment/system selection early on in the process. Prescriptive incentives are available for EE improvements in measures such as HVAC, motors, building envelope, and refrigerat on appl cations. Whole Building Design is a component within the New Construct on custom eff ciency measures that influences customers, developers, and design profess onals to design, build, and invest in higher performing building through a stepped performance incentive structure w th the financial incentives increasing as the building performance improves.
Non-Res dential EE	3. Schools	On-going	The Schools program is designed to set as de funding for K-12 publ c, private, and charter school buildings. Schools can receive up to a maximum of $100,000 in incentives per year. EE incentives for Schools are the same as in the Existing Facil ties (for existing school facil ties) and New Construct on (for new school construction and major renovat on projects) programs. In addition, any size school may receive Direct Install measure incentives and is eligible to receive APS-arranged program financing for their EE projects.
Non-Res dential EE	4. Energy Informat on Systems	On-going	The Energy Informat on Systems program is a subscription serv ce for software that prov des 15-minute interval electr c usage data to large non-res dential customers through a web-based energy information tool. This tool provides users w th information that can be used to improve or mon tor energy usage patterns, reduce energy use, reduce demands during on-peak per ods, and to better manage overall energy operations.

PROGRAM TYPE	NAME	DEPLOYMENT	NON-RESIDENTIAL DR PROGRAM DESCRIPTION
Non-Res dential DR	1. E-20	Frozen to new customers	Intended for houses of worship, E-20 was implemented in 1996. On-peak and off-peak charges are included for both energy and demand. This rate was frozen to new customers as of July 1, 2013.
Non-Res dential DR	2. E-221-8T	On-going	Designed for water pumping customers, the E-221-8T rate was implemented in 1986. On-peak and off-peak charges are included for both energy and demand.
Non-Res dential DR	3. E-32 XS TOU	On-going	For business customers, the E-32TOU rates (wh ch include extra small, small, medium, and large customers) were implemented in 2005 and are available for customers w th less than 3 MW of monthly peak demand. On-peak and off-peak charges are included for both energy and demand.
Non-Res dential DR	4. E-32 S TOU		
Non-Res dential DR	5. E-32 M TOU		
Non-Res dential DR	6. E-32 L TOU		
Non-Res dential DR	7. E-35	On-going	E-35 was implemented in 1988 for extra large business customers exceeding 3 MW of monthly peak demand. On-peak and off-peak charges are included for both energy and demand.
Non-Res dential DR	8. GS-Schools M	On-going	Designed for public and private schools prov ding primarily on-site K-12 education, the GS-Schools TOU rates were implemented in 2010 and are available to schools with less than 3 MW of monthly peak demand. The rates contain energy charges for three seasons including summer peak (June-August), summer shoulder (May, September and October) and winter (November through April). The demand charge is computed based on the monthly maximum demand.
Non-Res dential DR	9. GS-Schools L		
Non-Res dential DR	10. IRR-Interruptible Rate	On-going	The rate rider IRR was approved for July 1st 2012. IRR provides interruptible service for extra-large general serv ce customers who can interrupt at least 500 kW of load when requested by the Company. Under this service, the customer can choose between two curtailment opt ons, two notificat on opt ons, and a one-year or five-year agreement. The customer receives capacity and energy payments for the interruptible load based on these opt ons. The customer may also incur a penalty for failing to curtail when requested. Customers in Metro Phoenix and Yuma area are not eligible for this rate until January 1st 2015.
Non-Res dential DR	11. Peak Solutions	On-going	APS Peak Solutions is a DR program approved in ACC Decision 71104 that offers financial incentives to eligible commercial and industrial customers to reduce their electr city usage during APS's summer peak per ods (June through September) between 1:00 p.m. and 7:00 p.m. daily. Load reductions are often for HVAC systems, lighting, refrigerat on, and industrial processes.[2]

1 Details on the Builder Opt on Packages can be found in Decision No. 72060 (Docket No. E-01345A-10-0219).
2 APS Peak Solutions Appl cat on filed, 11/6/2008, Docket E-01345A-08-0569.

ATTACHMENT D.14(B): EE PROGRAM PARTICIPATION[1]

RESIDENTIAL PROGRAM NAME	MEASURE OR UNIT	ACTUAL PARTICIPATION IN 2019
Existing Homes	Giveaway LED Bulbs	25,798
	Direct Install LED Bulbs	7,480
	Smart Thermostats	11,546
	On-line Energy Audits	42,901
	Low Flow Shower Heads	1,496
	Insulation	823
	AC with Quality Installation	3,147
	Duct Test & Repair	1,181
	Cooling Control	73
Residential New Construction	Smart Thermostats	10,747
	APS ENERGY STAR® Homes V3.0	7,660
Multi-Family	Low Flow Shower Heads	1,004
	Low Flow Aerators	2,046
	CFL & LED Bulbs	49,395
	AC with Quality Installation	1
	NC Builder Package	1,288
Low Income Weatherization	Homes Weatherized	554
Behavioral	Reports Generated	321,537
NON-RESIDENTIAL PROGRAM NAME	**MEASURE OR UNIT**	**ACTUAL PARTICIPATION IN 2019**
Existing Facilities	No. of Applications Paid	205
New Construction	No. of Applications Paid	34
Schools	No. of Applications Paid	42
Energy Information Systems	No. of Meters	553

[1] Additional details pertaining to EE programs were provided in the 2019 APS Annual DSM Progress Report filed with the ACC on February 2020.

ATTACHMENT D.16: GAS TRANSPORT ANALYSIS

YEAR	2020		2021		2022		2023		2024	
Season	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**527,450**	**260,239**	**570,865**	**226,600**	**616,954**	**255,731**	**649,425**	**286,403**	**662,950**	**317,287**
Current firm fuel contracts										
El Paso - FT3HX000	99,392	36,888	99,392	36,888	99,994	36,888	99,392	36,888	99,392	36,888
El Paso - FT39D000	108,266	56,145	108,266	56,145						
El Paso - FT39E000	33,473	11,250	33,473	11,250						
El Paso - FT39H000	31,500	19,000	31,500	19,000	31,500	19,000	31,500	19,000	31,500	19,000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25,500	28,000	25,500		
El Paso - H822G000 / 613904[1]	1,078		1,078		4,751		1,078		1,078	
El Paso - 610506	15,000	15,000	15,000	15,000	15,000	15,000				
El Paso - 611222[2]	72,593		30,759		30,759		30,759		30,759	
El Paso - 613881[3]			31,200		31,200		31,200		31,200	
El Paso - 613878[3]			40,200		40,200		40,200		40,200	
Transwestern - 102446	220,000	140,000	220,000	140,000	220,000	140,000	220,000	140,000		140,000
Transwestern - 104819[2]	21,400		53,900		53,900		53,900		53,900	
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750
Total Current firm contracts[4]	**633,202**	**303,783**	**695,268**	**303,783**	**557,804**	**236,388**	**536,029**	**221,388**	**288,029**	**195,888**
Rollover ROFR firm fuel contracts										
El Paso - FT3HX000										
El Paso - FT39D000					100,742	36,795	108,266	56,145	108,266	36,795
El Paso - FT39E000					24,375	5,638	33,473	11,250	33,473	5,638
El Paso - FT39H000										
El Paso - H822E000									30,500	25,500
El Paso - H822G000 / 613904[1]										
El Paso - 610506							15,000	15,000	15,000	15,000
El Paso - 611222[2]										
El Paso - 613881[3]										
El Paso - 613878[3]										
Transwestern - 102446									220,000	
Transwestern - 104819[2]										
North Baja - A027F1 (Yuma Only)										
North Baja - YA027F1 (Yuma Only)										
Total ROFR firm contracts[4]	**0**	**0**	**0**	**0**	**125,117**	**42,433**	**156,739**	**82,395**	**407,239**	**82,933**
Future fuel contracts[5]										
Long Term Seasonal Firm Purchases										
Short Term Purchases[6]	448	9,242	591	3,361	9,624	2,148	14,870	9,670	26,003	46,529
Total future contracts	**448**	**9,242**	**591**	**3,361**	**9,624**	**2,148**	**14,870**	**9,670**	**26,003**	**46,529**
Total contract rights	633,650	313,025	695,859	307,144	692,545	280,969	707,638	313,453	721,271	325,350
LONG/(SHORT) CONTRACT RIGHTS	**106,201**	**52,785**	**124,994**	**80,545**	**75,591**	**25,239**	**58,213**	**27,049**	**58,321**	**8,063**

[1]H822G000 expires 10/31/2020 and will be superseded by 613904 on 04/01/2020.

[2]Contract serves Griffith PPA.

[3]Contract serves South Point PPA.

[4]North Baja capacity serving only Yuma is not included in total current firm contracts.

[5]Based upon hourly optimizat on analysis.

[6]Short Term Purchases include future potential gas transportat on contracts and delivered gas products to cover shortfall in transportat on.

ATTACHMENT D.16: GAS TRANSPORT ANALYSIS (CONTINUED)

Year	2025		2026		2027		2028		2029	
Season	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	**761,751**	**382,396**	**824,906**	**369,975**	**838,525**	**366,909**	**877,563**	**462,470**	**924,236**	**475,188**
Current firm fuel contracts										
El Paso - FT3HX000										
El Paso - FT39D000										
El Paso - FT39E000										
El Paso - FT39H000										
El Paso - H822E000										
El Paso - H822G000 / 613904[1]	1,078		4,751		19,494					
El Paso - 610506										
El Paso - 611222[2]	30,759		30,759							
El Paso - 613881[3]	31,200		31,200		31,200					
El Paso - 613878[3]	40,200		40,200		40,200					
Transwestern - 102446										
Transwestern - 104819[2]	65,600		65,600							
North Baja - A027F1 (Yuma Only)										
North Baja - YA027F1 (Yuma Only)										
Total Current firm contracts[4]	**168,837**	**0**	**172,510**	**0**	**90,894**	**0**	**0**	**0**	**0**	**0**

Rollover ROFR firm fuel contracts										
El Paso - FT3HX000	99,392	53,302	99,994	36,888	86,938	43,870	99,994	38,265	86,938	53,302
El Paso - FT39D000	108,266	64,839	100,742	56,145	78,550	44,129	100,742	36,795	78,550	64,839
El Paso - FT39E000	33,473	14,747	24,375	11,250	15,395	10,172	24,375	5,638	15,395	14,747
El Paso - FT39H000	31,500	23,000	31,500	19,000	27,000	19,000	31,500	19,000	27,000	23,000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25,500	30,500	25,500	30,500	25,500
El Paso - H822G000 / 613904[1]							4,751		19,494	
El Paso - 610506	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
El Paso - 611222[2]					30,759		30,759		30,759	
El Paso - 613881[3]							31,200		31,200	
El Paso - 613878[3]							40,200		40,200	
Transwestern - 102446	220,000	100,000	220,000	140,000	195,000	100,000	220,000	140,000	195,000	100,000
Transwestern - 104819[2]					65,600		65,600		65,600	
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750	62,750
Total ROFR firm contracts[4]	538,131	296,388	522,111	303,783	544,742	257,671	694,621	280,198	635,636	296,388

Future fuel contracts[5]										
Long Term Seasonal Firm Purchases										
Short Term Purchases[6]	85,394	80,175	126,190	67,715	195,528	110,102	288,867	178,654	359,161	168,373
Total future contracts	**85,394**	**80,175**	**126,190**	**67,715**	**195,528**	**110,102**	**288,867**	**178,654**	**359,161**	**168,373**
Total contract rights	**792,362**	**376,563**	**820,811**	**371,498**	**831,164**	**367,773**	**983,488**	**458,852**	**994,797**	**464,761**
Long/(Short) contract rights	**30,611**	**(5,832)**	**(4,095)**	**1,523**	**(7,361)**	**865**	**105,925**	**(3,618)**	**70,561**	**(10,427)**

[1]H822G000 expires 10/31/2020 and will be superseded by 613904 on 04/01/2020.
[2]Contract serves Griffith PPA.
[3]Contract serves South Point PPA.
[4]North Baja capacity serving only Yuma is not included in total current firm contracts.
[5]Based upon hourly optimizat on analysis.
[6]Short Term Purchases include future potential gas transportat on contracts and delivered gas products to cover shortfall in transportat on.

ATTACHMENT D.16: GAS TRANSPORT ANALYSIS (CONTINUED)

Year	2030		2031		2032	
Season	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	965,337	557,894	1,019,223	541,384	1,085,846	553,161
Current firm fuel contracts						
El Paso - FT3HX000						
El Paso - FT39D000						
El Paso - FT39E000						
El Paso - FT39H000						
El Paso - H822E000						
El Paso - H822G000 / 613904[1]						
El Paso - 610506						
El Paso - 611222[2]						
El Paso - 613881[3]						
El Paso - 613878[3]						
Transwestern - 102446						
Transwestern - 104819[2]						
North Baja - A027F1 (Yuma Only)						
North Baja - YA027F1 (Yuma Only)						
Total Current firm contracts[4]	0	0	0	0	0	0

Rollover ROFR firm fuel contracts						
El Paso - FT3HX000	99,392	41,622	86,938	36,888	99,392	53302
El Paso - FT39D000	108,266	52,026	78,550	56,145	108,266	64839
El Paso - FT39E000	33,473	10,597	15,395	11,250	33,473	14747
El Paso - FT39H000	31,500	19,000	27,000	19,000	31,500	23000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25500
El Paso - H822G000 / 613904[1]	1,078		19,494		1,078	
El Paso - 610506	15,000		15,000		15,000	
El Paso - 611222[2]	30,759		30,759		30,759	
El Paso - 613881[3]	31,200		31,200		31,200	
El Paso - 613878[3]	40,200		40,200		40,200	
Transwestern - 102446	220,000	140,000	195,000	140,000	220,000	100000
Transwestern - 104819[2]	65,600		65,600		65,600	
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62750
Total ROFR firm contracts[4]	706,968	288,745	635,636	288,783	706,968	281388

Future fuel contracts[5]						
Long Term Seasonal Firm Purchases						
Short Term Purchases[6]	342,274	248,243	463,047	255,368	474,454	171,151
Total future contracts	342,274	248,243	463,047	255,368	474,454	171,151
Total contract rights	1,049,242	536,988	1,098,683	544,151	1,181,422	452,539
Long/(Short) contract rights	83,905	(20,905)	79,460	2,767	95,576	(100,622)

[1]H822G000 expires 10/31/2020 and will be superseded by 613904 on 04/01/2020.
[2]Contract serves Griffith PPA.
[3]Contract serves South Point PPA.
[4]North Baja capacity serving only Yuma is not included in total current firm contracts.
[5]Based upon hourly optimizat on analysis.
[6]Short Term Purchases include future potential gas transportat on contracts and delivered gas products to cover shortfall in transportat on.

ATTACHMENT D.16: GAS TRANSPORT ANALYSIS (CONTINUED)

Year	2033		2034		2035	
Season	Summer	Winter	Summer	Winter	Summer	Winter
Peak burn day (mmbtu/day)	1,134,528	626,717	1,216,503	688,080	1,205,421	697,399
Current firm fuel contracts						
El Paso - FT3HX000						
El Paso - FT39D000						
El Paso - FT39E000						
El Paso - FT39H000						
El Paso - H822E000						
El Paso - H822G000 / 613904[1]						
El Paso - 610506						
El Paso - 611222[2]						
El Paso - 613881[3]						
El Paso - 613878[3]						
Transwestern - 102446						
Transwestern - 104819[2]						
North Baja - A027F1 (Yuma Only)						
North Baja - YA027F1 (Yuma Only)						
Total Current firm contracts[4]	0	0	0	0	0	0

Rollover ROFR firm fuel contracts						
El Paso - FT3HX000	99,392	36,888	99,392	36,888	99,994	36888
El Paso - FT39D000	108,266	56,145	108,266	56,145	100,742	56145
El Paso - FT39E000	33,473	11,250	33,473	11,250	24,375	11250
El Paso - FT39H000	31,500	19,000	31,500	19,000	31,500	19000
El Paso - H822E000	30,500	25,500	30,500	25,500	30,500	25500
El Paso - H822G000 / 613904[1]	1,078		1,078		4,751	
El Paso - 610506	15,000		15,000		15,000	
El Paso - 611222[2]	30,759		30,759		30,759	
El Paso - 613881[3]	31,200		31,200		31,200	
El Paso - 613878[3]	40,200		40,200		40,200	
Transwestern - 102446	220,000	140,000	220,000	140,000	220,000	140000
Transwestern - 104819[2]	65,600		65,600		65,600	
North Baja - A027F1 (Yuma Only)	11,000	11,000	11,000	11,000	11,000	11000
North Baja - YA027F1 (Yuma Only)	62,750	62,750	62,750	62,750	62,750	62750
Total ROFR firm contracts[4]	706,968	288,783	706,968	288,783	694,621	288783

Future fuel contracts[5]						
Long Term Seasonal Firm Purchases						
Short Term Purchases[6]	529,050	214,708	608,580	292,360	651,615	306,494
Total future contracts	529,050	214,708	608,580	292,360	0	0
Total contract rights	1,236,018	503,491	1,315,548	581,143	523,733	288,783
Long/(Short) contract rights	101,491	(123,226)	99,045	(106,937)	372,349	140,163

[1]H822G000 expires 10/31/2020 and will be superseded by 613904 on 04/01/2020.
[2]Contract serves Griffith PPA.
[3]Contract serves South Point PPA.
[4]North Baja capacity serving only Yuma is not included in total current firm contracts.
[5]Based upon hourly optimizat on analysis.
[6]Short Term Purchases include future potential gas transportat on contracts and delivered gas products to cover shortfall in transportat on.

ATTACHMENT F.1(A)(1): BRIDGE PORTFOLIO L&R AND ENERGY MIX

	Bridge Portfolio - Loads & Resources - MW Energy Contribution at Peak																
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	**Load Requirements**																
2	APS Peak Demand	7,470	7,650	7,893	8,140	8,390	8,647	8,904	9,165	9,430	9,701	9,972	10,254	10,502	10,754	11,010	11,271
3	Reserve Requirements	1,026	1,113	1,136	1,167	1,193	1,224	1,251	1,278	1,306	1,333	1,362	1,400	1,427	1,453	1,482	1,510
4	**Total Load Requirements**	8,496	8,763	9,029	9,307	9,583	9,871	10,155	10,443	10,736	11,034	11,335	11,653	11,928	12,207	12,492	12,780
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
7	Coal	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	0	0	0	0	0
8	Natural Gas	5,225	5,239	5,239	5,194	5,194	5,194	4,629	4,059	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596
9	Combined Cycle	1,860	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891
10	Combustion / Steam Turbines	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545
11	PacifiCorp Seasonal Exchange	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	1,135	1,598	1,598	1,598	1,598	1,598	1,033	463	0	0	0	0	0	0	0	0
13	Market / Call Options / Hedges /AG-X	205	205	205	160	160	160	160	160	160	160	160	160	160	160	160	160
14	Renewable Energy	485	487	481	474	468	462	445	433	425	409	400	394	389	365	367	360
15	Distributed Energy	8	8	8	9	9	9	9	9	9	9	9	9	9	8	8	8
16	Solar	395	397	391	397	391	385	367	373	366	350	351	345	340	320	322	316
17	Wind	55	55	55	55	55	55	55	37	37	37	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
19	B omass/Biogas	16	16	16	3	3	3	3	3	3	3	3	3	3	0	0	0
20	Energy Storage	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	Microgr d	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
22	**Total Existing Resources**	8,245	8,261	8,257	8,205	8,198	7,806	7,223	6,641	6,171	6,154	6,146	5,169	5,165	5,140	5,143	5,136
23	**Customer Resources**																
24	Future Energy Efficiency	105	189	274	357	439	486	567	644	726	814	890	922	991	1,064	1,133	1,207
25	Future Distributed Energy	4	8	12	18	26	39	53	71	90	110	132	154	175	191	210	225
26	Demand Response (Future & Existing)	21	62	75	87	100	137	149	162	174	212	224	262	274	312	324	337
27	**Total Customer Resources**	130	259	361	463	564	661	769	877	990	1,135	1,246	1,338	1,439	1,567	1,667	1,768
28	**Future Resources**																
29	Natural Gas	150	237	134	50	37	0	565	1,135	1,497	1,497	1,497	1,859	1,859	1,859	1,859	1,859
30	Combined Cycle	0	0	0	0	0	0	565	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135
31	Combustion Turbines	0	0	0	0	0	0	0	0	362	362	362	724	724	724	724	724
32	Short-Term Market Purchases	150	237	134	50	37	0	0	0	0	0	0	0	0	0	0	0
33	Renewable Energy	0	0	64	153	150	279	272	351	343	399	475	544	532	585	561	619
34	Wind	0	0	64	153	150	279	272	351	343	399	475	544	532	585	561	619
35	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	B o/Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	PVS (PV + BESS)	0	0	98	193	393	863	1,077	1,222	1,487	1,606	1,774	2,150	2,338	2,452	2,647	2,805
38	Energy Storage	0	0	109	238	236	235	237	236	239	242	244	516	511	507	498	486
39	Microgr d	0	6	6	6	6	31	31	56	56	56	56	106	106	131	131	131
40	**Total Future Resources**	150	243	411	640	821	1,408	2,182	3,000	3,622	3,800	4,045	5,175	5,346	5,534	5,697	5,900
41	**TOTAL RESOURCES**	**8,524**	**8,763**	**9,029**	**9,307**	**9,583**	**9,875**	**10,174**	**10,517**	**10,782**	**11,090**	**11,437**	**11,682**	**11,950**	**12,241**	**12,507**	**12,804**

ATTACHMENT F.1(A)(1): BRIDGE PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Bridge Portfolio

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2020	9,149	6,532	10,974	4,717	6,005	1,256	38,632
2021	9,411	6,795	11,614	4,841	6,191	1,266	40,117
2022	9,344	6,801	11,316	5,899	6,378	1,300	41,038
2023	9,411	6,808	11,111	7,171	6,564	1,289	42,352
2024	9,335	6,792	11,669	8,006	6,750	1,331	43,884
2025	9,411	5,710	10,787	10,565	6,937	1,839	45,249
2026	9,289	5,257	10,956	11,785	7,123	2,156	46,566
2027	9,393	5,178	10,623	13,090	7,309	2,391	47,984
2028	9,353	5,178	11,418	13,746	7,496	2,541	49,732
2029	9,392	5,178	10,239	15,090	7,682	3,372	50,953
2030	9,290	5,170	10,205	17,196	7,869	3,041	52,770
2031	9,393	2,324	10,554	18,894	8,055	4,880	54,100
2032	9,317	0	11,884	20,207	8,241	5,762	55,411
2033	9,393	0	11,113	21,690	8,428	6,038	56,662
2034	9,326	0	10,810	22,858	8,614	6,384	57,992
2035	9,392	0	9,911	24,450	8,800	6,794	59,348

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2020	23.7%	16.9%	28.4%	12.2%	15.5%	3.3%	100.0%
2021	23.5%	16.9%	28.9%	12.1%	15.4%	3.2%	100.0%
2022	22.8%	16.6%	27.6%	14.4%	15.5%	3.2%	100.0%
2023	22.2%	16.1%	26.2%	16.9%	15.5%	3.0%	100.0%
2024	21.3%	15.5%	26.6%	18.2%	15.4%	3.0%	100.0%
2025	20.8%	12.6%	23.8%	23.3%	15.3%	4.1%	100.0%
2026	19.9%	11.3%	23.5%	25.3%	15.3%	4.6%	100.0%
2027	19.6%	10.8%	22.1%	27.3%	15.2%	5.0%	100.0%
2028	18.8%	10.4%	23.0%	27.6%	15.1%	5.1%	100.0%
2029	18.4%	10.2%	20.1%	29.6%	15.1%	6.6%	100.0%
2030	17.6%	9.8%	19.3%	32.6%	14.9%	5.8%	100.0%
2031	17.4%	4.3%	19.5%	34.9%	14.9%	9.0%	100.0%
2032	16.8%	0.0%	21.4%	36.5%	14.9%	10.4%	100.0%
2033	16.6%	0.0%	19.6%	38.3%	14.9%	10.7%	100.0%
2034	16.1%	0.0%	18.6%	39.4%	14.9%	11.0%	100.0%
2035	15.8%	0.0%	16.7%	41.2%	14.8%	11.4%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.

2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts

3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(2): SHIFT PORTFOLIO L&R AND ENERGY MIX

	Shift Portfolio - Loads & Resources - MW Energy Contribution at Peak																
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	**Load Requirements**																
2	APS Peak Demand	7,470	7,650	7,893	8,140	8,390	8,647	8,904	9,165	9,430	9,701	9,972	10,254	10,502	10,754	11,010	11,271
3	Reserve Requirements	1,026	1,113	1,136	1,167	1,193	1,224	1,251	1,278	1,306	1,333	1,362	1,400	1,427	1,453	1,482	1,510
4	**Total Load Requirements**	8,496	8,763	9,029	9,307	9,583	9,871	10,155	10,443	10,736	11,034	11,335	11,653	11,928	12,207	12,492	12,780
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
7	Coal	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	0	0	0	0	0
8	Natural Gas	5,225	5,239	5,239	5,194	5,194	5,194	4,629	4,059	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596
9	Combined Cycle	1,860	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891
10	Combustion / Steam Turbines	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545
11	PacifiCorp Seasonal Exchange	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	1,135	1,598	1,598	1,598	1,598	1,598	1,033	463	0	0	0	0	0	0	0	0
13	Market / Call Options / Hedges /AG-X	205	205	205	160	160	160	160	160	160	160	160	160	160	160	160	160
14	Renewable Energy	485	487	481	474	468	462	445	433	425	409	400	394	389	365	367	360
15	Distributed Energy	8	8	8	9	9	9	9	9	9	9	9	9	9	8	8	8
16	Solar	395	397	391	397	391	385	367	373	366	350	351	345	340	320	322	316
17	Wind	55	55	55	55	55	55	55	37	37	37	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
19	B omass/Biogas	16	16	16	3	3	3	3	3	3	3	3	3	3	0	0	0
20	Energy Storage	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	Microgr d	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
22	**Total Existing Resources**	8,245	8,261	8,257	8,205	8,198	7,806	7,223	6,641	6,171	6,154	6,146	5,169	5,165	5,140	5,143	5,136
23	**Customer Resources**																
24	Future Energy Efficiency	105	189	274	357	439	486	567	644	726	814	890	922	991	1,064	1,133	1,207
25	Future Distributed Energy	4	8	12	18	26	39	53	71	90	110	132	154	175	191	210	225
26	Demand Response (Future & Existing)	21	62	75	87	100	137	149	162	174	237	249	287	299	337	349	362
27	**Total Customer Resources**	130	259	361	463	564	661	769	877	990	1,160	1,271	1,363	1,464	1,592	1,692	1,793
28	**Future Resources**																
29	Natural Gas	150	237	134	50	37	0	565	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135
30	Combined Cycle	0	0	0	0	0	0	565	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135
31	Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Short-Term Market Purchases	150	237	134	50	37	0	0	0	0	0	0	0	0	0	0	0
33	Renewable Energy	0	0	64	153	150	279	272	351	343	383	460	577	562	611	582	647
34	Wind	0	0	64	153	150	279	272	351	343	383	460	577	562	611	582	647
35	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	B o/Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	PVS (PV + BESS)	0	0	98	193	393	871	1,092	1,263	1,867	1,959	2,024	2,575	2,795	2,941	3,172	3,334
38	Energy Storage	0	0	109	238	236	235	237	236	238	241	243	708	690	673	649	620
39	Microgr d	0	6	6	6	6	31	31	31	31	31	56	131	131	131	131	131
40	**Total Future Resources**	150	243	411	640	821	1,416	2,197	3,016	3,614	3,749	3,918	5,125	5,313	5,491	5,670	5,867
41	**TOTAL RESOURCES**	**8,524**	**8,763**	**9,029**	**9,307**	**9,583**	**9,882**	**10,189**	**10,533**	**10,775**	**11,064**	**11,335**	**11,657**	**11,942**	**12,222**	**12,505**	**12,796**

ATTACHMENT F.1(A)(2): SHIFT PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Shift Portfolio

ENERGY (GWH)							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2020	9,149	6,531	10,963	4,720	6,005	1,258	38,626
2021	9,411	6,795	11,564	4,840	6,191	1,291	40,092
2022	9,344	6,802	11,308	5,889	6,378	1,314	41,035
2023	9,411	6,807	11,103	7,172	6,564	1,294	42,351
2024	9,335	6,790	11,661	8,006	6,750	1,364	43,906
2025	9,411	5,710	10,820	10,545	6,937	1,828	45,251
2026	9,289	5,257	10,970	11,773	7,123	2,153	46,565
2027	9,393	5,178	10,520	13,238	7,309	2,357	47,995
2028	9,353	5,178	10,619	14,565	7,496	2,479	49,690
2029	9,392	5,178	9,462	16,031	7,682	3,318	51,064
2030	9,290	5,172	9,831	17,211	7,869	3,377	52,749
2031	9,393	2,324	8,872	20,682	8,055	4,972	54,298
2032	9,317	0	9,711	22,514	8,241	5,890	55,672
2033	9,393	0	8,859	24,137	8,428	6,134	56,950
2034	9,326	0	8,266	25,638	8,614	6,473	58,317
2035	9,392	0	7,213	27,514	8,800	6,781	59,701

ENERGY MIX %							
	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2020	23.7%	16.9%	28.4%	12.2%	15.5%	3.3%	100.0%
2021	23.5%	16.9%	28.8%	12.1%	15.4%	3.2%	100.0%
2022	22.8%	16.6%	27.6%	14.4%	15.5%	3.2%	100.0%
2023	22.2%	16.1%	26.2%	16.9%	15.5%	3.1%	100.0%
2024	21.3%	15.5%	26.6%	18.2%	15.4%	3.1%	100.0%
2025	20.8%	12.6%	23.9%	23.3%	15.3%	4.0%	100.0%
2026	19.9%	11.3%	23.6%	25.3%	15.3%	4.6%	100.0%
2027	19.6%	10.8%	21.9%	27.6%	15.2%	4.9%	100.0%
2028	18.8%	10.4%	21.4%	29.3%	15.1%	5.0%	100.0%
2029	18.4%	10.1%	18.5%	31.4%	15.0%	6.5%	100.0%
2030	17.6%	9.8%	18.6%	32.6%	14.9%	6.4%	100.0%
2031	17.3%	4.3%	16.3%	38.1%	14.8%	9.2%	100.0%
2032	16.7%	0.0%	17.4%	40.4%	14.8%	10.6%	100.0%
2033	16.5%	0.0%	15.6%	42.4%	14.8%	10.8%	100.0%
2034	16.0%	0.0%	14.2%	44.0%	14.8%	11.1%	100.0%
2035	15.7%	0.0%	12.1%	46.1%	14.7%	11.4%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.
2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.
3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(A)(3): ACCELERATE PORTFOLIO L&R AND ENERGY MIX

	Accelerate Portfolio - Loads & Resources - MW Energy Contribution at Peak																
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	**Load Requirements**																
2	APS Peak Demand	7,470	7,650	7,893	8,140	8,390	8,647	8,904	9,165	9,430	9,701	9,972	10,254	10,502	10,754	11,010	11,271
3	Reserve Requirements	1,026	1,113	1,136	1,167	1,193	1,224	1,251	1,278	1,306	1,333	1,362	1,400	1,427	1,453	1,482	1,510
4	**Total Load Requirements**	8,496	8,763	9,029	9,307	9,583	9,871	10,155	10,443	10,736	11,034	11,335	11,653	11,928	12,207	12,492	12,780
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
7	Coal	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	0	0	0	0	0
8	Natural Gas	5,225	5,239	5,239	5,194	5,194	5,194	4,629	4,059	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596
9	Combined Cycle	1,860	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891
10	Combustion / Steam Turbines	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545
11	PacifiCorp Seasonal Exchange	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	1,135	1,598	1,598	1,598	1,598	1,598	1,033	463	0	0	0	0	0	0	0	0
13	Market / Call Options / Hedges /AG-X	205	205	205	160	160	160	160	160	160	160	160	160	160	160	160	160
14	Renewable Energy	485	487	481	474	468	462	445	433	425	409	400	394	389	365	367	360
15	Distributed Energy	8	8	8	9	9	9	9	9	9	9	9	9	9	8	8	8
16	Solar	395	397	391	397	391	385	367	373	366	350	351	345	340	320	322	316
17	Wind	55	55	55	55	55	55	55	37	37	37	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
19	B omass/Biogas	16	16	16	3	3	3	3	3	3	3	3	3	3	0	0	0
20	Energy Storage	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	Microgr d	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
22	**Total Existing Resources**	8,245	8,261	8,257	8,205	8,198	7,806	7,223	6,641	6,171	6,154	6,145	5,169	5,165	5,140	5,142	5,135
23	**Customer Resources**																
24	Future Energy Efficiency	105	189	274	357	439	486	567	644	726	814	890	922	991	1,064	1,133	1,207
25	Future Distributed Energy	4	8	12	18	26	39	53	71	90	110	132	154	175	191	210	225
26	Demand Response (Future & Existing)	21	62	75	87	100	137	149	162	174	237	249	287	299	337	349	387
27	**Total Customer Resources**	130	259	361	463	564	661	769	877	990	1,160	1,271	1,363	1,464	1,592	1,692	1,818
28	**Future Resources**																
29	Natural Gas	150	237	134	25	12	0	0	0	0	0	0	0	0	0	0	0
30	Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Short-Term Market Purchases	150	237	134	25	12	0	0	0	0	0	0	0	0	0	0	0
33	Renewable Energy	0	0	64	178	175	267	261	288	353	427	419	557	543	598	575	630
34	Wind	0	0	64	153	150	242	236	263	328	402	394	532	518	573	550	605
35	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	B o/Geothermal	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25	25
37	PVS (PV + BESS)	0	0	98	193	393	918	1,596	2,132	2,598	2,661	2,817	3,293	3,497	3,658	3,840	3,994
38	Energy Storage	0	0	109	238	236	235	333	514	703	699	684	1,275	1,291	1,239	1,258	1,202
39	Microgr d	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
40	**Total Future Resources**	150	243	411	640	821	1,427	2,197	2,940	3,659	3,794	3,927	5,132	5,338	5,501	5,679	5,833
41	**TOTAL RESOURCES**	**8,524**	**8,763**	**9,029**	**9,307**	**9,583**	**9,894**	**10,189**	**10,457**	**10,820**	**11,108**	**11,343**	**11,663**	**11,966**	**12,233**	**12,514**	**12,787**

ATTACHMENT F.1(A)(3): ACCELERATE PORTFOLIO L&R AND ENERGY MIX (CONTINUED)

Energy Mix - Accelerate Portfolio

ENERGY (GWH)	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2020	9,149	6,532	10,966	4,720	6,005	1,254	38,625
2021	9,411	6,795	11,580	4,841	6,191	1,294	40,112
2022	9,344	6,801	11,289	5,889	6,378	1,333	41,034
2023	9,411	6,809	10,985	7,281	6,564	1,300	42,350
2024	9,335	6,793	11,496	8,114	6,750	1,346	43,834
2025	9,411	5,710	10,887	10,490	6,937	1,837	45,272
2026	9,289	5,257	9,712	13,137	7,123	2,199	46,718
2027	9,393	5,178	8,414	15,336	7,309	2,684	48,315
2028	9,353	5,178	8,259	16,701	7,496	2,909	49,897
2029	9,392	5,178	6,003	19,375	7,682	3,839	51,470
2030	9,290	5,173	7,372	19,546	7,869	3,865	53,114
2031	9,393	2,324	5,349	24,412	8,055	5,264	54,797
2032	9,317	0	5,400	27,365	8,241	5,967	56,290
2033	9,393	0	4,578	29,136	8,428	6,084	57,618
2034	9,326	0	3,944	30,816	8,614	6,334	59,035
2035	9,392	0	3,338	32,316	8,800	6,575	60,422

ENERGY MIX %	Nuclear	Coal	Gas	Renew	DSM	Purchase	TOT
2020	23.7%	16.9%	28.4%	12.2%	15.5%	3.2%	100.0%
2021	23.5%	16.9%	28.9%	12.1%	15.4%	3.2%	100.0%
2022	22.8%	16.6%	27.5%	14.4%	15.5%	3.2%	100.0%
2023	22.2%	16.1%	25.9%	17.2%	15.5%	3.1%	100.0%
2024	21.3%	15.5%	26.2%	18.5%	15.4%	3.1%	100.0%
2025	20.8%	12.6%	24.0%	23.2%	15.3%	4.1%	100.0%
2026	19.9%	11.3%	20.8%	28.1%	15.2%	4.7%	100.0%
2027	19.4%	10.7%	17.4%	31.7%	15.1%	5.6%	100.0%
2028	18.7%	10.4%	16.6%	33.5%	15.0%	5.8%	100.0%
2029	18.2%	10.1%	11.7%	37.6%	14.9%	7.5%	100.0%
2030	17.5%	9.7%	13.9%	36.8%	14.8%	7.3%	100.0%
2031	17.1%	4.2%	9.8%	44.6%	14.7%	9.6%	100.0%
2032	16.6%	0.0%	9.6%	48.6%	14.6%	10.6%	100.0%
2033	16.3%	0.0%	7.9%	50.6%	14.6%	10.6%	100.0%
2034	15.8%	0.0%	6.7%	52.2%	14.6%	10.7%	100.0%
2035	15.5%	0.0%	5.5%	53.5%	14.6%	10.9%	100.0%

1) Renew includes DE installed since 2008. EE includes energy beginning in 2005.

2) Total energy assumes energy generated or purchased (including line losses) to meet APS customer electric energy requirements prior to the impact of Energy Efficiency (EE) and Distributed Energy programs plus resale for long term wholesale contracts.

3) Percent of EE mix was calculated as a percentage of total energy in current calendar year. This calculation differs from the calculation for the EE Standard which is based upon cumulative annual EE energy savings by the end of each calendar year as a percentage of prior calendar year retail energy sales.

ATTACHMENT F.1(B): REVENUE REQUIREMENTS FOR BRIDGE, SHIFT, AND ACCELERATE PORTFOLIOS

Total Revenue Requirements ($Millions)			
	PATH 1. BRIDGE PORTFOLIO	PATH 2. SHIFT PORTFOLIO	PATH 3. ACCELERATE PORTFOLIO
2020	2,161	2,161	2,161
2021	2,371	2,370	2,371
2022	2,404	2,403	2,404
2023	2,511	2,511	2,520
2024	2,607	2,605	2,624
2025	2,965	2,966	2,927
2026	3,017	3,017	2,982
2027	3,123	3,127	3,177
2028	3,281	3,313	3,551
2029	3,342	3,392	3,699
2030	3,527	3,561	3,915
2031	3,491	3,565	4,035
2032	3,521	3,642	4,202
2033	3,643	3,794	4,422
2034	3,707	3,902	4,572
2035	3,827	4,074	4,788
CPW@7.50%			
(2020-2035)	26,593	26,924	28,442

ATTACHMENT F.1(B)(1): ANNUAL AVERAGE SYSTEM COST

Annual Average System Cost ($/MWh)			
	PATH 1. BRIDGE PORTFOLIO	PATH 2. SHIFT PORTFOLIO	PATH 3. ACCELERATE PORTFOLIO
2020	71.0	70.9	70.9
2021	75.8	75.8	75.8
2022	74.4	74.4	74.4
2023	75.4	75.5	75.7
2024	76.1	76.0	76.6
2025	84.2	84.2	83.1
2026	83.3	83.3	82.3
2027	83.9	84.0	85.4
2028	85.8	86.6	92.8
2029	85.1	86.3	94.2
2030	87.5	88.3	97.1
2031	84.4	86.2	97.5
2032	83.4	86.3	99.5
2033	84.7	88.2	102.8
2034	84.6	89.0	104.3
2035	85.7	91.2	107.2

ATTACHMENT F.1(B)(2): CUMULATIVE CAPITAL SPENDING

Cumulative Capital Spending - Existing and New Generation Plus Incremental Transmission			
	PATH 1. BRIDGE PORTFOLIO	PATH 2. SHIFT PORTFOLIO	PATH 3. ACCELERATE PORTFOLIO
2020	365.0	365.0	365.0
2021	1,026.7	1,026.7	1,020.3
2022	1,730.9	1,730.9	1,671.5
2023	2,538.0	2,538.0	2,261.3
2024	4,015.7	4,014.7	3,462.8
2025	5,543.3	5,512.5	5,320.3
2026	6,482.4	6,398.9	7,612.0
2027	7,479.3	7,673.1	10,205.6
2028	8,605.6	9,157.3	12,443.8
2029	9,756.7	10,096.8	13,768.3
2030	11,464.5	12,082.8	16,540.1
2031	13,234.8	14,655.4	20,019.3
2032	14,386.1	16,163.4	22,153.6
2033	15,522.2	17,647.7	24,170.2
2034	16,916.1	19,505.4	26,521.8
2035	17,929.2	20,822.2	28,114.2

ATTACHMENT F.1(B)(3): ANNUAL NATURAL GAS BURNS

Annual Natural Gas Burns (BCF)			
	PATH 1. BRIDGE PORTFOLIO	PATH 2. SHIFT PORTFOLIO	PATH 3. ACCELERATE PORTFOLIO
2020	82.85	82.73	82.79
2021	88.35	87.75	88.03
2022	83.82	83.76	83.66
2023	82.16	82.15	81.22
2024	89.46	89.40	88.29
2025	84.39	84.69	85.22
2026	82.19	82.21	74.13
2027	79.40	78.51	65.00
2028	91.13	85.47	70.60
2029	76.36	70.04	46.71
2030	79.81	77.99	63.87
2031	78.05	64.73	40.52
2032	88.53	71.91	42.51
2033	82.51	65.36	36.12
2034	80.83	61.56	31.70
2035	74.04	53.90	27.27

ATTACHMENT F.1(B)(4): ANNUAL CO_2 EMISSIONS

Annual CO2 Emissions (Metric Tons)			
	PATH 1. BRIDGE PORTFOLIO	PATH 2. SHIFT PORTFOLIO	PATH 3. ACCELERATE PORTFOLIO
2020	11,141,601	11,135,430	11,137,404
2021	11,693,956	11,671,846	11,686,937
2022	11,416,682	11,415,980	11,419,284
2023	11,241,797	11,244,912	11,190,923
2024	11,635,912	11,634,389	11,570,915
2025	10,502,108	10,517,524	10,549,531
2026	9,979,427	9,978,570	9,556,528
2027	9,777,875	9,714,361	9,075,484
2028	10,438,139	10,094,167	9,369,928
2029	9,621,645	9,236,856	8,053,675
2030	9,798,438	9,691,819	8,945,773
2031	7,264,548	6,508,295	5,288,680
2032	5,859,708	4,916,147	3,363,127
2033	5,537,823	4,524,933	2,934,025
2034	5,509,549	4,345,778	2,688,898
2035	5,087,241	3,839,000	2,333,962

ATTACHMENT F.1(B)(5): ANNUAL WATER USE

Annual Water Use (Acre-Feet)			
	PATH 1. BRIDGE PORTFOLIO	PATH 2. SHIFT PORTFOLIO	PATH 3. ACCELERATE PORTFOLIO
2020	49,545.1	49,519.2	49,519.8
2021	52,493.3	52,459.2	52,485.0
2022	52,130.2	52,133.1	52,126.8
2023	52,007.7	52,004.4	52,135.9
2024	52,260.3	52,273.4	52,517.8
2025	48,082.7	48,103.9	48,583.3
2026	46,633.8	46,651.6	45,846.0
2027	46,495.0	46,369.7	44,916.5
2028	46,734.1	46,245.6	44,462.6
2029	45,726.5	45,305.5	42,475.4
2030	45,154.3	45,179.2	43,134.9
2031	40,524.1	39,559.2	36,783.5
2032	37,520.6	36,066.8	32,489.3
2033	37,053.4	35,365.4	31,698.5
2034	36,698.4	34,670.6	30,922.2
2035	35,968.8	33,642.8	30,241.3

ATTACHMENT F.9(B)(1): BRIDGE PORTFOLIO - LOADS & RESOURCES FORECAST

	Bridge Portfolio - Loads & Resources - MW Energy Contribution at Peak																
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	**Load Requirements**																
2	APS Peak Demand	7,470	7,650	7,893	8,140	8,390	8,647	8,904	9,165	9,430	9,701	9,972	10,254	10,502	10,754	11,010	11,271
3	Reserve Requirements	1,026	1,113	1,136	1,167	1,193	1,224	1,251	1,278	1,306	1,333	1,362	1,400	1,427	1,453	1,482	1,510
4	**Total Load Requirements**	8,496	8,763	9,029	9,307	9,583	9,871	10,155	10,443	10,736	11,034	11,335	11,653	11,928	12,207	12,492	12,780
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
7	Coal	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	0	0	0	0	0
8	Natural Gas	5,225	5,239	5,239	5,194	5,194	5,194	4,629	4,059	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596
9	Combined Cycle	1,860	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891
10	Combustion / Steam Turbines	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545
11	PacifiCorp Seasonal Exchange	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	1,135	1,598	1,598	1,598	1,598	1,598	1,033	463	0	0	0	0	0	0	0	0
13	Market / Call Options / Hedges /AG-1	205	205	205	160	160	160	160	160	160	160	160	160	160	160	160	160
14	Renewable Energy	485	487	481	474	468	462	445	433	425	409	400	394	389	365	367	360
15	Distributed Energy	8	8	8	9	9	9	9	9	9	9	9	9	9	8	8	8
16	Solar	395	397	391	397	391	385	367	373	366	350	351	345	340	320	322	316
17	Wind	55	55	55	55	55	55	55	37	37	37	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	3	3	3	3	3	3	3	3	3	3	0	0	0
20	Energy Storage	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	Microgr d	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
22	**Total Existing Resources**	8,245	8,261	8,257	8,205	8,198	7,806	7,223	6,641	6,171	6,154	6,146	5,169	5,165	5,140	5,143	5,136
23	**Customer Resources**																
24	Future Energy Eff ciency	105	189	274	357	439	486	567	644	726	814	890	922	991	1,064	1,133	1,207
25	Future Distributed Energy	4	8	12	18	26	39	53	71	90	110	132	154	175	191	210	225
26	Demand Response (Future & Existing)	21	62	75	87	100	137	149	162	174	212	224	262	274	312	324	337
27	**Total Customer Resources**	130	259	361	463	564	661	769	877	990	1,135	1,246	1,338	1,439	1,567	1,667	1,768
28	**Future Resources**																
29	Natural Gas	150	237	134	50	37	0	565	1,135	1,497	1,497	1,497	1,859	1,859	1,859	1,859	1,859
30	Combined Cycle	0	0	0	0	0	0	565	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135
31	Combustion Turbines	0	0	0	0	0	0	0	0	362	362	362	724	724	724	724	724
32	Short-Term Market Purchases	150	237	134	50	37	0	0	0	0	0	0	0	0	0	0	0
33	Renewable Energy	0	0	64	153	150	279	272	351	343	399	475	544	532	585	561	619
34	Wind	0	0	64	153	150	279	272	351	343	399	475	544	532	585	561	619
35	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Bio/Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	PVS (PV + ESS)	0	0	98	193	393	863	1,077	1,222	1,487	1,606	1,774	2,150	2,338	2,452	2,647	2,805
38	Energy Storage	0	0	109	238	236	235	237	236	239	242	244	516	511	507	498	486
39	Microgr d	0	6	6	6	6	31	31	56	56	56	56	106	106	131	131	131
40	**Total Future Resources**	150	243	411	640	821	1,408	2,182	3,000	3,622	3,800	4,045	5,175	5,346	5,534	5,697	5,900
41	**TOTAL RESOURCES**	**8,524**	**8,763**	**9,029**	**9,307**	**9,583**	**9,875**	**10,174**	**10,517**	**10,782**	**11,090**	**11,437**	**11,682**	**11,950**	**12,241**	**12,507**	**12,804**

ATTACHMENT F.9(B)(2): SHIFT PORTFOLIO - LOADS & RESOURCES FORECAST

Shift Portfolio - Loads & Resources - MW Energy Contribution at Peak																	
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	**Load Requirements**																
2	APS Peak Demand	7,470	7,650	7,893	8,140	8,390	8,647	8,904	9,165	9,430	9,701	9,972	10,254	10,502	10,754	11,010	11,271
3	Reserve Requirements	1,026	1,113	1,136	1,167	1,193	1,224	1,251	1,278	1,306	1,333	1,362	1,400	1,427	1,453	1,482	1,510
4	**Total Load Requirements**	8,496	8,763	9,029	9,307	9,583	9,871	10,155	10,443	10,736	11,034	11,335	11,653	11,928	12,207	12,492	12,780
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
7	Coal	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	0	0	0	0	0
8	Natural Gas	5,225	5,239	5,239	5,194	5,194	5,194	4,629	4,059	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596
9	Combined Cycle	1,860	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891
10	Combustion / Steam Turbines	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545
11	PacifiCorp Seasonal Exchange	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	1,135	1,598	1,598	1,598	1,598	1,598	1,033	463	0	0	0	0	0	0	0	0
13	Market / Call Options / Hedges /AG-1	205	205	205	160	160	160	160	160	160	160	160	160	160	160	160	160
14	Renewable Energy	485	487	481	474	468	462	445	433	425	409	400	394	389	365	367	360
15	Distributed Energy	8	8	8	9	9	9	9	9	9	9	9	9	9	8	8	8
16	Solar	395	397	391	397	391	385	367	373	366	350	351	345	340	320	322	316
17	Wind	55	55	55	55	55	55	55	37	37	37	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	3	3	3	3	3	3	3	3	3	3	0	0	0
20	Energy Storage	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	Microgr d	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
22	**Total Existing Resources**	8,245	8,261	8,257	8,205	8,198	7,806	7,223	6,641	6,171	6,154	6,146	5,169	5,165	5,140	5,143	5,136
23	**Customer Resources**																
24	Future Energy Eff ciency	105	189	274	357	439	486	567	644	726	814	890	922	991	1,064	1,133	1,207
25	Future Distributed Energy	4	8	12	18	26	39	53	71	90	110	132	154	175	191	210	225
26	Demand Response (Future & Existing)	21	62	75	87	100	137	149	162	174	237	249	287	299	337	349	362
27	**Total Customer Resources**	130	259	361	463	564	661	769	877	990	1,160	1,271	1,363	1,464	1,592	1,692	1,793
28	**Future Resources**																
29	Natural Gas	150	237	134	50	12	0	565	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135
30	Combined Cycle	0	0	0	0	0	0	565	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135
31	Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Short-Term Market Purchases	150	237	134	50	12	0	0	0	0	0	0	0	0	0	0	0
33	Renewable Energy	0	0	64	153	150	279	272	351	343	383	460	577	562	611	582	647
34	Wind	0	0	64	153	150	279	272	351	343	383	460	577	562	611	582	647
35	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Bio/Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	PVS (PV + ESS)	0	0	98	193	393	871	1,092	1,263	1,867	1,959	2,024	2,575	2,795	2,941	3,172	3,334
38	Energy Storage	0	0	109	238	236	235	237	236	238	241	243	708	690	673	649	620
39	Microgr d	0	6	6	6	31	31	31	31	31	31	56	131	131	131	131	131
40	**Total Future Resources**	150	243	411	640	821	1,416	2,197	3,016	3,614	3,749	3,918	5,125	5,313	5,491	5,670	5,867
41	**TOTAL RESOURCES**	**8,524**	**8,763**	**9,029**	**9,307**	**9,583**	**9,882**	**10,189**	**10,533**	**10,775**	**11,064**	**11,335**	**11,657**	**11,942**	**12,222**	**12,505**	**12,796**

ATTACHMENT F.9(B)(3): ACCELERATE PORTFOLIO - LOADS & RESOURCES FORECAST

	Accelerate Portfolio - Loads & Resources - MW Energy Contribution at Peak																
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	**Load Requirements**																
2	APS Peak Demand	7,470	7,650	7,893	8,140	8,390	8,647	8,904	9,165	9,430	9,701	9,972	10,254	10,502	10,754	11,010	11,271
3	Reserve Requirements	1,026	1,113	1,136	1,167	1,193	1,224	1,251	1,278	1,306	1,333	1,362	1,400	1,427	1,453	1,482	1,510
4	**Total Load Requirements**	8,496	8,763	9,029	9,307	9,583	9,871	10,155	10,443	10,736	11,034	11,335	11,653	11,928	12,207	12,492	12,780
5	**Existing Resources**																
6	Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
7	Coal	1,357	1,357	1,357	1,357	1,357	970	970	970	970	970	970	0	0	0	0	0
8	Natural Gas	5,225	5,239	5,239	5,194	5,194	5,194	4,629	4,059	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596
9	Combined Cycle	1,860	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891	1,891
10	Combustion / Steam Turbines	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545	1,545
11	PacifiCorp Seasonal Exchange	480	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Tolling Agreements	1,135	1,598	1,598	1,598	1,598	1,598	1,033	463	0	0	0	0	0	0	0	0
13	Market / Call Options / Hedges /AG-1	205	205	205	160	160	160	160	160	160	160	160	160	160	160	160	160
14	Renewable Energy	485	487	481	474	468	462	445	433	425	409	400	394	389	365	367	360
15	Distributed Energy	8	8	8	9	9	9	9	9	9	9	9	9	9	8	8	8
16	Solar	395	397	391	397	391	385	367	373	366	350	351	345	340	320	322	316
17	Wind	55	55	55	55	55	55	55	37	37	37	37	37	37	37	37	37
18	Geothermal	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0
19	Biomass/Biogas	16	16	16	3	3	3	3	3	3	3	3	3	3	0	0	0
20	Energy Storage	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	Microgr d	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
22	**Total Existing Resources**	8,245	8,261	8,257	8,205	8,198	7,806	7,223	6,641	6,171	6,154	6,145	5,169	5,165	5,140	5,142	5,135
23	**Customer Resources**																
24	Future Energy Eff ciency	105	189	274	357	439	486	567	644	726	814	890	922	991	1,064	1,133	1,207
25	Future Distributed Energy	4	8	12	18	26	39	53	71	90	110	132	154	175	191	210	225
26	Demand Response (Future & Existing)	21	62	75	87	100	137	149	162	174	237	249	287	299	337	349	387
27	**Total Customer Resources**	130	259	361	463	564	661	769	877	990	1,160	1,271	1,363	1,464	1,592	1,692	1,818
28	**Future Resources**																
29	Natural Gas	150	237	134	25	12	0	0	0	0	0	0	0	0	0	0	0
30	Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Combustion Turbines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Short-Term Market Purchases	150	237	134	25	12	0	0	0	0	0	0	0	0	0	0	0
33	Renewable Energy	0	0	64	178	175	267	261	288	353	427	419	557	543	598	575	630
34	Wind	0	0	64	153	150	242	236	263	328	402	394	532	518	573	550	605
35	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Bio/Geothermal	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25	25
37	PVS (PV + ESS)	0	0	98	193	393	918	1,596	2,132	2,598	2,661	2,817	3,293	3,497	3,658	3,840	3,994
38	Energy Storage	0	0	109	238	236	235	333	514	703	699	684	1,275	1,291	1,239	1,258	1,202
39	Microgr d	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
40	**Total Future Resources**	150	243	411	640	821	1,427	2,197	2,940	3,659	3,794	3,927	5,132	5,338	5,501	5,679	5,833
41	**TOTAL RESOURCES**	**8,524**	**8,763**	**9,029**	**9,307**	**9,583**	**9,894**	**10,189**	**10,457**	**10,820**	**11,108**	**11,343**	**11,663**	**11,966**	**12,233**	**12,514**	**12,787**

ACRONYMNS & GLOSSARY

TABLE OF ACRONYMS AND ABBREVIATIONS (CONTINUED)

4FRI	Four Forest Restoration Initiative
AC	Alternating Current
ACC	Arizona Corporation Commission
ACDC	APS Cyber Defense Center
ACE	Affordable Clean Energy
ADEQ	Arizona Department of Environmental Quality
ADMS	Advanced Distribution Management System
ADWR	Arizona Department of Water Resources
AESP	Association of Energy Services Professionals
AF	Acre Feet
AFB	Air Force Base
AFUDC	Allowance for Funds Used During Construction
AGS	Arizona Gas Storage
AMA	Active Management Area
AMI	Advanced Metering Infrastructure
APP	Aquifer Protection Permit
APS	Arizona Public Service
ATC	Available Transfer Capability
BA	Balancing Authority
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BCF	Billion Cubic Feet
BES	Bulk Electric System
BESS	Battery Energy Storage System
BNEF	Bloomberg New Energy Finance
BOR	Bureau of Reclamation
BTA	Biennial Transmission Assessment
BTU	British Thermal Unit
C&I	Commercial and Industrial
CAA	Clean Air Act
CAES	Compressed Air Energy Storage
CAFO	Concentrating Animal Feeding Operation
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CAP	Central Arizona Project
CC	Combined Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture & Sequestration/ Carbon Capture & Storage
CDP	Climate Disclosure Project
CEC	Certificate of Environmental Compatibility
CERCLA	Comprehensive Environmental Response Compensation & Liability Act

CFI	Communicating Fault Indicators
CO	Carbon Monoxide
CO2	Carbon Dioxide
Commission	Arizona Corporation Commission
Committee	Arizona Power Plant and Line Siting Committee
Company	Arizona Public Service
COVID-19	Coronavirus Disease 2019
CPP	Clean Power Plan
CPP-RES	Critical Peak Pricing for Residential Customers
CSP	Concentrating Solar Power
CT	Combustion Turbine
CWA	Clean Water Act
D.C. Circuit	U.S. Court of Appeals for the District of Columbia Circuit
DA	Distribution Automation
DAM	Distribution Asset Monitoring
DC	Direct Current
DE	Distributed Energy
DER	Distributed Energy Resources
DMS	Distribution Management System
DOE	U.S. Department of Energy
DR	Demand Response
DRESLM	Demand Response, Energy Storage, Load Management program
DSCADA	Distribution Supervisory Control and Data Acquisition
DSM	Demand Side Management
E-20	Time-of-use for Religious Houses of Worship
E3	Energy and Environmental Economics, Inc.
E-32	Extra-small, Small, Medium, Large Businesses
E-35	Extra Large Time-of-use Business
EA	Environmental Assessment
EAB	Environmental Appeals Board
ECT-1R	Combined Advantage (9am-9pm)
ECT-2	Combined Advantage (Noon-7pm)
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EES	Energy Efficiency Standard
EGU	Electric Generating Units
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIS	Environmental Impact Statement
ELG	Effluent Limitations Guidelines
EMS	Energy Management System

TABLE OF ACRONYMS AND ABBREVIATIONS (CONTINUED)

EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EPNG	El Paso Natural Gas
EPRI	Electric Power Research Institute
ESA	Endangered Species Act
ESG	Environment, Social and Governance
ESS	Energy Storage Systems
ET-1	Time Advantage (9am-9pm)
ET-2	Time Advantage (Noon-7pm)
ET-SP	Time Advantage Super Peak
EV	Electric Vehicle
FC	Four Corners Power Plant
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FONSI	Finding of No Significant Impact
Genset	Generator Set
GHG	Greenhouse Gas
GRIC	Gila River Indian Community
GS-Schools	General Service Medium and Large Time-of-use for Elementary and Secondary Schools
GUAC	Groundwater Users Advisory Council
GW	Gigawatt
GWh	Gigawatt-Hours
HAPs	Hazardous Air Pollutants
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IFES	Feeder-scale battery storage
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
IVVC	Integrated Volt/VAR Control
KAF	Thousand Acre Feet
KM	Kinder Morgan
KV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-Hour
LAER	Lowest Achievable Emission Rate
LCOE	Levelized Cost of Electricity
LED	Light Emitting Diode
LFP	Lithium Ion Phosphate

Li-Ion	Lithium Ion
LNB	Low Nox Burners
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
MACT	Maximum Achievable Control Technology
MAIFI	Momentary Average Interruption Frequency Index
MATS	Mercury and Air Toxics Standard
MCAQD	Maricopa County Air Quality Department
MCAS	Marine Corps Air Station
MER	Measurement and Evaluation Research
MMBtu	Million British Thermal Units
MOD-29	Rated System Path Methodology
MOD-30	Flowgate Methodology
MTU	Metric Ton of Uranium
MW	Megawatt
MWh	Megawatt-Hour
N2	Nitrogen
NAAQS	National Ambient Air Quality Standards
NaS	Sodium-sulfur
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NGS	Navajo Generating Station
NMC	Nickel Manganese Cobalt
NNSR	Nonattainment New Source Review
NOx	Nitrogen Oxide
NP	Network Protections
NPV	Net Present Value
NRC	Nuclear Regulatory C
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operation & Maintenance
OASIS	Open Access Same-Time Information System
OMP	Ocotillo Modernization Project
OMS	Outage Management System
PAC	Program Administrator Cost
PC	Participant Cost
PCB	Polychlorinated Biphenyls
PLMA	Peak Load Management Alliance
PM	Particulate Matter
PMUs	Phasor Measurement Units
PPA	Purchased Power Agreement
PPB	Parts per Billion
PPH	People Per Household
PSD	Prevention of Significant Deterioration

TABLE OF ACRONYMS AND ABBREVIATIONS (CONTINUED)

PSIA	Pounds Per Square Inch Absolute
PTC	Production Tax Credit
PTR	Peak Time Rebate
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PVNGS	Palo Verde Nuclear Generating Station
PVS	Photovoltaic with Storage
PVWRF	Palo Verde Water Reclamation Facility
PWR	Pressurized Water Reactor
QF	Qualified Facility
R-2	Saver Choice Plus
R-3	Saver Choice Max
RC	Reliability Coordinator
RCP	Resource Comparison Proxy
RCRA+I36: JI36:J50	Resource Conservation & Recovery Act
RE	Renewable Energy Resource
Redox	Reduction and Oxidation
RES	Renewable Energy Standard
REST	Renewable Energy Standard Tariff
RFP	Request for Proposal
RIM	Ratepayer Impact Measure
ROP	NERC's Rules of Procedure
RPS	Renewable Portfolio Standard
R-TECH	Saver Choice Tech Pilot
R-TOU-E	Saver Choice
RTP	Renewable Transmission Projects
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAT	Single-Axis Tracking
SC	Societal Cost
SCE	Southern California Edison Company
SCR	Selective Catalytic Reduction
SEPA	Smart Electric Power Alliance
SF6	Sulfur Hexafluoride
SHM	Substation Health Monitoring
SIP	State Implementation Plan
SMR	Small Modular Reactor
SO2	Sulfur Dioxide
SOC	State-Of-Charge
SRP	Salt River Project Agricultural Improvement and Power District
SRSG	Southwest Reserve Sharing Group
SWAT	Southwest Area Transmission
TEP	Tucson Electric Power
TO	Transmission Owner

TOP	Transmission Operator
TOU	Time of Use
TRC	Total Resource Cost
TSCA	Toxic Substances Control Act
USBR	United States Bureau of Reclamation
USGS	U.S. Geological Survey
VER	Variable Energy Resources
VOC	Volatile Organic Compounds
WEC	World Energy Council
WECC	Western Electricity Coordinating Council
WIIN	Water Infrastructure Improvements
ZLD	Zero Liquid Discharge

GLOSSARY

2020 Resource Plan (or 2020 Integrated Resource Plan or IRP)	Represents the documented process APS undertakes to select a number of alternative energy resource portfolios for the 2020-2035 period based upon a wide range of supply- and demand-side options.
4FRI	***See*** Four Forest Restoration Initiative
ABB (Formerly Ventyx)	The company that produces the modeling tool, Strategist, used for this IRP.
Acre-Foot	The volume of water that will cover an area of one acre to a depth of one foot. One acre foot equals approximately 325,851 gallons.
Action Plan	Material actions anticipated to occur during the Action Plan Period.
Action Plan Period	For the purposes of this filing, the timeframe of 2020-2024.
Activated Carbon Injection System (ACI)	An engineered mercury control system from which powdered activated carbon (PAC) is pneumatically injected from a storage silo into the flue gas ductwork of a coal-fired power plant or industrial boiler. The PAC adsorbs the vaporized mercury from the flue gas and is then collected with the fly ash in the facility's particulate collection device.[1]
Aquifer Protection Permit Program in Arizona	An ADEQ program designed to protect the quality of Arizona drinking water. Includes two key requirements: (1) meet Aquifer Water Quality Standards at the Point of Compliance; and (2) demonstrate Best Available Demonstrated Control Technology.
Arizona Administrative Code (A.A.C.)	The official compilation of rules that govern the state of Arizona's agencies, boards, and commissions.
Arizona Corporation Commission (ACC or Commission)	The Arizona Corporation Commission is comprised of five publically-elected persons who have full power to make reasonable rules, regulations and orders by which public service corporations shall be governed in doing business within the state of Arizona.
Arizona Department of Environmental Quality (ADEQ)	Administers a variety of programs to improve the health and welfare of citizens and ensure the quality of Arizona's air, land, and water resources meet healthful, regulatory standards.
Aurora	Energy Exemplar's production simulation software for forecast modeling and analysis. AURORA, which is a production cost model that optimizes commitment and dispatch of resources against hourly load, has enhanced storage logic that facilitates efficient integration of energy storage on systems with large renewable penetrations.
Auxiliary Load	The load that serves the power plant itself. Under normal circumstances, the auxiliary load is served by the production at the plant. If the plant is not producing power, then it is necessary for the grid to server the auxiliary load.
Baghouse	An air pollution abatement device that traps particulates (dust) by forcing gas streams through large filter bags, usually made of fiberglass or other synthetic fabrics and coatings.
Baseload Plant	An electric generating plant devoted to the production of electricity on a relatively continuous basis. Baseload plants are typically operated for the majority of the hours during a given year and are taken off-line relatively infrequently. Baseload plants usually have a low variable production cost relative to other production facilities available to the system.

[1] http://www.adaes.com/mercury/acis/

Best Available Retrofit Technology (BART)	Under the Clean Air Act, states must require the installation of the best retrofit emission controls available as part of state strategies for meeting the regional haze rule. The BART requirement applies to facilities built between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollution.
Biogas	A mixture of gases produced by the breakdown of organic matter in the absence of oxygen (anaerobically), primarily consisting of methane and carbon dioxide. Biogas, which can be produced from raw materials such as agricultural waste, manure, municipal waste or landfill, is used a fuel for the production of electric power.
Biomass	Organic non-fossil material of biological origin constituting a renewable energy source that can be either processed into biofuel or burned directly to produce steam or electricity.
British Thermal Unit (Btu)	Used to describe the heat content of fuel. The price of fuel is typically expressed in terms of dollars per million Btu (or $/MMBtu).
Cap-and-Trade	An approach used to control emissions by providing economic incentives for achieving reductions. A central authority (usually a government or international body) sets a limit or cap on the amount that can be emitted. Companies or other groups are issued emission permits and are required to hold an equivalent number of allowances (or credits) which represent the right to emit a specific amount. The total amount of allowances cannot exceed the cap, limiting total emissions to that level. Companies that need to increase their emission allowances must buy credits from those that emit less. The transfer of allowances is referred to as a trade. In effect, the buyer is paying a charge for emitting, while the seller is being rewarded for having reduced emissions by more than was required.
Capacity	The maximum amount of electricity produced or extracted from a resource in any given moment. Capacity is usually measured in units of megawatts. It should be noted that most resources are not operated at their maximum capacity rating during all hours. ***See*** *Capacity Factor*
Capacity Factor	A value used to express the average output level of a resource over a given period of time. Capacity factor is expressed as a percentage of the maximum possible output of the resource had operated at its maximum capacity rating for all hours during the period. For example, a generating facility which operates at an average of 60% of its maximum capacity over a measured period has a capacity factor of 60% for that period.
Capacity Value	A resource's ability to reliably serve load during the top 90 load hours of the year. APS calculates capacity value by dividing the average net capacity of the resource during APS's top 90 load hours by the resource's maximum hourly capacity.
Carbon Capture & Sequestration/Storage (CCS)	A technology under development to limit emissions of carbon by capturing and storing it away from the atmosphere.
Carbon Dioxide (CO2)	A naturally occurring gas, and also a by-product of burning fossil fuels and biomass, as well as land-use changes and other industrial processes. It is the principal greenhouse gas that affects the Earth's radiative balance. ***See*** *Greenhouse Gas, Emissions*

GLOSSARY (CONTINUED)

Carbon Intensity	The amount of carbon dioxide produced for every unit of energy. For the purposes of this IRP, carbon intensity will be measured in metric tons of carbon dioxide per megawatt-hour.
Carbon Monoxide (CO)	A colorless, odorless, toxic gas produced by the incomplete combustion of carbon-containing substances. One of the major air pollutants, it is emitted in large quantities by exhaust of gasoline-powered vehicles.
Carrying Charges (or Carrying Costs)	Annual costs associated with investment in assets including depreciation, debt interest, equity return, income taxes, and property taxes.
Class-Based Hourly Load Models	Methods for identifying the hourly pattern of electricity demand for groups of customers with similar characteristics.
Clean Air Act (CAA)	The primary federal law enacted by the U.S. Congress to govern the regulation of emissions into the atmosphere on a national level. The primary responsibility for administering the CAA was given to EPA which develops and enforces regulations to protect the general public from exposure to airborne contaminants.
Clean Energy Commitment (CEC)	APS Clean Energy Commitment 1) By 2050, APS will deliver 100 percent clean, carbon–free and affordable electricity to our customers. 2) This goal includes a nearer–term 2030 target of 65 percent clean energy, with 45 percent of our generation portfolio coming from renewable energy. 3) APS will cease all coal–fired generation by 2031.
Coal Combustion Residual (CCR)	Referred to as coal ash, CCRs are currently considered exempt wastes under the Beville amendment to the Resource Conservation and Recovery Act (RCRA). They are residues from the combustion of coal in power plants and captured by pollution control technologies, such as scrubbers.
Coincident Peak	An individual customer's peak coincides with the system peak, meaning they are contributing to that peak hour.
Combined Cycle (CC)	Twin-stage natural gas-fired power plants that deliver higher fuel efficiency. In the first stage, a gaseous fuel source (natural gas, gaseous coal, etc.) is combusted in a gas turbine. The turbine is used to drive an electric generator. In the second stage, waste heat is captured from the gas turbine's hot exhaust gases in a heat recovery steam generator (HRSG). The steam that is produced in the HRSG is used to drive a steam turbine and produce additional electricity. This beneficial use of the residual heat content in the gas turbine's exhaust stream contributes to the excellent fuel efficiency of the combined cycle power plant.
Combustion Turbines (CT)	Also referred to as a simple cycle gas turbine, these electric generators operate on a principle similar to the engines on jet airplanes. Ambient air is compressed to high pressures in the compressor section of the machine. A gaseous fuel source is added to this compressed air and combusted in the combustor section. The resulting hot gases are then expanded through a turbine section that provides the driving force for both an electric generator and the compressor section.

GLOSSARY (CONTINUED)

Commercial Operation Date (COD)	The date when an operating utility formally declares a new generation resource to be available for the regular production of electricity.
Commodity Hedging Strategies	***See*** *Hedging*
Compact Fluorescent Lamp (CFL)	A type of fluorescent lamp. Compared to incandescent lamps giving the same amount of visible light, CFLs use less power and have a longer rated life.
Competitive Procurement Procedure	Any solicitation process initiated to meet APS energy requirements. The Competitive Procurement Process shall include, as appropriate, preparing and conducting the solicitation, bid evaluation and selection, and negotiating the definitive agreement(s), but shall not include management or implementation of such agreement(s) after their execution.
Concentrated Solar Power (CSP)	Technologies that concentrate solar energy to generate electricity. This class of solar technologies includes solar trough, power towers, dish stirling, and concentrating photovoltaics.
Conditional Demand Analysis (CDA)	Statistical approach that allocates total household electricity demand during a period into components associated with a particular electricity-using appliance or end-use.
Consumption (Energy Use)	The total amount of electricity consumed over a period of time, measured in megawatt-hours. Consumption varies from demand in that demand is the rate at which electricity is being used at any one given time.
Conventional Resources	Conventional generating resources include a broad class of technologies that use coal, nuclear, natural gas, or fuel oil to generate electricity. Generally, conventional resources are dispatchable.
Cooling Degree-day	A measure of how warm a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the base temperature (65 degrees) from the average of the day's high and low temperatures, with negative values set equal to zero. Each day's cooling degree-days are summed to create a cooling degree-day measure for a specified reference period. Cooling degree-days are used in energy analysis as an indicator of air conditioning energy requirements or use.
Critical Peak Pricing (CPP)	Time-of-use rate plan (also known as Peak Event Pricing) that provides an extremely high price signal during a limited number of hours on critical days (such as periods of high electrical demands, extreme temperatures, system outages, or other abnormal grid-related events).
Customer Average Interruption Duration Index (CAIDI)	The average outage duration for those customers experiencing an outage.

GLOSSARY (CONTINUED)

Customer Resources (or customer-sited resources)	Resource options which rely upon active participation by customers to produce either a reduction in energy consumption or peak demand. These customer-side resource programs include energy efficiency programs, demand response programs, and alternative rate schedules. Energy efficiency programs are directed at achieving reductions in customer energy consumption through more efficient equipment or improvements to a building's thermal envelope. Demand response programs generally target reductions during the highest usage periods of the year through special rate schedules (such as time-of-use prices), energy storage options, or other similar programs.
Day-Ahead Trader	Trader that engages in forward markets that cover a 24-hour period in advance of a given day.
Delivered Cost	Refers to the cost of power produced by a generating unit (or a purchased power contract) where the cost of delivering the electric power from the generating source to the load center (area of customer consumption) has also been included in the cost.
Demand	The rate at which electricity is being used at any given time, measured in megawatts. Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time.
Demand Response (DR)	Mechanisms designed to provide incentives to customers to reduce their load in response to high electric market prices or electric system reliability concerns. Demand response measures could include direct load control programs, such as cycling of air conditioner load, or customer-initiated load reductions. Price response programs include real-time pricing, dynamic pricing, critical peak pricing, time-of-use rates, and demand bidding or buyback programs.
Demand-Side Management (DSM)	The planning, implementation, and monitoring of utility activities designed to encourage residential and business customers to modify patterns of electricity usage, including the timing and level of electricity demand.
Discount Rate	An interest rate used to convert future cash flows to present values.
Dispatchable	Generating units (or purchased power contracts) whose rate of power production can be adjusted or varied based upon economic or other considerations. Different types of generating units have varying degrees of dispatchability either for technical or economic reasons.
Distributed Energy	A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid or the customer's electrical system. Distributed generation can serve as a primary or backup energy source and can use various technologies, including combustion turbines, reciprocating engines, fuel cells, wind generators, and solar photovoltaics.
Distribution	The delivery of energy to retail customers.
Dry Cooling	The typical steam power plant requires cooling water to improve overall cycle efficiency by returning the exhaust steam to a liquid state that can then be returned to the boiler to produce more steam. In a dry-cooled power plant, the exhaust steam is cooled by use of air-cooled condensers thereby eliminating the use of water from this portion of the power production process; however, the air-cooled condensers are more expensive and overall plant efficiency is reduced versus water-cooled plants.

GLOSSARY (CONTINUED)

DSM Implementation Plan	Annual filing required for compliance with the Arizona Corporation Commission's Electric Energy Efficiency Standards, codified at A.A.C. RI4-2-2401, which includes the implementation strategy APS will use to achieve compliance with the EE Standard.
Effluent	Wastewater, treated or untreated, that flows out of a treatment plant, sewer, or industrial outfall. Generally refers to wastes discharged into surface waters.
Electric Generating Units (EGU)	A solid fuel-fired steam generating unit that serves a generator who produces electricity for sale to the electric grid.
Emissions	Discharges into the atmosphere from stacks, other vents, and surface areas of commercial and industrial facilities; from residential chimneys; and from motor vehicle, locomotive, or aircraft exhaust.
Energy	The amount of electricity a resource outputs, or an end user consumes, in any given period of time. It is usually measured in units of kilowatt-hours, megawatt-hours, or gigawatt-hours.
Energy Efficiency	In the context of resource planning, energy efficiency refers to actions taken by consumers to reduce their overall consumption of electric energy. These reductions could be the result of installation of more efficient equipment, improvements to the thermal envelopes of structures, or behavioral changes. Energy efficiency improvements can be encouraged through utility-sponsored programs, mandated by building codes or other standards or simply implemented by the customer.
Energy Efficiency Standard (EES)	Requirement codified in A.A.C. R14-2-2404 to achieve an accumulated energy savings equivalent to 22% of retail sales by the year 2020.
Energy Exemplar	The company that produces the modeling tool, Aurora, used for this IRP.
Energy Mix	The percentage of each type of energy generated in a scenario or profile. Together, the percentages for each scenario add up to 100%.
Energy Savings	A reduction in the amount of electricity used by end users. In this IRP, it specifically refers to the reduction that is result of participation in energy efficiency programs and load management programs.
Environmental Protection Agency (EPA)	A governmental agency established in 1970 to research, monitor, and establish standards that protect human health and the environment. The EPA also has the authority to enforce regulations when necessary, although normally the states implement them.
Externalities	Occurs when an entity is engaged in an activity that creates harm or benefits for others as a byproduct, but that entity does not pay the costs of, or receive compensation for, the harm or benefits created. An example would be water use and water consumption.
Federal Energy Regulatory Commission (FERC)	A governmental agency that regulates the interstate transmission of natural gas, oil, and electricity and wholesale power transactions. FERC also regulates natural gas and hydropower projects.

Federal Poverty Guidelines	Issued each year in the Federal Register by the Department of Health and Human Services. The guidelines are a simplification of the poverty thresholds for use for administrative purposes — for instance, determining financial eligibility for certain federal programs.
Flexible Resource	Dispatchable generation resource capable of reaching full capacity in under an hour from cold start.
Force Majeure	Disruptions in service caused by natural disasters (earthquakes, hurricanes, floods, etc.); wars, riots, or other major upheaval; or, performance failures of parties outside the control of the contracting party.
Four Forest Restoration Initiative (4FRI)	The Arizona Four Forest Restoration Initiative focus has been to improve and sustain watershed health, improve wildlife habitat, conserve biodiversity, protect old-growth, reduce the risk of uncharacteristic wildland fire and promote the reintroduction of natural fire, and restore natural forest structure and function.
Fuel Cell	A device that converts chemical energy into electrical energy using a fuel. Fuel cells require a constant supply of fuel and oxygen for its chemical reaction unlike batteries where the chemicals react with each other to provide the electricity.
Genset	At its simplest, a generator set consists of an engine and an electric generator, which is used to produce electrical power. A diesel generation set provides fast-starting, backup power in the event of a grid disruption.
Geothermal	Energy produced below the Earth's crust in a layer of hot and molten rock called magma, heating nearby rock and water that has seeped deep into the Earth. At geothermal power plants, wells are drilled into the rock to more effectively capture the hot water and steam to be used to drive electric generators.
Greenhouse Gas (GHG)	A collection of gaseous substances, primarily consisting of carbon dioxide, methane, and nitrogen oxides, which have been shown to warm the earth's atmosphere by trapping solar radiation. Greenhouse gases also include chlorofluorocarbons, a group of chemicals used primarily in cooling systems and which are now either outlawed or severely restricted by most industrialized nations.
(Power or electric) Grid	An interconnected network of electric power transmission lines. The United States power grid, which covers most of the country as well as parts of Canada and Mexico, is made up the Eastern Interconnection, Western Interconnection, and Texas Interconnection. These networks include extra-high-voltage connections between individual utilities, which transfer electrical energy from one part of the network to another. The Interconnects distribute electricity in their respective areas via a network of smaller units that enable better management of power distribution.
Groundwater	Water that is held in soil or in rocks underground. Groundwater is distinct from surface water, which is water held in lakes and rivers.
Hazardous Air Pollutants (HAP)	Substances covered by air quality criteria, which may cause or contribute to illness or death.

GLOSSARY (CONTINUED)

Heat Rate	A measure of the amount of thermal energy required to produce a given amount of electric energy. It is usually expressed in British thermal units per kilowatt-hour (Btu/kWh). The performance of a power plant is measured by its fuel consumption rate (Btu/hr) and the corresponding amount of electric energy generated; thus, heat rate can be used to indicate the efficiency with which thermal energy is converted into electric energy.
Heating Degree-day	A measure of how cold a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the average of the day's high and low temperatures from the base temperature (65 degrees), with negative values set equal to zero. Each day's heating degree-days are summed to create a heating degree-day measure for a specified reference period. Heating degree-days are used in energy analysis as an indicator of space heating energy requirements or use.
Heating, Ventilating and Air Conditioning (HVAC)	Technology which provides indoor air comfort.
Hedging	The attempt to eliminate at least a portion of the risk associated with owning an asset or having an obligation by acquiring an asset or obligation with offsetting risks. For example, a company that has an obligation to purchase fuel oil in six months may want to eliminate the risk that prices will increase before that time. In this case, the company could hedge, or reduce, that risk by purchasing a futures contract that provides the right to purchase fuel oil at a fixed price. Any profit or loss on the futures contract should offset the effects of higher or lower oil prices at the time the company needs to buy oil.
Hg (Mercury)	***See*** Mercury
Hub	In the context of the electric grid, a hub is a location on the transmission network having a high concentration of interconnected transmission lines, generating sources, and/or counterparties willing to transact power trades such that this becomes a location having a great deal of commercial activity.
Hybrid Cooling	A type of technology that utilizes a combination of water cooling and dry cooling techniques. The relative contribution from each is dependent upon the plant design, weather conditions, and water consumption policies. ***See also*** Dry Cooling.
Integrated Gasification Combined Cycle (IGCC)	A power generation technology which allows a reduction of emissions by combining two technologies: (1) coal gasification, which uses coal to create a clean-burning gas; and, (2) combined cycle generation.
Intensity	Metric employed to characterize the emission of pollutants, relative to the power produced. For example, tons of CO_2 emitted per MWh or gallons of water used per MWh can be used to help characterize the energy intensity of the system resources independent of load growth.
Interconnection	A connection between two electric systems permitting the transfer of electric energy in either direction. Additionally, an interconnection refers to the facilities that connect a generator to a system.
Intermediate Resource	Generation resources that usually fulfill a somewhat flexible role in the generating system. During some times of the year, these generating units will be started in the morning hours, used to meet daytime peak loads and then brought off-line in the evening. The operation may change during heavier load times of the year when these units may operate in more of a baseload manner and remain on-line for all hours of the day.

GLOSSARY (CONTINUED)

Intermittent (or Variable [Energy]) Resource	Generating resources that have some degree of variability in the production pattern, typically due to weather conditions. An example of an intermittent generating source is a wind project. The power output from the wind project is entirely dependent upon the wind conditions and will fluctuate with changes in wind conditions.
Investment Tax Credit (ITC)	Allows taxpayers to take a dollar-for-dollar reduction in the amount of federal income taxes that must be paid. Certain qualified facilities are characterized as energy property and are eligible for tax credit, depending on the technology. A taxpayer cannot take both an ITC and PTC for a facility that could qualify for both; one must elect to receive either an ITC or PTC for each project.
Kilowatt (kW)	Unit of measure for demand. One thousand Watts.
Kilowatt-Hour (kWh)	Unit of measure for energy. The equivalent of one thousand Watts used steadily for one hour.
Landfill gas	Gas that is generated by decomposition of organic material at landfill disposal sites. The methane in landfill gas may be vented, flared, combusted to generate electricity, or used as thermal energy on-site.
Light-Emitting Diode (LED)	A semiconductor light source increasingly used for lighting. LEDs present many advantages over incandescent light sources including lower energy consumption, improved robustness, smaller size, faster switching, and greater durability and reliability.
Load	The moment-to-moment measurement of the power requirement in the entire system.
Load Center	A point at which the load of a given area is assumed to be concentrated.
Load Pocket	A geographic area that has a high demand of energy constrained by transmission import limitations. For example, the metro Phoenix area is considered a load pocket.
Loads & Resources Table	Presents the annual expected resource needs and additions.
Loss of Load Probability (LOLP)	The probability that generation resources will fall short of the resource need. The LOLP is expressed as a number between 0 and 1.
Losses on Peak	Total electric energy losses during the hour of greatest energy demand. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution equipment (wire, transformers, etc.).
Low NOx Burner (LNB)	A type of burner that is typically used in utility boilers to produce steam. Air used for combustion is split into two or more parts. The initial combustion, which occurs at a high temperature, takes place in an oxygen-deficient condition to form molecular nitrogen (N_2) instead of NOx. Further down the flame, additional air is added to complete the combustion after the nitrogen has been driven out of the coal as N_2.

GLOSSARY (CONTINUED)

Lowest Achievable Emission Rate (LAER)	The most stringent emission limitation derived from either of the following: (a) the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or, (b) the most stringent emission limitation achieved in practice by such class or category of source. The emissions rate may result from a combination of emissions-limiting measures such as: (1) a change in the raw material processed; (2) a process modification; and, (3) add-on controls.
Major Modification	Any physical change or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.
Major Sources	Term used to determine applicability of permitting regulation to stationary sources. For Title V of the Clean Air Act, refers to sources of air pollution that emit or have the potential to emit 100 tons per year or more of any criteria air pollutant.
Maximum Achievable Control Technology (MACT)	The standards which are established by EPA to require the maximum degree of emission reduction that EPA determines to be achievable for hazardous air pollutants. These standards are authorized by Section 112 of the Clean Air Act.
Megawatt (MW)	One megawatt equals one million watts. ***See*** *Watt*
Megawatt-Hour (MWh)	One million watt-hours ***See*** *Watt-Hour*
Mercury	A naturally-occurring element that is found in air, water and soil. Coal contains mercury and when coal is burned, mercury is released into the environment.
Must Take Generation	Electricity production that must be taken when it is produced by the utility. Generally refers to qualifying facilities under the Public Utility Regulatory Policies Act (PURPA).
Nameplate Rating (or Nameplate Capacity or Nameplate)	A rating for each resource that specifies the maximum expected output of the resource.
National Ambient Air Quality Standards (NAAQS)	The standards established by EPA under authority of the Clean Air Act that apply to outdoor air throughout the country. Primary standards are designed to protect human health, with an adequate margin of safety.
National Environmental Policy Act (NEPA)	Establishes a process by which federal agencies must study the environmental effects of their actions, so these effects can be taken into consideration during federal decision-making.
Net Present Value (NPV)	Method for evaluating the cost or profitability of an investment. Individual future cash amounts are discounted back to their present values and then summed.
New Source Performance Standards (NSPS)	Pollution control standards issued by the Environmental Protection Agency.

GLOSSARY (CONTINUED)

New Source Review (NSR)	A permitting program that was established by Congress as part of the 1977 Clean Air Act Amendments. NSR is a preconstruction permitting program to ensure air quality is not significantly degraded from the addition of new and modified factories, boilers, and power plants and that advances in pollution control occur with industrial expansion.
Nitrogen Oxide (NOx)	Compounds of nitrogen and oxygen formed by combustion under high temperature and high pressure and a major contributor to the formation of ozone.
Non-Spinning Reserves	A generating reserve not connected to the system but capable of serving demand within a specified time, usually ten minutes.
North American Electric Reliability Corporation (NERC)	NERC is a non-government organization which has statutory responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices.
Nuclear Fuel	Fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.
Nuclear Regulatory Commission (NRC)	The federal agency responsible for the regulation and inspection of nuclear power plants to assure safety.
Off-Peak	Period of relatively low system demand. These periods often occur in daily, weekly, and seasonal patterns.
On-Peak	Periods of relatively high system demand. These periods often occur in daily, weekly, and seasonal patterns.
Operating Reserves (or reserves or Contingency Reserves)	A combination of spinning and non-spinning reserves. Operating reserve is the portion of all reserves APS is required to carry over and above firm system demand to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. APS carries a 15% reserve margin.
Operation & Maintenance (O&M)	Actions taken after construction to ensure that facilities constructed will maintain performance by being properly operated and maintained to achieve normative efficiency levels in an optimum manner.
Ozone	Ozone, the triatomic form of oxygen (O_3), is a gaseous atmospheric constituent. In the troposphere, it is created both naturally and by photochemical reactions involving gases resulting from human activities (photochemical smog). The layer of ozone that begins approximately 15 km above Earth and thins to an almost negligible amount at about 50 km, shields the Earth from harmful ultraviolet radiation from the sun.
Palo Verde Hub	An energy hub (***see*** *Hub*) in the area of PVNGS located west of Phoenix, Arizona, where numerous regional counterparties engage in power transactions which form the basis for various indices. For example, the Dow Jones Palo Verde Electricity Price Indexes are volume-weighted averages of specifically-defined bilateral, wholesale, and physical transactions in the hub quoted in either $/MWh or $/MW.
Particulate Matter	Particle pollution in the air that includes a mixture of solid particles and liquid droplets.

GLOSSARY (CONTINUED)

Peak Demand (or Peak Load or Peak)	The greatest demand that occurred or is expected to occur during a prescribed time period.
Peaking Resources	Technologies used to respond to high customer demands during the hot summer afternoons. These could include combustion turbines and DR measures and may include short-term market purchases.
Peaking Units	These generation units usually see relatively infrequent service during the non-summer months. During the summer, peaking units are used during the hot summer afternoons in response to high customer demands. It is not unusual for peaking units to operate less than 10% of the hours during the year.
PM10	Particles with diameters that are 10 micrometers or smaller. Sources of particles include combustion, crushing or grinding operations, and dust from paved or unpaved roads.
Power Tower	Flat, sun-tracking mirrors, known as heliostats, focus sunlight onto a receiver located at the top of a tall tower. A heat-transfer fluid is used to heat a working fluid, which, in turn, produces electricity in a conventional turbine generator. Working fluids have high heat capacity, which can be used to store the energy (to generate power after the sun sets) before using it to boil water to drive turbines.
Preference Power	Federal hydropower and resources from the Colorado River system.
Prevention of Significant Deterioration (PSD)	EPA program in which state and/or federal permits are required in order to restrict emissions from new or modified sources in places where air quality already meets or exceeds primary and secondary ambient air quality standards.
Production Tax Credit (PTC)	Allows a tax credit for the amount of energy produced for electricity generated at qualified facilities. The PTC amounts, credit periods, and definitions of qualified facilities are technology-specific. A taxpayer cannot take both an ITC and a PTC for a facility that could qualify for both – one must elect to receive either an ITC or PTC for each project.
Public Utility Regulatory Policies Act (PURPA)	In response to the 1973 energy crisis, PURPA was enacted to promote 1) energy conservation (reduce demand), 2) greater use of domestic energy, and 3) renewable energy (increase supply).
Purchased Power Agreement (PPA)	A contractual agreement between two entities for the sale of electric energy and capacity from a specific generating unit, utility system, or unspecified wholesale market sources.
Real-Time Operations	Operational activity which manages the economic commitment of APS's generation resources to match the system load on a real-time basis. Requires making decisions to optimize system operation to provide lowest cost, reliable power to APS customers.
Real-Time Traders	Individuals involved solely in commodity trading of power, specifically electricity.
Regional Haze Rule	Requirements established by EPA to address source-by-source visibility impairment.
Regression Models	A statistical technique used to find relationships between variables for the purpose of predicting future values.
Renewable Energy	An energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.

GLOSSARY (CONTINUED)

Renewable Energy Standard (RES)	Requirement codified at A.A.C. R14-2-1804 which requires regulated electric utilities within Arizona to generate 15 percent of their energy from renewable resources by 2025.
Renewable Energy Standard Implementation Plan	Requirement for Arizona's regulated utility companies to file annual implementation plans describing how they will comply with the Renewable Energy Standard rules.
Request for Proposal (RFP)	A competitive solicitation for suppliers, often through a bidding process, to submit a proposal on a specific commodity or service.
Residential Direct Load Control	Demand response programs where the utility or a third-party contractor can remotely control customer-specific loads and reduce or cycle the energy consumption for a specified period of time.
Resource Conservation and Recovery Act (RCRA)	Gives EPA the authority to control hazardous waste from the "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also set forth a framework for the management of non-hazardous solid wastes.
Resource Planning Rules	Codified at A.A.C. R14-2-703, the Resource Planning Rules require regulated electric utilities to file a plan for future generation needs.
Revenue Requirements	Annual revenue level required to supply customers energy needs, including: (1) carrying charges on existing and future generation, future transmission over and above APS Ten Year Transmission Plan, and capital expenditures on existing generation; (2) fuel costs; (3) purchase power costs; (4) operating and maintenance costs for existing and future generation; (5) energy efficiency program and incentive costs; (6) distributed energy program and incentive costs; and, (7) power plant emissions costs including CO_2. Revenue requirements as used in the IRP do not include costs associated with existing transmission, existing and future distribution, or sales tax on retail electric sales.
Scenario Analysis	Refers to the grouping together of a set of assumptions of key uncertain variables that could potentially all occur in tandem. The goal of scenario analysis is to illustrate the impact to the portfolios of multiple key variables being stressed in a plausible manner. Results of these studies provide information on diversity, cost, environmental impacts, robustness and overall risk to assist in the selection of a resource plan.
Selective Catalytic Reduction (SCR) Controls	A post-combustion pollution control technology that removes NOx emissions from an air stream. Ammonia (NH_3) is injected into the flue gas downstream from the combustion process and upstream from a catalyst bed. The NH_3 reacts with the NOx on the catalyst surface to form nitrogen (N_2) and water vapor (H_2O).
(Retail) Service Territory	The area where a utility provides power.
Simple Cycle	***See*** *Combustion Turbine*
Societal Cost Test (SCT)	A variant of the Total Resource Cost Test. It measures the impacts of DSM on society as a whole by including externality costs of power generation not captured by the market.
Solar Photovoltaic (PV, or Solar PV)	A method of generating electrical power by converting solar radiation directly into electricity.

GLOSSARY (CONTINUED)

Solar Thermal	A method for harnessing solar energy for thermal energy.
Southern California Edison (SCE)	One of the largest electric utilities in California, serving more than 14 million people in a 50,000 square-mile area of central, coastal and Southern California, excluding the City of Los Angeles and certain other cities.
Southwest Reserve Sharing Group (SRSG)	A NERC-registered entity. SRSG participants share contingency reserves to maximize generator dispatch efficiency and contribute to electric reliability in the Western Interconnection.
Spinning Reserves	Available generating capacity that is synchronously connected to the electric grid and capable of automatically responding to frequency deviations on the system.
Spot Market	A commodities or securities market in which goods are sold for cash and delivered immediately.
Standby Generation	Customer-owned generation resources, typically diesel- or gas-fired, that provide customers with a guaranteed source of power in the event that either power quality or reliability issues occur with their local utility.
Startup Costs	The costs associated with starting a power plant. These costs have become more of a consideration as more variable energy resources have been added to the electricity system and start-ups have become more frequent for some types of generation.
State Implementation Plan (SIP)	Plans developed by state and local air quality management agencies and submitted for approval to EPA to comply with the federal Clean Air Act.
Strategist	An ABB company resource expansion plan optimizing software model.
Sulfur Dioxide (SO2)	A colorless gas of compounds of sulfur and oxygen that is produced primarily by the combustion of fossil fuel.
Summer Peak	***See*** *Peak Demand*
System Average Interruption Duration Index (SAIDI)	Used as a reliability indicator by electric power utilities. SAIDI is the average annual outage duration experienced by the average customer.
System Average Interruption Frequency Index (SAIFI)	Used as a reliability indicator by electric power utilities. SAIFI is the average annual outage frequency experienced by the average customer.
Thermal Energy Storage (TES) Cooling Programs	Systems that utilize a storage medium, such as chilled water or ice, which is “charged” during off-peak hours and then used as the cooling energy source during on-peak hours, offsetting the need to operate high-demand refrigeration equipment.
Total Own Load Peak	The greatest demand for energy during a specified time period by customers that APS has a requirement to serve.
Total Resource Cost Test (TRCT)	Measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's.

Transmission	The transportation of bulk energy along a network or grid of power lines. It is often intended to refer specifically to high-voltage (69,000 volts or higher) electricity of the type bought and sold on the wholesale market. An additional stage of service, referred to as distribution, is required to actually deliver usable low-voltage energy to an end-use customer.
Utility-Scale	A resource that is sized to provide power to a utility and not directly to an on-site customer.
Volatile Organic Compounds (VOC)	Types of organic compounds which have significant vapor pressures (evaporate easily, forming a gas) and which can affect the environment and human health.
Water Intensity	The amount of water needed to produce a unit of electricity. In general, this document will give water intensity as acre-feet per megawatt-hour.
Watt-Hour	The total amount of energy used in one hour by a device that requires one watt of power for continuous operation. Electric energy sold to retail customers is commonly measured in kilowatt-hours.
Watt	The electrical unit of real power or rate of doing work; specifically, the rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor.
WestConnect	WestConnect is composed of utility companies providing electric transmission in the U.S. Members work collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to Western wholesale electricity markets.
Western Electricity Coordinating Council (WECC)	The regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.
Western Interconnection	The interconnected electrical systems that encompass the region of the Western Electricity Coordinating Council of the North American Electric Reliability Council. The region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California (Mexico), and all or portions of the 14 western states in between, including Arizona.
Western Interstate Energy Board (WIEB)	Organization of 11 western states and three western Canadian provinces. Board Members are appointed by state governors. The Board provides the instruments and framework for cooperative state efforts to "enhance the economy of the West and contribute to the well-being of the region's people."
Wholesale Customer	Any party who purchases electricity in bulk for resale to end-use customers. Wholesale customers may include marketers, utilities and distribution companies, co-ops, and any other entity engaged in energy resale.
Zero Liquid Discharge (ZLD)	A treatment process designed to remove all the liquid waste from a system. The focus of ZLD is to reduce wastewater economically and produce clean water that is suitable for reuse (e.g. irrigation), thereby saving money and being beneficial to the environment. ZLD systems employ advanced wastewater treatment technologies to purify and recycle virtually all of the wastewater produced.

APPENDIX A

GUIDEHOUSE DSM OPPORTUNITY STUDY

APS DSM OPPORTUNITY STUDY

RESULTS AND FINDINGS

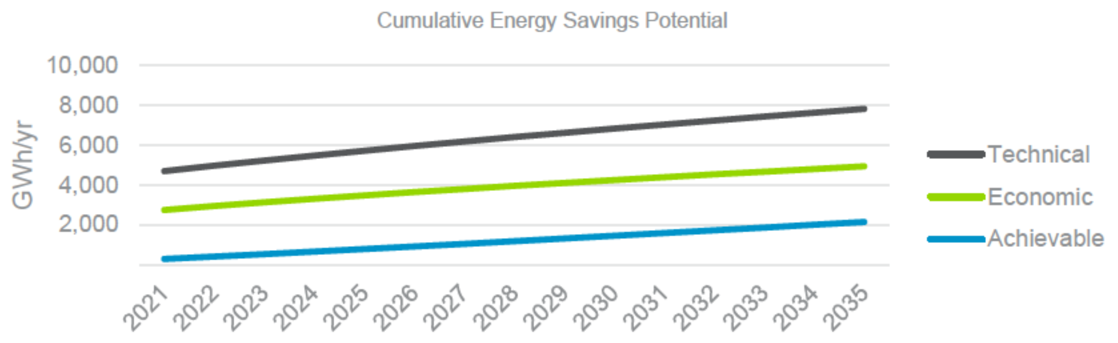
MAY 20, 2020

EXECUTIVE SUMMARY

APS forecasted energy savings & costs for EE opportunities between 2021-2035 to support IRP and DSM planning efforts.

- **Scope**: 34 new and existing EE technologies across 8 customer segments, and 2 climate zones.
- **Methodology:** Combined APS DSM planning, load forecasting, and resource planning data with market saturation information from 60 subject matter experts to develop estimates of Technical, Economic, and Achievable potential and corresponding costs.

Approximately 60% of technical potential savings pass the economic screen of the ACC Societal Cost Test.



APS can achieve between 175 GWh and 200 GWh in cost effective energy savings at a cost of $37M to $49M annually.

- **Residential Sector** EE potential primarily consists of:
  - Specialty LEDs, HVAC Quality Installation, and Energy Star Homes.
- **Non-Residential Sector** EE potential primarily consists of:
  - Data Center Computer Room AC, Custom Projects, and Strategic Energy Management programs
- Other technologies contributing to achievable EE potential include:
  - Smart Thermostats, Linear LEDs, Packaged AC, Home Energy Reports, Limited Income Weatherization, Attic Insulation, and Multifamily New Construction

APS incorporated these opportunities into its 2020 DSM Plan. In addition to the EE potential identified here, APS is currently conducting a second market potential study focused on the following Distributed Flexible Capacity opportunities :

Demand Response

Energy Storage

Managed EV Charging

Strategic Beneficial Electrification

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STUDY OBJECTIVES AND METHODOLOGY

Forecast energy and demand reductions and costs for demand-side management opportunities that provide the most value to APS and its customers between 2021-2035.

Data Collection
- 60+ Market Actor Interviews

Model Input Development
- Measure Savings, Costs, Densities, Saturations
- APS Avoided Cost Data, Building Stock and Sales Forecasts

Technical Potential
- DSM potential for all technically feasible measures, regardless of economics or customer acceptance

Economic Potential
- DSM potential for measures that pas the ACC SCT, regardless of customer acceptance

Achievable Potential
- DSM potential based on customer acceptance

Establish Goals and Insights for IRP and DSM Planning

CONSIDERATIONS

Please keep in mind the following caveats related to the scope of the study.

- The team used data available at the time of the study. The data presented represents a snapshot informed by that data and should be considered informational and directional to support IRP and DSM planning efforts.
- The study includes measures that provide the bulk of energy savings for APS's current DSM portfolio, as well as emerging technologies that help customers manage their energy bills.
- The study does not include all measures in the current APS portfolio or emerging initiatives such as Demand Response, Electrification, Energy Storage, and Managed EV Charging.
- Cost-effectiveness is based on the current version of the Arizona Corporation Commission Societal Cost Test (ACC SCT).

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MEASURE LIST

The measure list covers current APS offerings as well emerging technologies – specifically controls – that enable customers to manage TOU and Demand-based rates. Savings, costs, and load shapes for the desert and mountain regions developed through MER research served as inputs to the model.

RESIDENTIAL
(Single Family and Multi-Family)

Measure Category	Measure Name
New Construction	Energy Star Homes
	Multi-family New Construction
	Smart Homes (New Construction)
Behavioral	Behavioral (e.g., Home Energy Reports/Digital Assistant)
HVAC	HVAC Quality Installation (QI) of baseline SEER 14 HVAC
	HVAC Quality Installation (QI) of SEER 15 HVAC
	HVAC Quality Installation (QI) of SEER 16.2 HVAC
	Duct Test & Repair
	Western Cool Controls
	Smart Thermostat
Weatherization	Attic Insulation
	Limited Income Weatherization
Appliances	Advanced Connected Pool Controls
Water Heating	Connected ER Water Heater
	Connected HPWH
Lighting	LED Specialty Lighting Upgrade

NON – RESIDENTIAL
(Office, Lodging, Schools, Retail, Data Centers, Other)

Measure Category	Measure Name
New Construction	Commercial New Construction
Custom	Custom Retrofits
Behavioral	Behavioral and Strategic Energy Management
HVAC	Air- and Water-Cooled Chillers
	Packaged AC/HPs
	Energy Management Systems (EMS)
	Advanced Rooftop HVAC Controls
	Non-Res Duct Test & Repair
Lighting	Lighting Power Density (C&I New Construction)
	Networked Connected Lighting Controls Retrofit
	Linear LEDs
	Exterior Lighting LPD
Refrigeration	High Efficiency Evaporator Fan Motors (EC)
	Floating Head Pressure Controls
	Anti-Sweat Heater Controls
Data Centers	Data Center Computer Room AC (CRAC) Upgrades
	Data Center Uninterruptible Power Supply (UPS)
	Server Virtualization

DATA COLLECTION

We interviewed 60 subject matter experts across customer segments and technologies to develop market saturation inputs and provide useful program design insights.

Last Name	First Name	Organization	Title
Avades	Jalal	AGR Consulting	Principal
Baggett	Chris	APS	Program Manager
Baker	Chris	APS	Program Manager
Benson	Corey	EnergyHub	Manager, BD and Partnerships
Bevacqua	Forrest	Foundations for Senior Living	HVAC QA/QC Manager, Arizona Home
Bishop	Richard	Paradise Valley Unified School District	Energy Systems Manager
Bondra	Jason	WESCO	Lead Program Manager
Brandt	Don	Self	Engineer
Brudenell	Linnea	Nelsen Partners	Director of Sustainability
Burki	Taimur	Intel Corporation	Sustainability Program Manager
Chaverria	Jose	ASU	Energy Efficiency Manager
Chestnutwood	Donald	CBRE	Chief Engineer
Chrimat	Elena	Ideal Energy LLC	Principal
Collera	Rodyn	Energy Systems Design	Mechanical Designer
Coy	Robert	Midstate Energy, LLC	Director, Lighting
Dobberpuhl	Wayne	Nexus Energy Solutions	Principal
Duede	Gary	DNV GL	Senior Engineer
Eisen	Eileen	APS	Marketing Manager, Consumer Programs
Farlow	Jeff	Pentair	Program Manager, Energy Initiatives
Floyd	Anthony	City of Scottsdale	Senior Energy/Green Building Consultant
Garcia	Rogelio	Sigler Carrier	Sales Engineer
Gibbons	Jeff	Bridge House Advisors	Environmental Business Advisor
Gibson	Christi	Noresco	Proposal Manager
Gidley	Julie	CLEAResult	Senior Manager
Gohman	Charlie	Foundations for Senior Living	Manager, Home Performance w/ ENERGY STAR
Gorombei	James	City of Phoenix	Energy Management Specialist
Heitzinger	Jon	Northern Arizona University	Associate Director of Utilities
Hessler	DeeDee	APS	Program Manager
Humbert	Raymond	Arizona State University	Associate Director, Parking and Transportation
Hunter	Daniiel	Ameresco	Senior Account Executive

Last Name	First Name	Organization	Title
Johnston	Tom	Johnston Engineering	Principal
Jordan	Dave	Rheem	IoT Partnership Manager
Justin	Karl	ECS Arizona	Principal
Kosmicki	Jeff	Coconino County	Supervisor, Facility Management
Krecic	Lara	DNV GL	Section Head, Program Development & Impl
Laisure-Pool	Colin	Mechanical Products SW	Sales Engineer
Lander	Eric	Trane Residential HVAC and Supply	General Manager, Southwest District
Landon	Halleh	Energy Systems Design	Principal
Maheshwari	Ankur	Rheem	Senior Product Manager
Martz	Bruce	Trane	Sales Manager
Mulhall	Ashley	Orcutt|Winslow Partnership	Senior Associate
Mundell	Jeffrey	Trane	Project Developer
Mundt	Noah	Nexus Energy Solutions	Principal
Munn	Dave	David Munn Consulting PLLC	Principal
O'Connor	Alex	Healthcare Trust of America	Director of Facilities
Porter	Daniel	Paragon Services	VP, Operations
Pretzman	Richard	Arizona State Univerisity	Associate Director, Energy & Utilities
Rogers	Tyler	EnergyHub	Director of Utility Sales
Rose	Micah	Evergreen Consultants	Lighting Specialist
Sexton	Randy	Scottsdale Marriott Suites	Director of Engineering
Shami	Usama	APS	Key Accounts Manager
Sheridan	Heidi	Electric League of Arizona	Executive Director
Stanton	Jeff	SmithGroup	VP, Architect, Sustainability Leader
Swanson	Trevor	APS	Program Manager, Solutions for Business
Tan	Ben	Fry's Food and Drug	Energy Manager
van Lambalgen	Henny	Quest Energy Group	Principal
Wallace	Brian	APS	Key Account Manager
Walsh	Ed	DNV GL	Senior Energy Engineer
Williams	Alex	Ideal Energy LLC	Principal
Young	Neil	Schneider Electric	Client Manager

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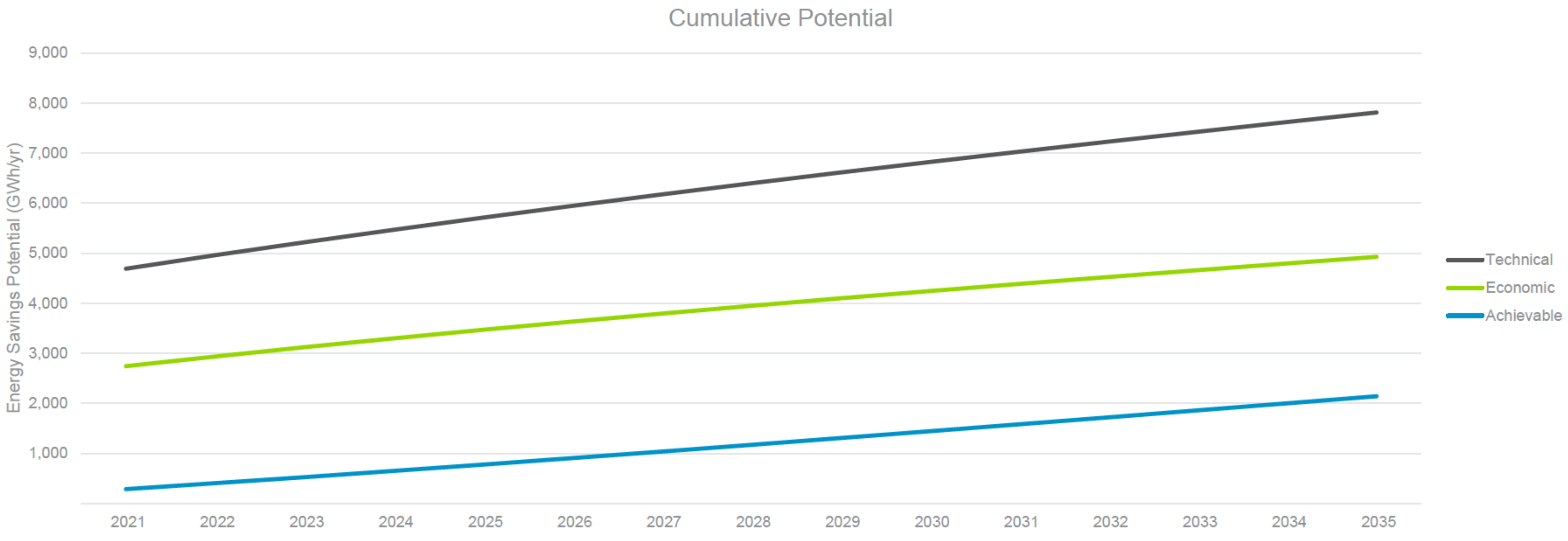
COMPARISONS OF POTENTIAL

Approximately 60% of technical potential savings pass the current version of the ACC Societal Cost Test (i.e. Economic) and the market will adopt 27% of the technical potential savings by 2035 (i.e. Achievable).



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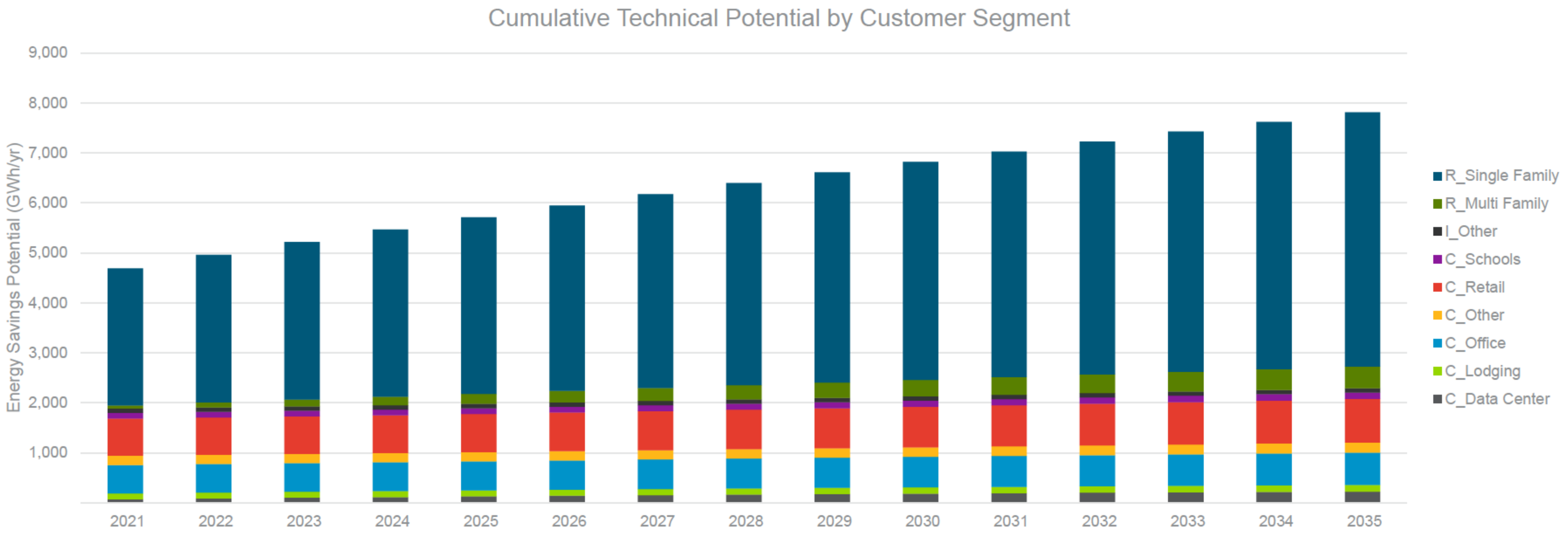
TECHNICAL POTENTIAL

Growth in the residential market results in a doubling of technical potential by 2035 while potential remains the same in the commercial sector.



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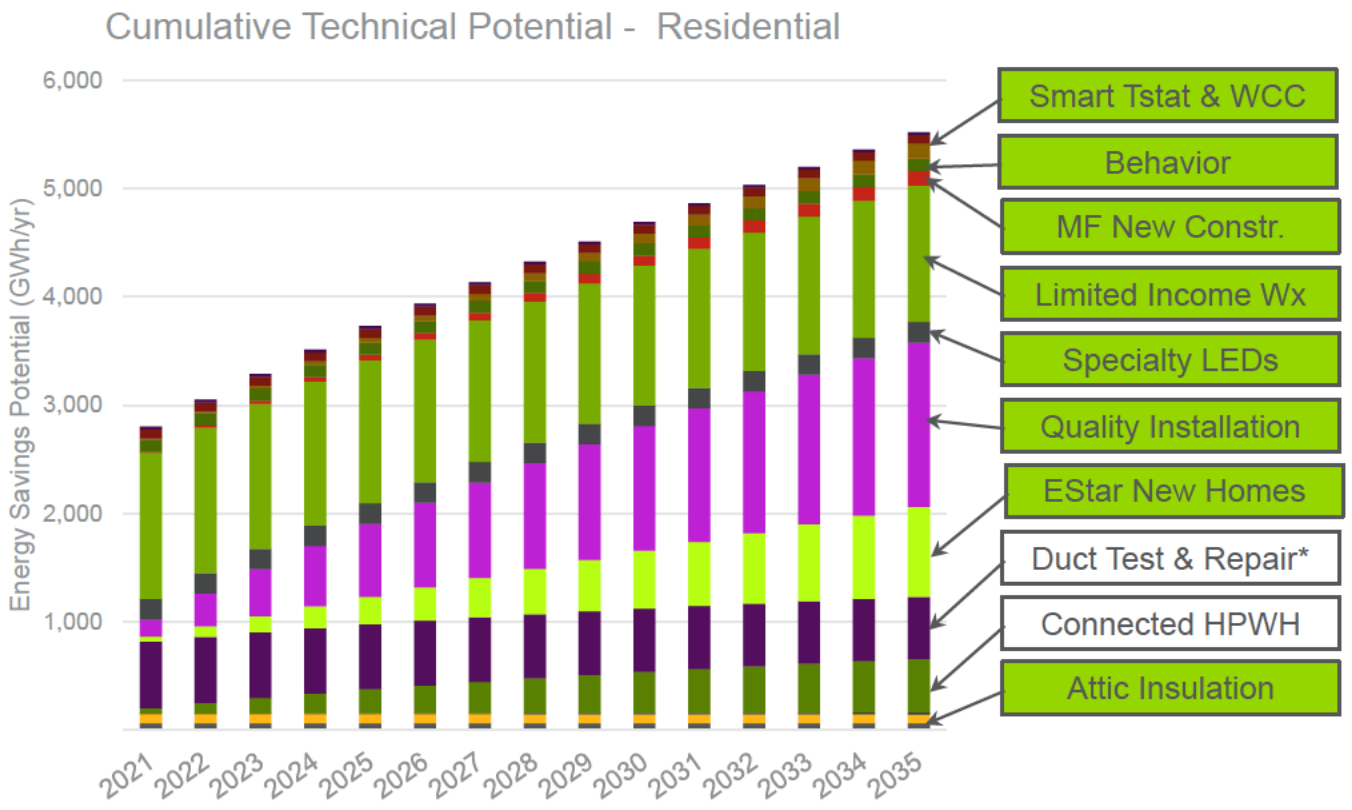
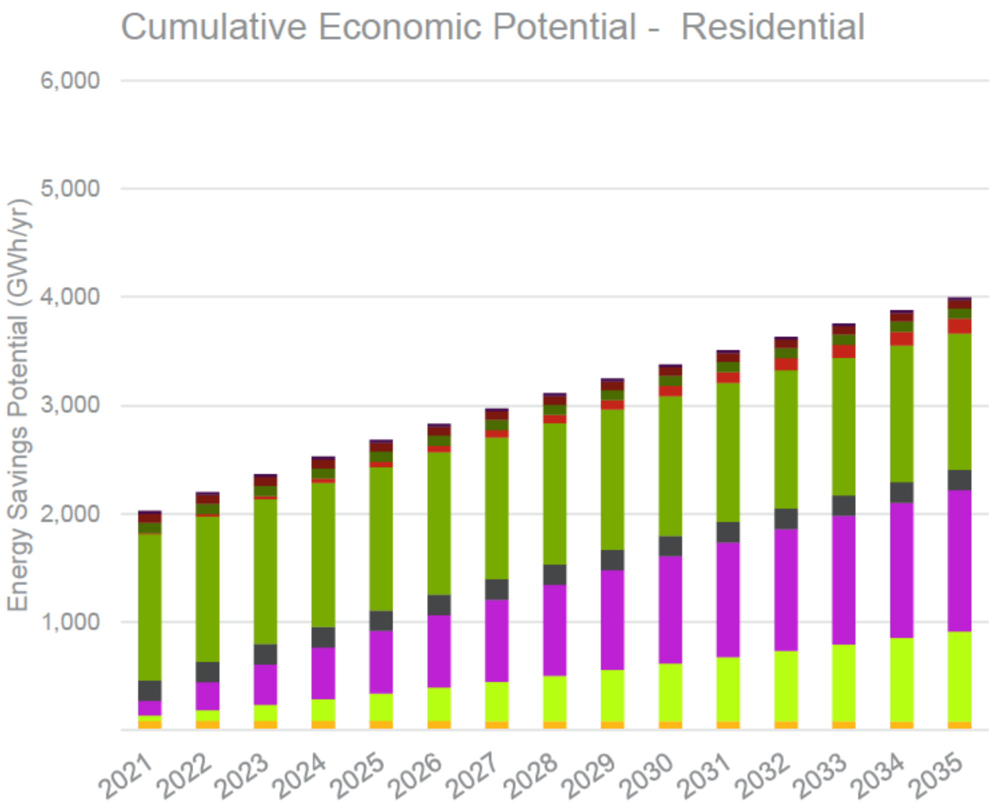
ECONOMIC POTENTIAL - RESIDENTIAL

Economic potential represents the technical potential that passes the current version of the ACC Societal Cost Test. Cost-effective measures are highlighted in green.

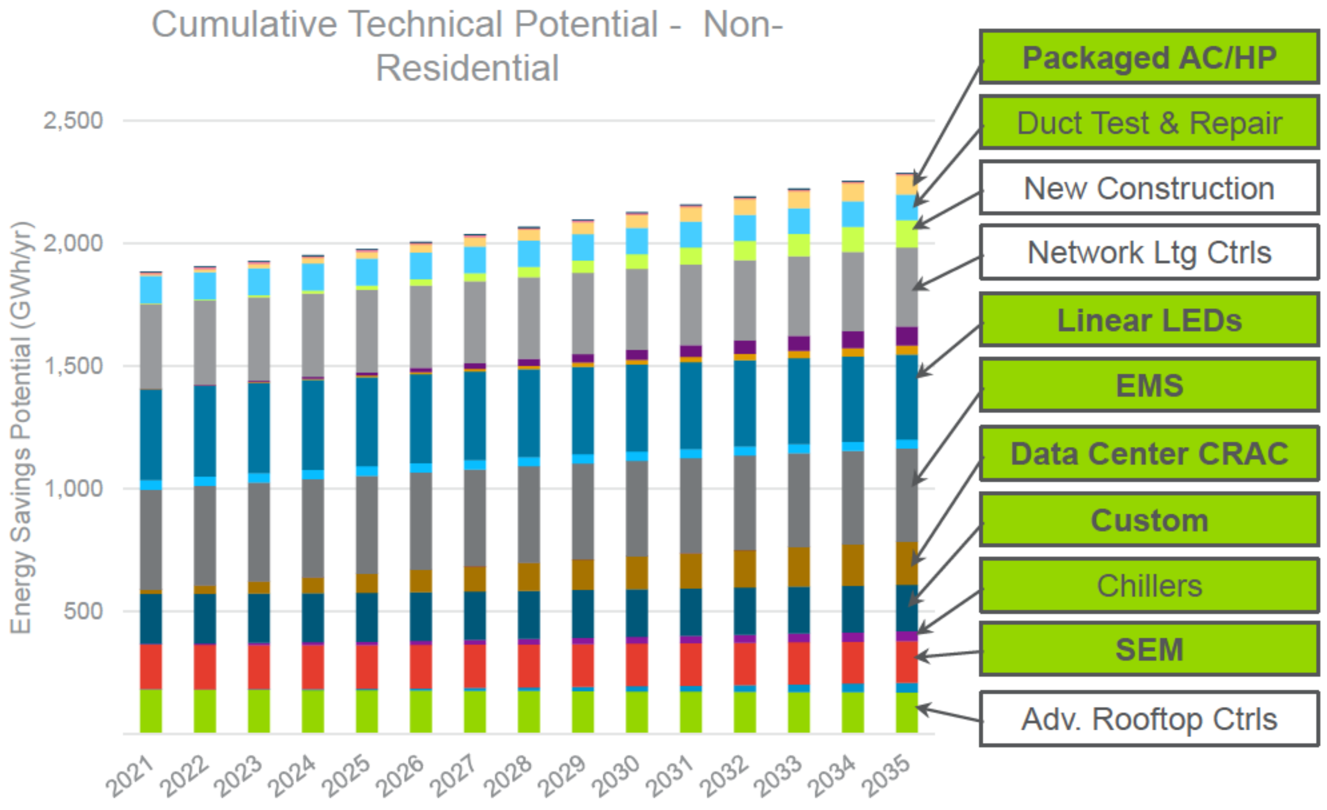


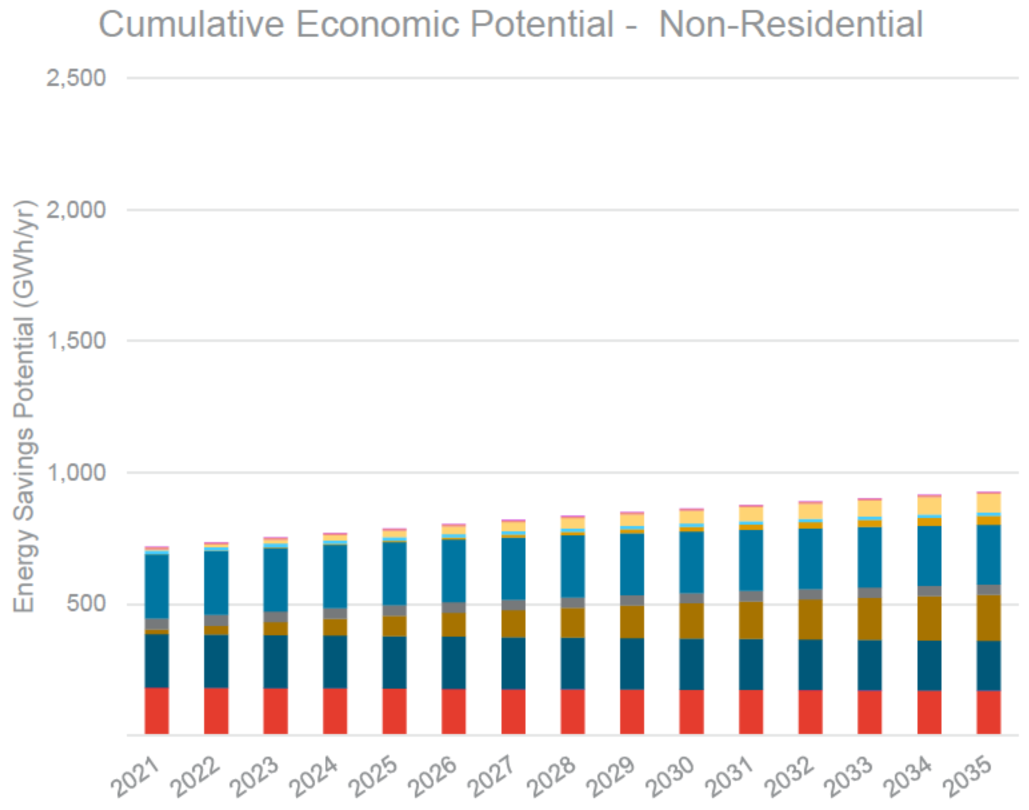


*Duct Test & Repair is borderline cost-effective and is under review.

ECONOMIC POTENTIAL- NON-RESIDENTIAL

Changes between technical and economic potential in C&I are driven by differences in hours of operation and HVAC loads across customer segments (Lodging, Schools, Office, Retail, Other).





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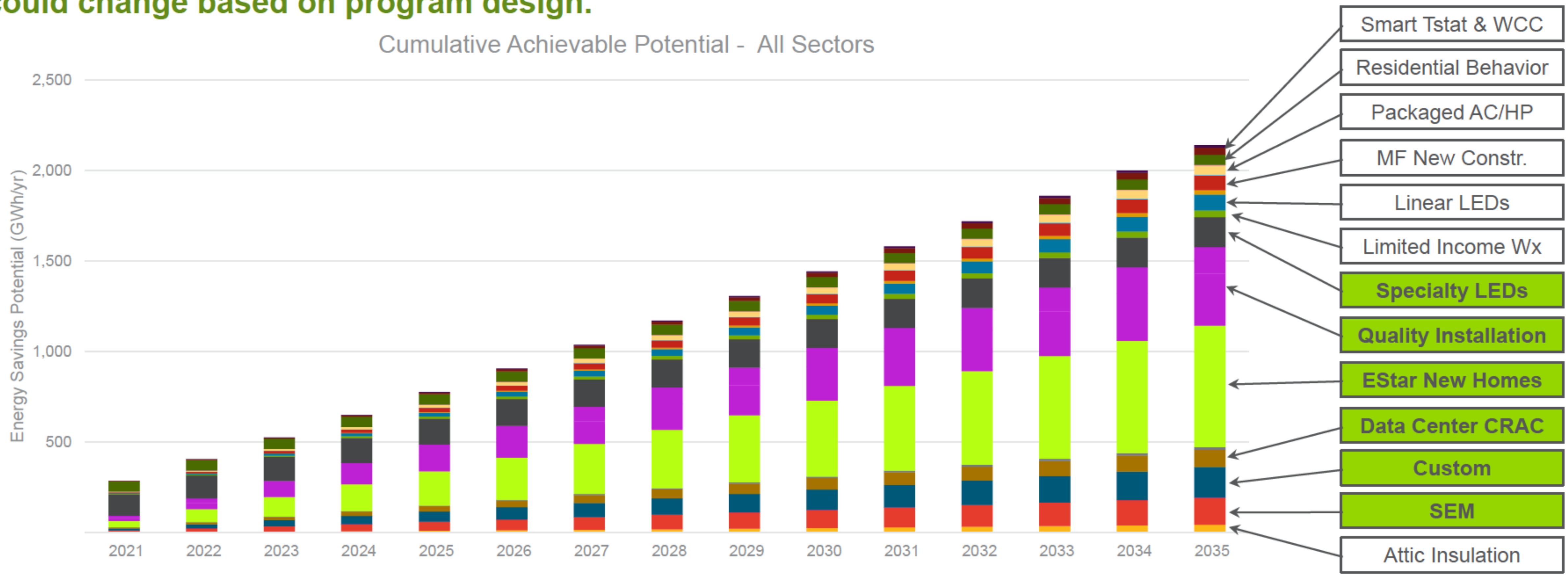
ACHIEVABLE POTENTIAL - CUMULATIVE

Achievable potential accounts for the portion of customers that will purchase the efficient technology, calibrated to past program participation. Annual potential ranges from 175 GWh and 200 GWh per year and could change based on program design.



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SUMMARY

The following are key takeaways related to the measures included in the DSM opportunity study.

- Approximately 60% of technical potential savings pass the current version of the ACC Societal Cost Test (i.e. Economic) and the market will adopt 27% of the technical potential savings by 2035 (i.e. Achievable).

- Some technologies pass the ACC SCT in certain customer segments, but not all, due to differences in building operation – such as lighting hours of use, and cooling loads.
  - This is most notable in the Non-Residential sector and differs from the way programs are currently implemented.

- APS can achieve between 175 GWh and 200 GWh in energy savings at a cost of $37M to $49M annually, from the group of measures evaluated in this study.
  - Specialty LEDs, Quality Installation, and Energy Star Homes in the residential sector, and Data Center CRAC, Custom and Strategic Energy Management in the non-residential sector comprise the majority of achievable potential.

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[1] On October 11, 2019, Guidehouse LLP completed its previously announced acquisition of Navigant Consulting Inc. In the months ahead, we will be working to integrate the Guidehouse and Navigant businesses. In furtherance of that effort, we recently renamed Navigant Consulting Inc. as Guidehouse Inc.

APPENDIX B

GUIDEHOUSE ELECTRIC VEHICLE ADOPTION STUDY

ELECTRIC VEHICLE ADOPTION FORECAST AND CHARGING STATION SITING ANALYSIS

ARIZONA PUBLIC SERVICE

DECEMBER 12, 2019

IRP STAKEHOLDER MEETING

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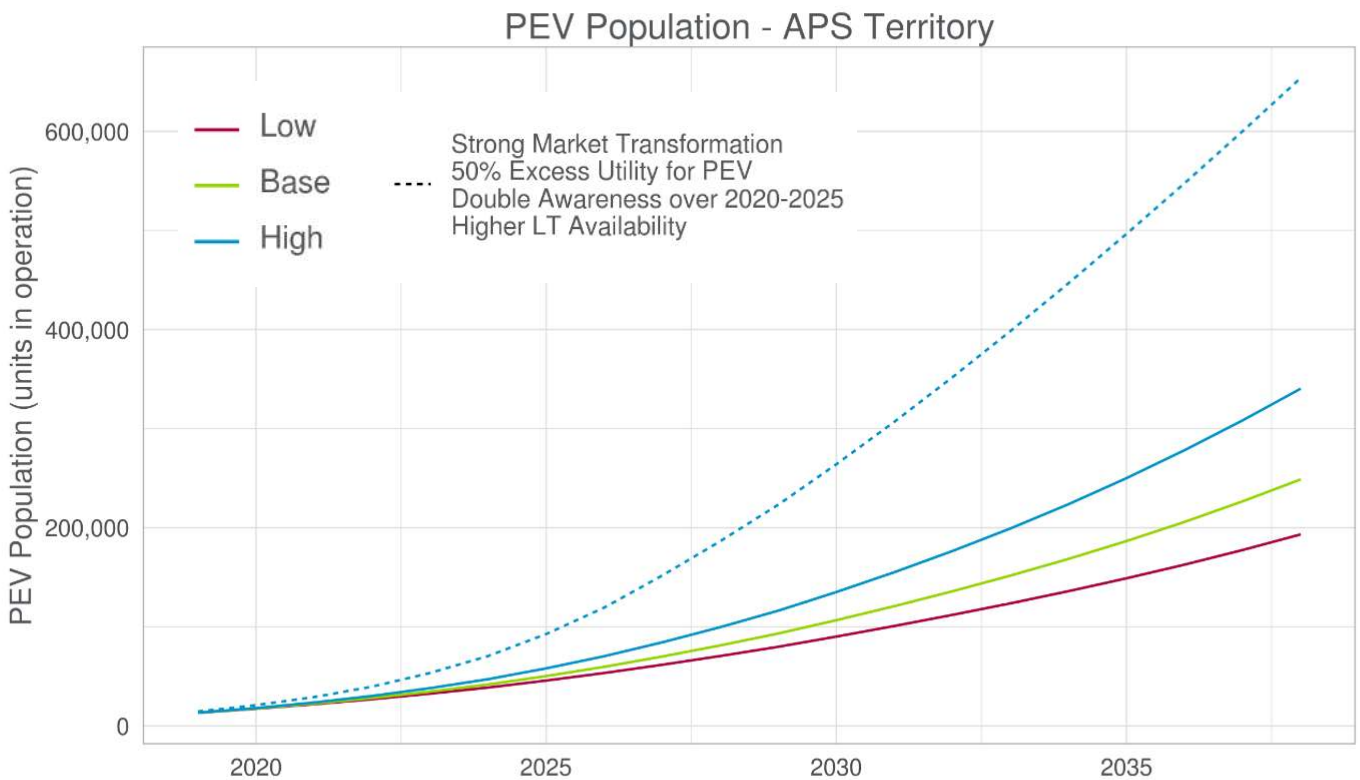
EV ADOPTION FORECASTED IN ARIZONA



Source: Navigant

Navigant estimates the number of light duty* ***plug-in electric vehicles (PEVs)*** in APS's territory will increase from about 10,000 in 2018 to about ***250,000 in 2038*** if the current market trajectory persists, under the ***Base scenario***.

Under the ***Market Transformation scenario***, the number of PEVs could reach ***650,000 by 2038*** in APS's territory and 1.5 million statewide if there are significant changes in consumer preference, awareness, and PEV product availability in the near-term.

* The contents of this report pertain only to light duty vehicles.

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MODELING OVERVIEW

NAVIGANT'S VEHICLE ADOPTION SIMULATION TOOL™ (VAST)

PURPOSE

The **VAST™ Adoption** module is a systems dynamics model that forecasts the penetration of vehicles, by powertrain (battery electric vehicle [BEV], plug-in hybrid electric vehicle [PHEV]), vehicle class, and ownership type (individual/fleet) for plug-in electric vehicles (PEV). It was used to generate geographic outputs for estimated vehicles in operation at the state, territory, and census tract level.

The **VAST™ Charging Forecasting** module estimates the number of chargers needed to meet future demand. The result can be used to estimate load growth, grid impacts, revenue generation, and more.

KEY INPUTS

- Baseline vehicle **registrations** and charging **infrastructure** – *from APS*
- Historic vehicle **sales** and vehicle **availability**
- Gasoline, battery, and component price forecasts – *including **electricity rates** from APS*
- State, national, and utility **incentives**
- **Demographic** data: Income, educational attainment, units in structure

KEY OUTPUTS

- Light-duty vehicle **registrations** and **sales** by year, powertrain, ownership, and census tract from 2019-2038
- Infrastructure, education/awareness, incentive, eligibility, and utility rate **sensitivity scenarios** to simulate market and utility interventions
- Number of **charging ports** by charger type in APS territory by census tract

EV Adoption

How many vehicles are on the road by type and location?

EVSE Forecasting

What charging infrastructure is required to support these vehicles?

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ADOPTION FORECAST SCENARIO DRIVERS

<table>
<tr><th></th><th></th><th colspan="2">High and Low Scenarios</th><th>Strong Market Transformation</th></tr>
<tr><th>Drivers</th><th>Description</th><th>Low</th><th>High</th><th>High</th></tr>
<tr><td>Incentive</td><td>Dollar per PEV tax incentive</td><td>No change</td><td colspan="2">Description: Additional “cash on the hood” incentive
Magnitude: $2,000 per vehicle
Timing: Throughout forecast</td></tr>
<tr><td>Battery Costs</td><td>Battery pack costs (dollars per kwh)</td><td>Description: Battery costs decrease less quickly, leading to increased operation cost of PEVs
Magnitude: Based on Navigant Research high battery cost forecast
Timing: Throughout forecast</td><td colspan="2">Description: Battery costs decrease more quickly, leading to decreased operation cost of PEVs
Magnitude: Based on Navigant Research low battery cost forecast
Timing: Throughout forecast</td></tr>
<tr><td>Gas Prices</td><td>Gasoline prices (cents per gallon)</td><td>Description: Gasoline prices decrease, leading to decreased operation cost of ICEVs
Magnitude: 25% decrease
Timing: Throughout forecast</td><td colspan="2">Description: Gasoline prices increase, leading to increased operation cost of ICEVs
Magnitude: 25% increase
Timing: Throughout forecast</td></tr>
<tr><td>Marketing and Awareness</td><td>Influences customer familiarity (i.e., public awareness) and a prerequisite for adoption</td><td>Description: Consumer awareness below projected levels
Magnitude: Roughly one-third decrease
Timing: Throughout forecast</td><td>Description: Consumer awareness increases above projected levels due to marketing or other public awareness change
Magnitude: Roughly one-third increase
Timing: Throughout forecast</td><td>Description: Major marketing campaigns and strong consumer preference shift toward PEVs
Magnitude: Greater than threefold increase over projected levels
Timing: Exponential growth beginning in 2022 through 2027</td></tr>
<tr><td>Model Availability</td><td>OEM PEV models released into the Arizona market</td><td>No change</td><td>No change</td><td>Description: Increased Light Truck model availability
Magnitude: 25% increase
Timing: LT models introduced as early as 2019</td></tr>
</table>

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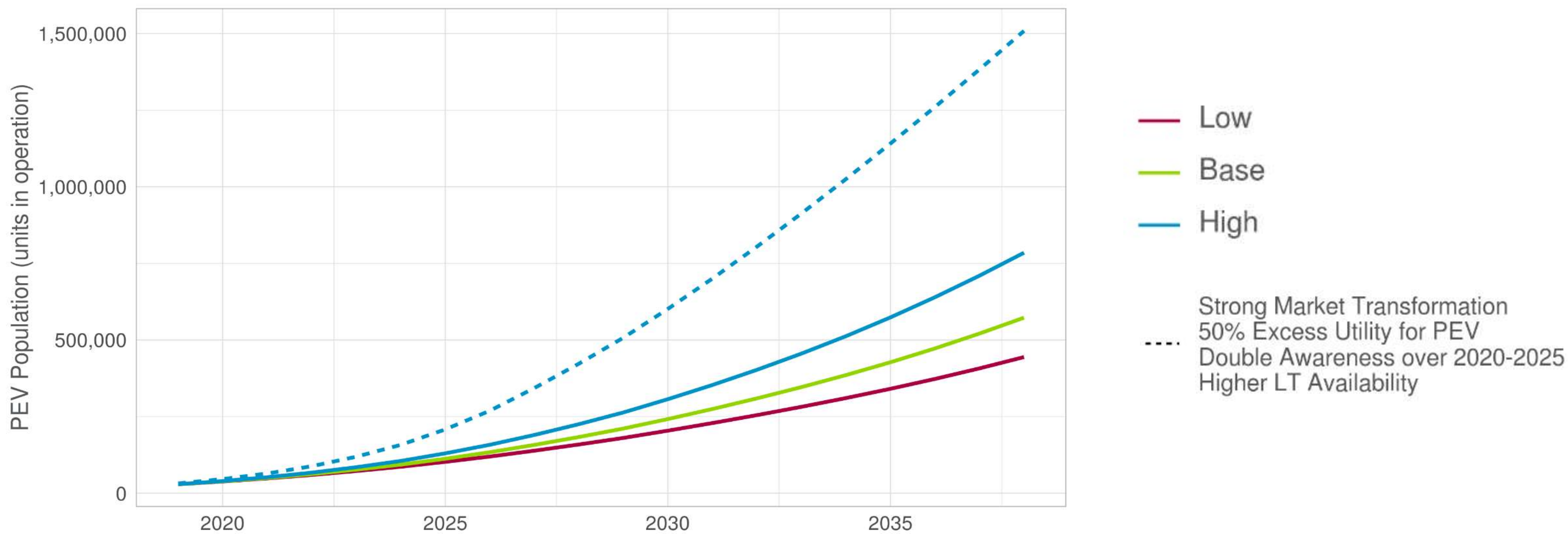
PEV POPULATION BY SCENARIO (STATEWIDE)

- Navigant forecasts statewide PEV adoption to reach nearly **575,000 vehicles by 2038** in the **Base** case under today's market conditions.
- Combining increased **utility, awareness, and availability**, in addition to the High scenario assumptions, increases the forecast to the **targeted 1.5 million PEVs in Arizona in 2038**.

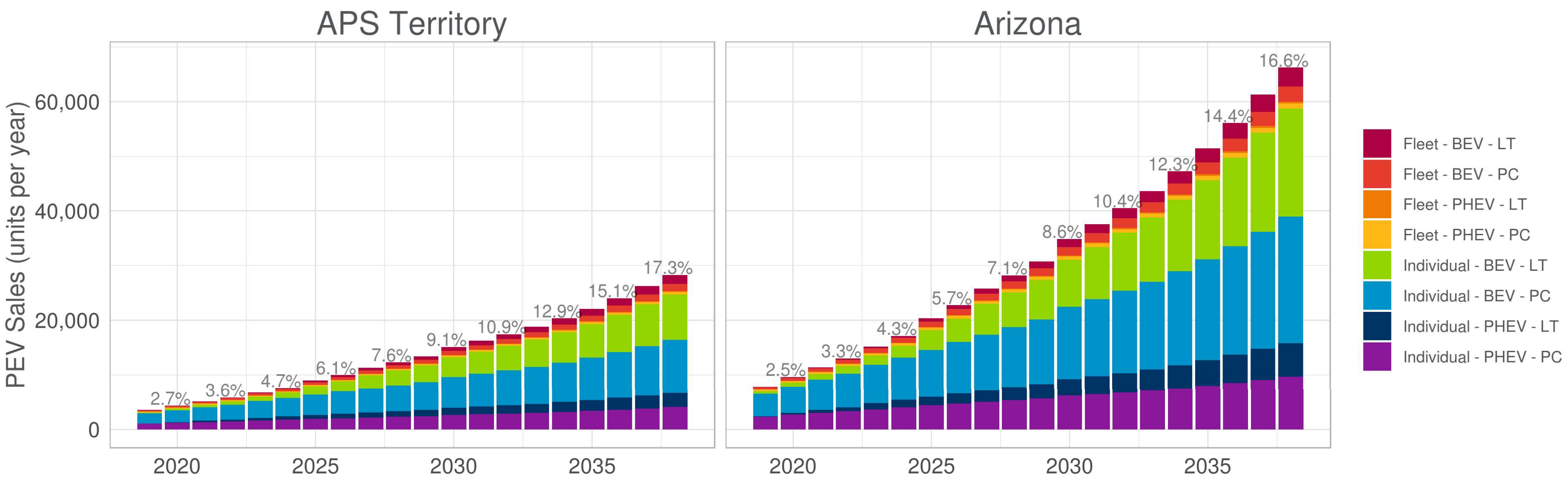


Source: Navigant

EV ADOPTION & CHARGING FORECAST

ANNUAL VEHICLE SALES FOR ARIZONA AND APS TERRITORY (BASE SCENARIO)

- APS Territory **market share** of sales (17.3% in 2038) is slightly ahead of the state as a whole (16.6% in 2038).
- PEV sales will be strongly influenced by the vehicle model **availability**. In early years, PEV sales fall mostly into the Passenger Car (PC) category because there are few PEV Light Truck (LT) models available. As automakers expand their lineup, PEV LT sales will increase.



Source: Navigant

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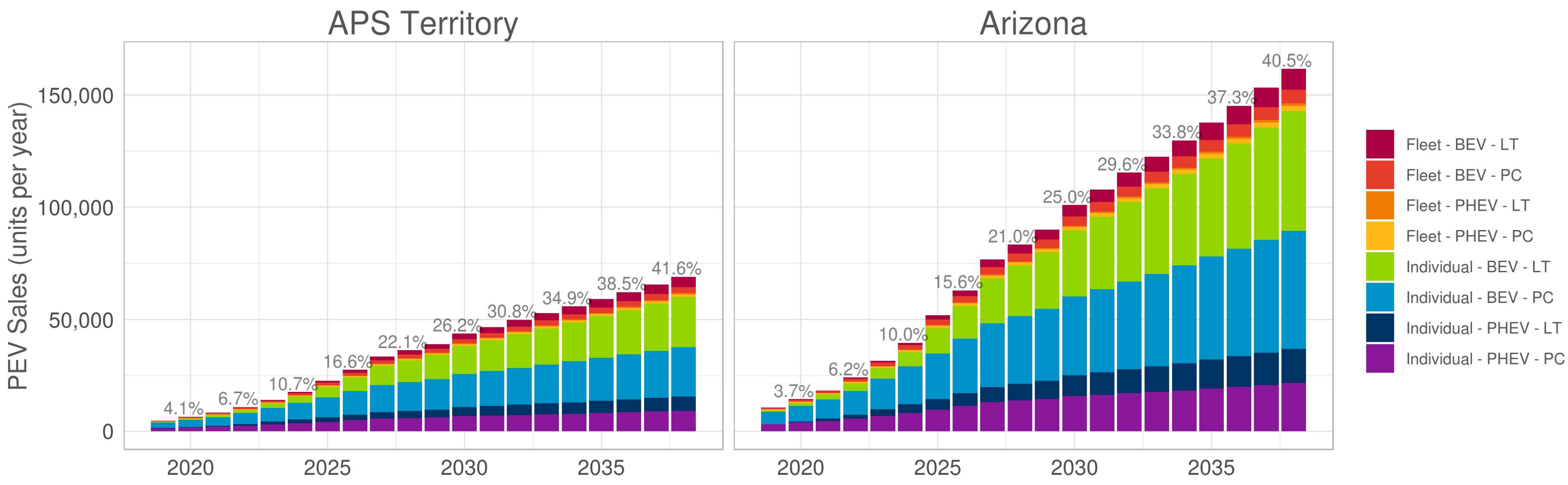
ANNUAL VEHICLE SALES FOR ARIZONA AND APS TERRITORY (STRONG MARKET TRANSFORMATION SCENARIO)

- PEVs will make up roughly 2% of sales in 2019 and grow to around 41% by 2038 in the **Strong Market Transformation** scenario.
- The Strong Market Transformation scenario displays a higher share of **Light Trucks** (LT) because the availability of these models is assumed to be greater and occur earlier as compared to the Base scenario.



Source: Navigant

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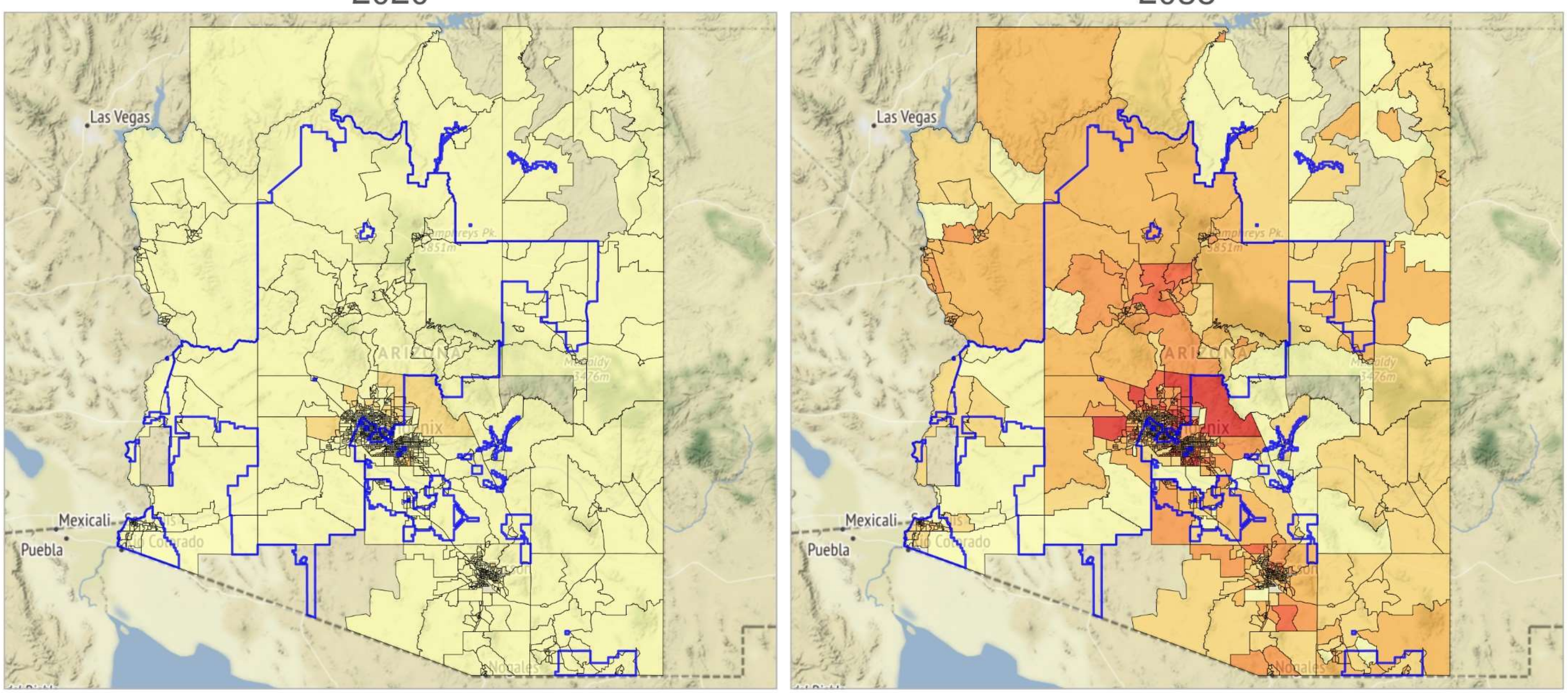
EV ADOPTION & CHARGING FORECAST

HEATMAP FOR PEV REGISTRATIONS (STATEWIDE)

PEV Population in Arizona

2020 | 2038



PEV Adoption is expected to be highest in major metro areas like Phoenix (next slide), and relatively uniform throughout the rural areas of the state.

Number of PEV by Census Tract
- 75-
- 250-
- 450-
- 730-
- 1,200-
- 2,000-
- 2,000+

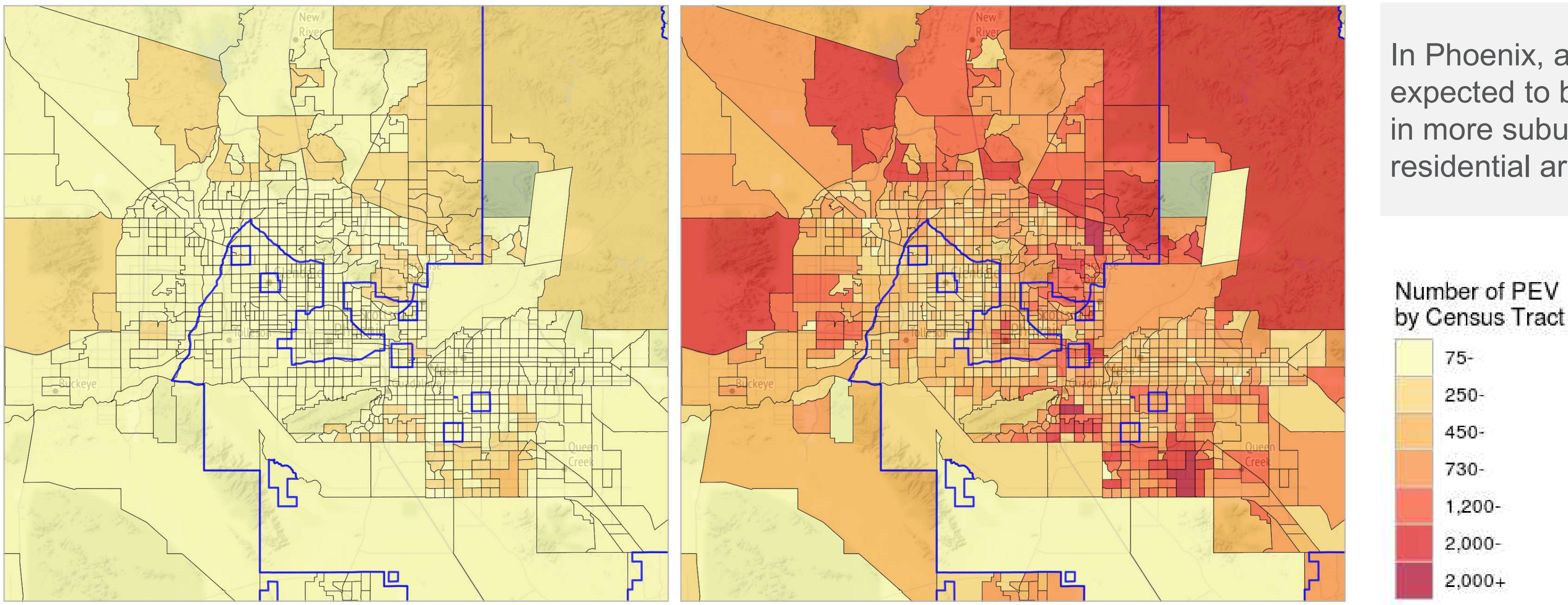
Source: Navigant

NAVIGANT

HEATMAP FOR PEV REGISTRATIONS (PHOENIX METRO)

PEV Population in Phoenix Metro

2020 | 2038



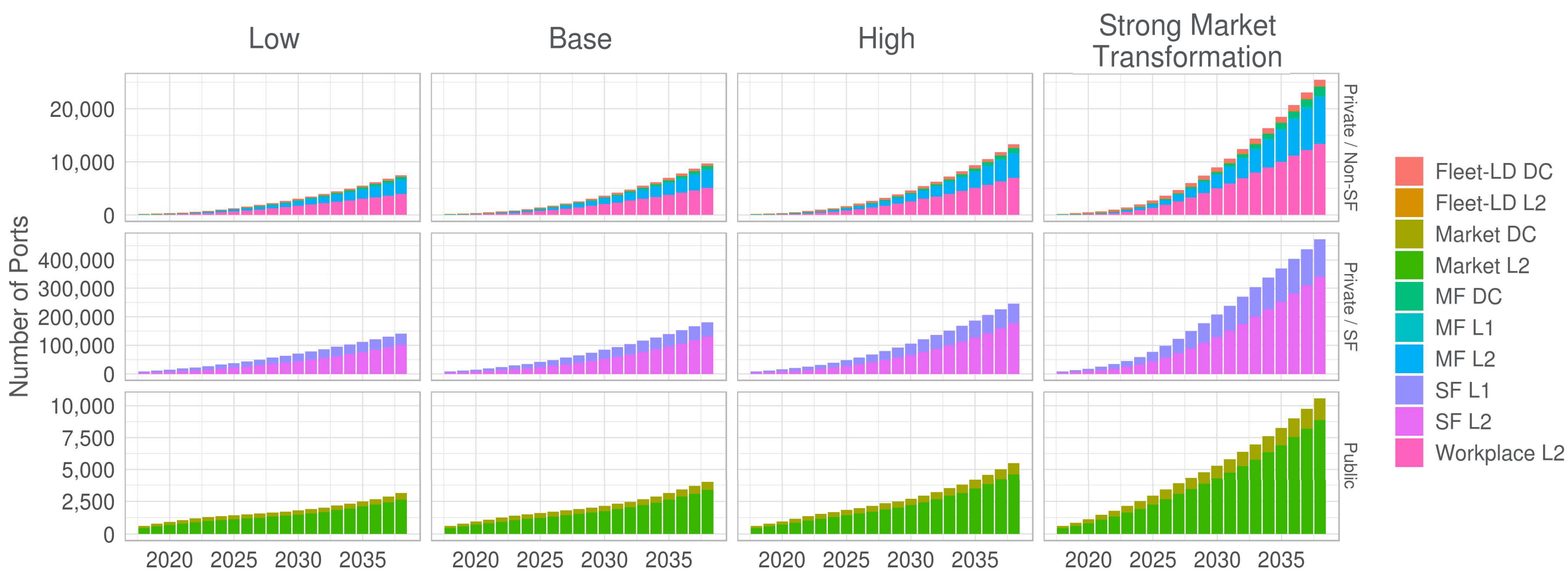
In Phoenix, adoption is expected to be higher in more suburban residential areas

Source: Navigant

NAVIGANT

TOTAL CHARGING PORTS BY SCENARIO, USE CASE, AND TECHNOLOGY (APS TERRITORY)

- The number of ports needed to support **single-family home charging** is over **40 times** the other use cases combined because of consumer preference for home charging.
- On the **public** side, **L2 ports** make up roughly **85%** of the public charging need.



Source: Navigant

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ADDITIONAL MODELING ASSUMPTIONS

Description	Value
Vehicle efficiency (ICEV)	Average fuel economy of 28.8 MPG in 2019, increasing to 30.5 MPG in 2038
VMT per vehicle (source: FHWA transportation survey for Arizona)	(see table below)
Battery prices (Note: these are proprietary to Navigant and for APS's internal use only)	Navigant Research updates advanced battery market growth and price forecasts on a regular basis through ongoing research and interviews. Forecasts are driven by industry supplier projections obtained through surveys and interviews. These forecasts are predicated on insight into the technology roadmaps for each interview supplier as well as their understanding of the competitive landscape.
Gasoline prices	Base Scenario: \$3.64 / gal in 2019, increasing to \$4.86 / gal in 2038 Low Scenario: \$2.73 / gal in 2019, increasing to \$3.64 / gal in 2038 High Scenario: \$4.55 / gal in 2019, increasing to \$6.07 / gal in 2038

VMT per vehicle (source: FHWA transportation survey for Arizona):

Powertrain	Class	VMT
BEV	LT	13,489
BEV	PC	11,160
ICEV	LT	11,140
ICEV	PC	10,459
PHEV	LT	13,489
PHEV	PC	11,160

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APPENDIX

ADDITIONAL MODELING ASSUMPTIONS

The VAST™ model considers several factors that determine market adoption:

1. **PEV Model availability** determines a maximum technical potential, which indicates how many models are available for purchase in the market.

2. **Consumer eligibility** determines the fraction of the total population with access to charging, either through installing personal chargers at home, or using public charging.

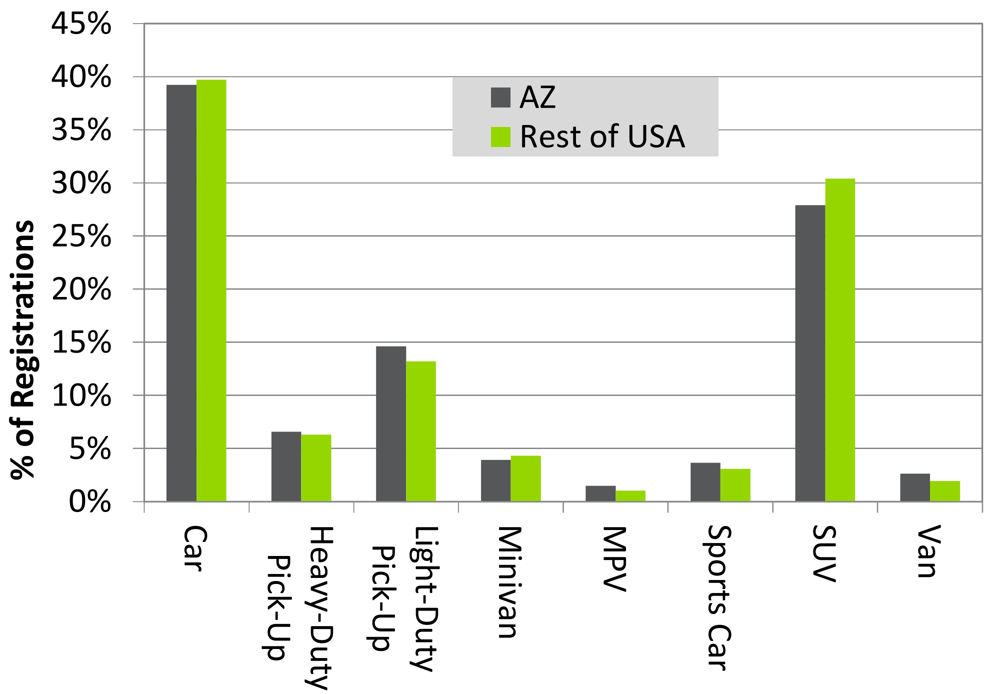
3. The **long run market share** is determined by the competing TCO between all of the powertrain options, using a customer preference function. This is where ***battery prices*** and ***gas prices*** are considered, and each one has a weight determined by how relevant they are for the TCO.

4. Finally, the **awareness level** determines how much of this long run market share becomes actual market share for PEV. Awareness indicates what fraction of the eligible population (i.e., those in single family homes or with access to public charging) will consider PEVs as an option when purchasing a new vehicle. This is a percentage value in the VAST™ Adoption Module, which is calculated by the Bass diffusion.

APPENDIX

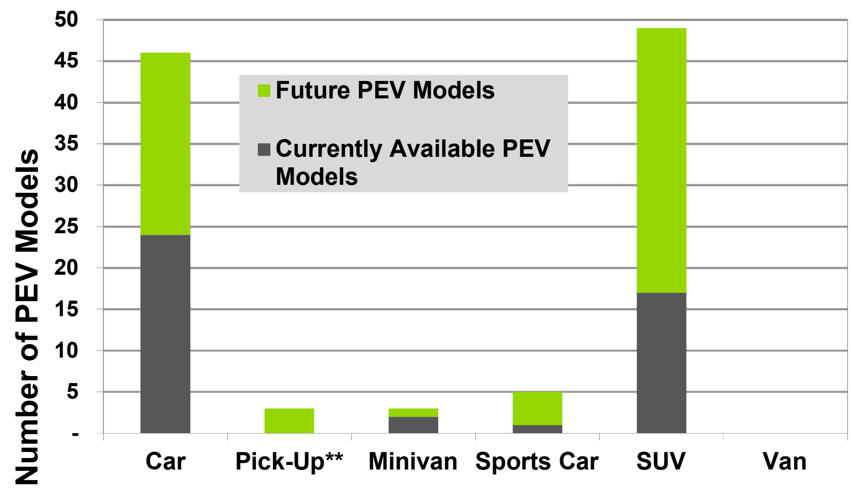
ARIZONA VEHICLE REGISTRATION TRENDS

Comparison of 2019 vehicle registration trends in AZ vs USA



Source: Navigant

- Arizona's vehicle body-type preferences are aligned with the rest of the US
- Passenger cars and SUV's make up two-thirds of AZ vehicles, and are the two body types with the most PEV model choices
- Pickup trucks make up more than 20% of AZ vehicles, and no PEV models are currently available



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GLOSSARY

Acronym	Definition	Acronym	Definition
AFDC	Alternative Fuel Data Center	MF	Multi-Family
BEV	Battery Electric Vehicle	MHDV	Medium and Heavy-Duty Vehicles
BEVMT	Battery Electric Vehicle Miles Travelled	NREL	National Renewable Energy Lab
DC or DCFC	Direct Current Fast Charger	PC	Passenger Car
EVI-Pro	Electric Vehicle Infrastructure Projection Tool	PEV	Plug-In Electric Vehicle
EVSE	Electric Vehicle Supply Equipment	PHEV	Plug-In Hybrid Electric Vehicle
ICEV	Internal Combustion Engine Vehicle	SF	Single-Family
L1	Level 1 EVSE	TCO	Total Cost of Ownership
L2	Level 2 EVSE	VAST™	Vehicle Adoption Simulation Tool
LD or LDV	Light Duty Vehicle	VMT	Vehicle Miles Traveled
LT	Light Truck	ZCTA	Zip Code Tabulation Area

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APPENDIX C

ENERGY EXEMPLAR RENEWABLE INTEGRATION STUDY

APS
Operational Cost of Renewable Integration

Energy Exemplar

PLEXOS AURORA

Energy Exemplar Overview

Global organization founded in 1999 with headquarters in Adelaide, Australia.

More than 100 employees across eight locations in North America, South American, Europe and Australia.

Serving 1,500 users in 52 countries at more than 300 sites.

In 2017, the Riverside Company became the majority stakeholder with a focus on growing the business into new markets.

Acquired EPIS in 2018, developers of a leading electricity forecasting and analysis tool with clients in North America and Europe.

Proven power market simulation tool that is a leader in modelling flexibility, efficiency, simulation alternatives and advanced analysis.

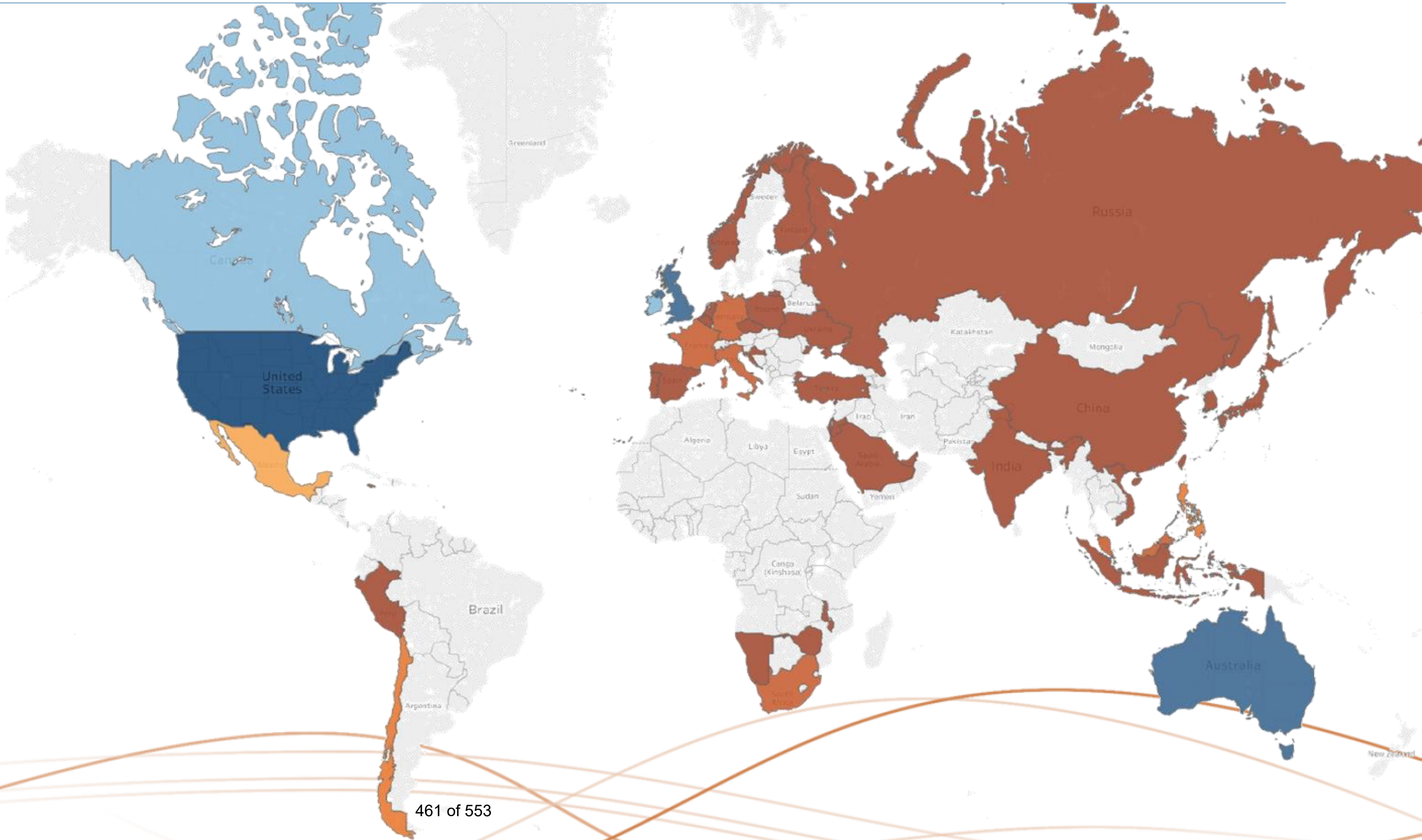
Client Portfolio

Clients by Region:

1 9 18 124

Clients by Segment:

Utility:	97
Consultant:	44
Power Producer:	39
Researcher:	28
Regulator:	21
TSO:	14
ISO:	13
Trader:	5
Energy Analyst:	4
International Institute:	3



Energy Exemplar

How is AURORA Used?

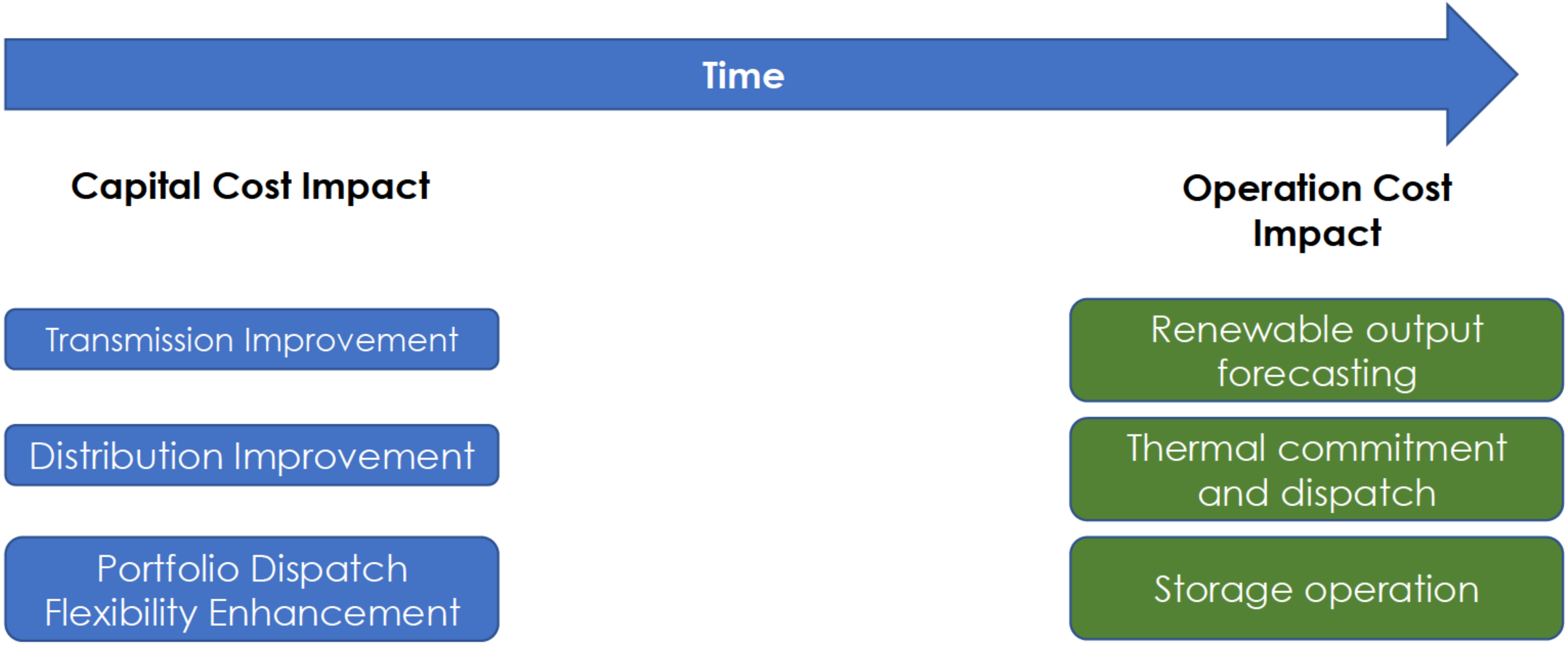
Generation Planning/ Budgeting	• Integrated resource planning • Budget projections • Detailed generator analysis • Assess RPS and environmental policies
Market Assessment/ Strategy	• Zonal & nodal price forecasting (hourly &/or sub-hourly) • Scenario based and probabilistic • Risk & portfolio analysis • Market design and policy analysis
Transmission Planning	• Frequency and value of constraints • Production cost impacts • Infrastructure studies
Portfolio Optimization	• Short term analysis (often nodal) • Highly optimal operational decision making • Highly automated (e.g. data feeds)

AURORA BY ENERGY EXEMPLAR

Study Objective

- Assess the Impact of Renewables on Generation Operation:
  - How does limited real-time adjustability of renewable impact Day-ahead and Real-time generation operation?
  - Does APS's projected dispatchable portfolio for 2030 and 2035 have the capability to compensate for renewable generation's limited real-time adjustability?
  - What is the excess generation operation cost of compensating for limited real-time adjustability of renewables?

Study Scope


Time
Capital Cost Impact
Operation Cost Impact
Transmission Improvement
Distribution Improvement
Portfolio Dispatch Flexibility Enhancement
Renewable output forecasting
Thermal commitment and dispatch
Storage operation

Study Assumptions

- APS will handle renewable operational impact without socializing the cost to neighboring regions
- APS will commit and dispatch its own resources to serve its demands
- There is no binding transmission constraint within APS territory
- Impact of forced outage, dispatchable deviation and load deviations are separate and not modeled.

PLEXOS AURORA

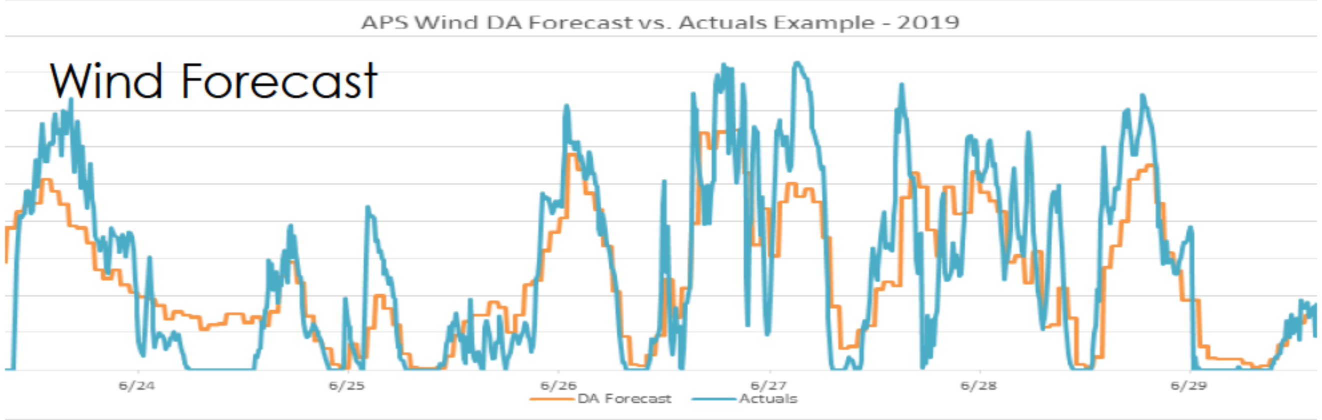
Modeling Forecast

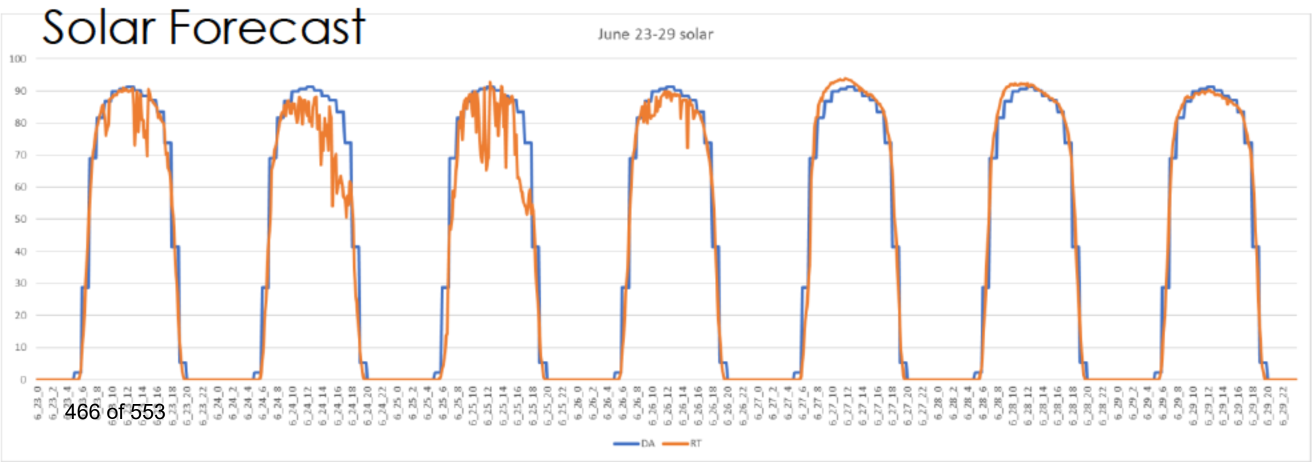
- **Portfolio level Forecast**
- **Day-ahead Forecast**

  Hourly renewable portfolio output expectation = avg of % of portfolio name plate capacity realized during comparable hour for 3 recent years

  Comparable hour is the same hour during each month
- **Real-time Actuals**

  Actual renewable portfolio output = % of portfolio name plate capacity realized each 10 minutes during a recent historic year





Aurora Operational Impact Modeling

	Day Ahead	Intra-day
Renewable	Forecast hourly →	Actuals 10 minute
Energy Storage	Dispatch hourly	Re-dispatch 10 minute
Quick Start Dispatchable	Commitment hourly Dispatch hourly	Re-commitment 10 minute Re-dispatch 10 minute
Non-QS Dispatchable	Commitment hourly Dispatch hourly	Fixed-commitment Re-dispatch 10 minute

Study Results

- Quick starting thermal resources are instrumental to providing sufficient flexibility to meet operational integration needs of APS's 2030 and 2035 renewable portfolios
- APS' currently projected portfolios for 2030 and 2035 have sufficient flexibility to meet solar and wind operational integration needs
- Holding operational reserves has little impact on operational integration cost.

Operational Integration Cost		
Resource Type	2030	2035
Solar	$1.28/MWh	$1.79/MWh
Wind	$2.89/MWh	$3.11/MWh

Additional Consideration

- Correlation between wind and solar volatility
- Correlation between load and renewable volatility
- Optimizing scheduled maintenance around integration needs
- Localized integration constraints and costs

APPENDIX D

CONCENTRIC NATURAL GAS MARKET STUDY

CONCENTRIC ENERGY ADVISORS

Natural Gas Market Assessment Stakeholder Presentation

Prepared For:

aps

May 2019

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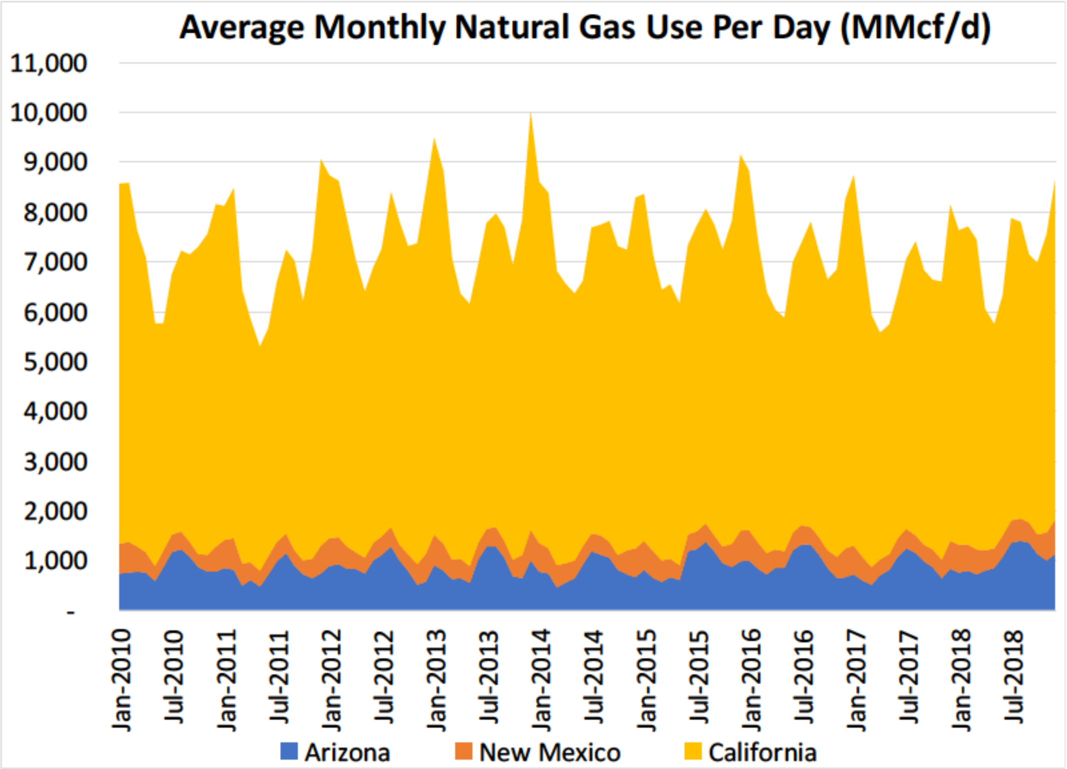
Natural Gas Demand

Desert Southwest and California

Natural gas demand in CA over 5 times larger than gas demand in AZ

- However, gas demand declining in CA as a result of increased renewables and energy efficiency
- Gas demand in Arizona and New Mexico is dominated by electric generation and may increase due to coal plant retirements



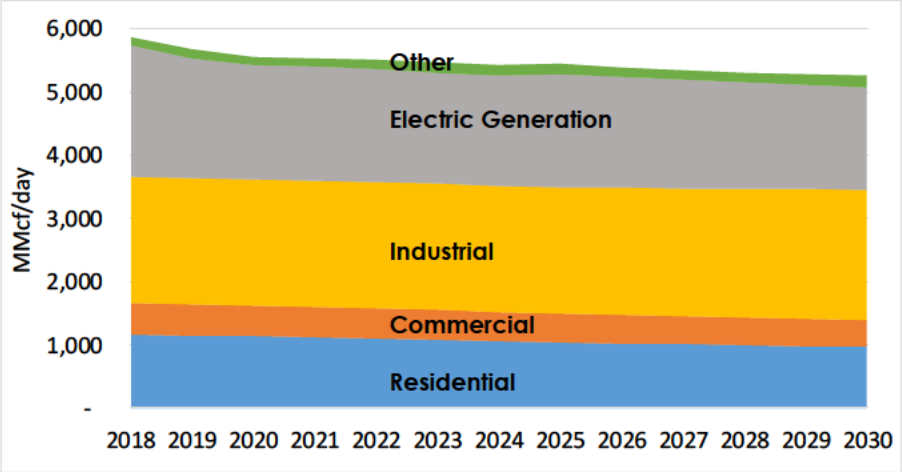
Source: EIA

Declining California Natural Gas Demand

State-wide natural gas demand expected to fall over 0.6 Bcf/d between 2018 and 2030

- Driven by declines in almost all sectors
- Larger decreases expected in southern CA v. northern CA
- Both annual and peak demand anticipated to decline over next decade
  - ~200,000 dth/d peak decline in southern CA

California Gas Demand



Source: California Gas Report

- This most recent outlook by the utilities in California reflects the anticipated impact associated with various factors:
  - Increasing renewables
  - Battery storage
  - Changes in R/C/I natural gas demand

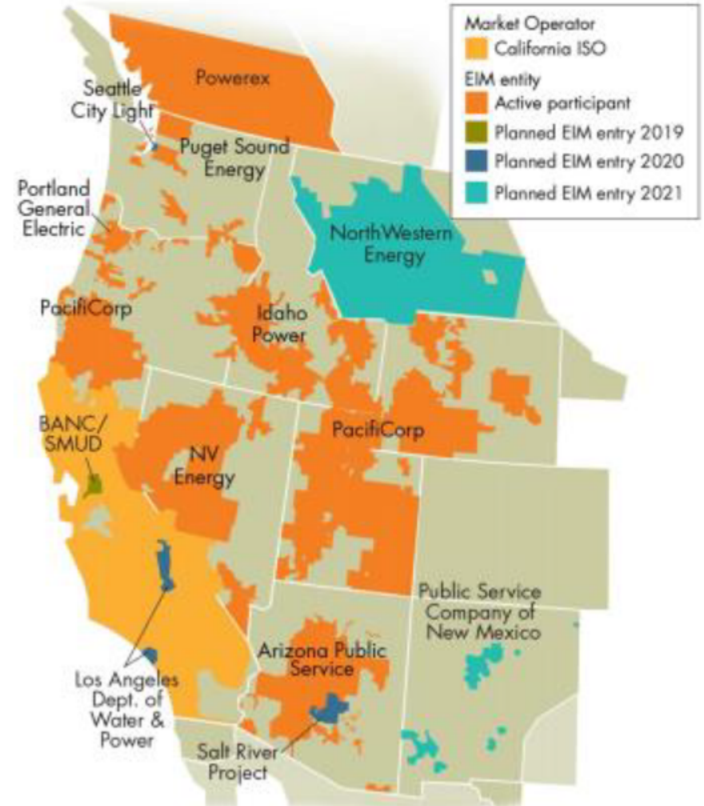
Impact of Coal Plant Retirements

Over 3,800 MW of coal retirements in AZ/NM could increase demand for gas

- Navajo (2,250 MW), San Juan (847 MW) and Cholla (767 MW) expected to retire within five years
- Upper bound of incremental gas demand ~ 0.6 Bcf/d
- Ultimate impact on natural gas demand a function of replacement facilities
- Significant additional coal capacity in AZ/NM (~4,500 MW) that do not currently have expected retirement dates within next 10 years
- Highly uncertain as to impact, if any, of the Affordable Clean Energy plan on coal plants in AZ/NM and potential future increases in gas demand
    - Much greater flexibility for coal plants to meet standards than Clean Power Plan
    - No specific formula proposed for establishing standards of performance
    - Potentially up to 3-years for State Implementation Plan filings
    - Likely subject to extensive and lengthy litigation

Energy Imbalance Market ("EIM")

- EIM increases the output of renewable resources and decreases the output of other resources, with focus on summer peaks
  - EIM impact on peak/annual natural gas use on western pipeline system unclear without more data and detailed analysis
- With EIM, CAISO has recognized that gas-fired resources are required for reliability/ ramping requirements
- Broader participation in energy imbalance market over time and increased coordination is likely to:
  - Place reduced reliance on western natural gas pipeline system on an *annual average* basis
  - May not have significant reduction on *peak* pipeline usage until battery storage becomes scalable/economic



Natural Gas Demand:

Other Demand Factors

Natural Gas Exports to Mexico

- Current forecasts far exceed previous expectations; 4.5 Bcf/d to 7.5 Bcf/d by 2025
- Dominated by south Texas
- Will influence gas prices, but lesser impact on pipeline capacity serving Southwest
- Mexican political policies to be a key influence over extent of impact

LNG Exports

- US LNG export capacity has increased rapidly in four years
- 0 Bcf/d at end of 2015; 10 Bcf/d at end of 2021
- EIA expects total LNG exports to average ~14 Bcf/d by 2030
- Most relevant proposed project to APS would be Costa Azul export facility if built

Renewable Portfolio Standards

- State-level mandates require significant growth in renewable generation over the next decade, which will compete with natural gas in generation mix
- RPS policies becoming more aggressive (CA & NM – 100% by 2045; NV – 50% by 2030)
- Should place downward pressure on Southwest gas prices
- However, pipeline capacity (with flexibility) will remain necessary to backstop variable renewables *until battery storage is sufficiently scalable*

Demand for Pipeline Capacity

El Paso Natural Gas ("EPNG")

- Transportation capacity on EPNG is currently effectively fully contracted
  - South Mainline is difficult to expand without considerable looping
  - Havasu Crossover (with San Juan supply) would require expansion of 400,000+ dth/d to be economic
- Potential that some capacity to California will not be renewed due to reduced gas demand
  - May provide opportunity for APS to secure additional mainline capacity on EPNG in the future
- Contracts with primary delivery points to California total ~ 2 Bcf/day

Transwestern

- There appears to be unsubscribed capacity on Transwestern from the San Juan basin through the Phoenix Lateral
- However, Transwestern is more constrained out of the Permian Basin

❖ ***The cost of any future pipeline expansions dependent on size and location of existing and new capacity requirements at the time***

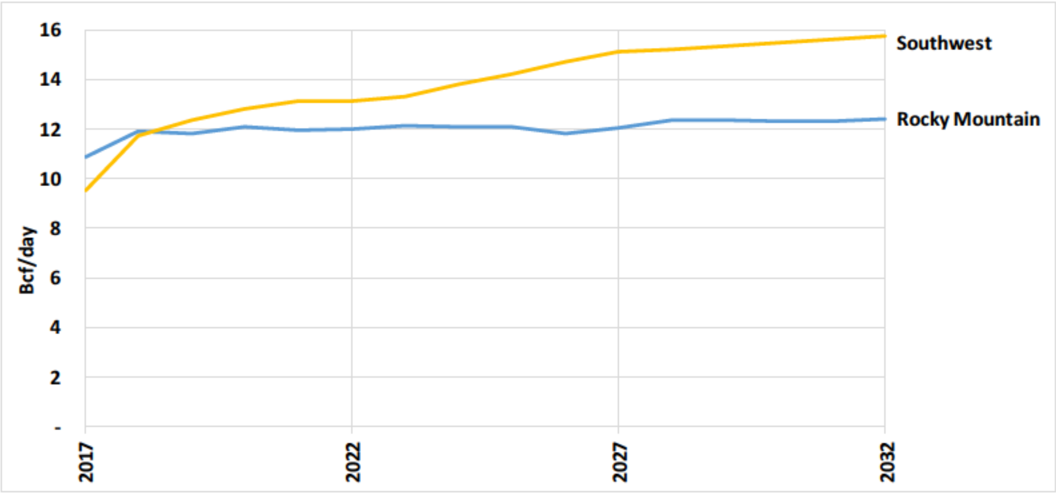
Natural Gas Supply

CONFIDENTIAL

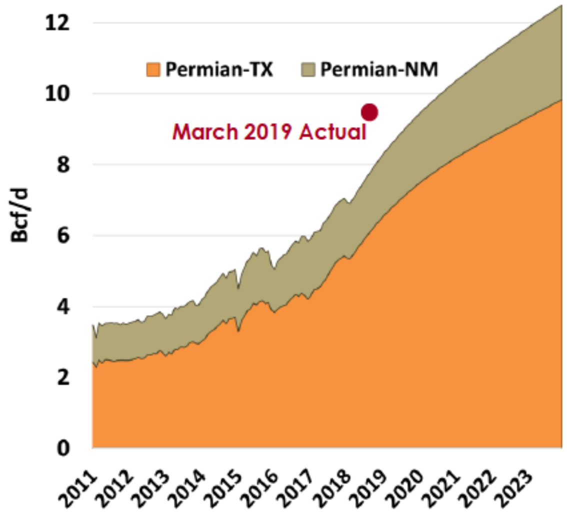
Permian Production Expected to Remain Strong

Permian growth expected to fully offset production declines in the San Juan

Dry Natural Gas Production



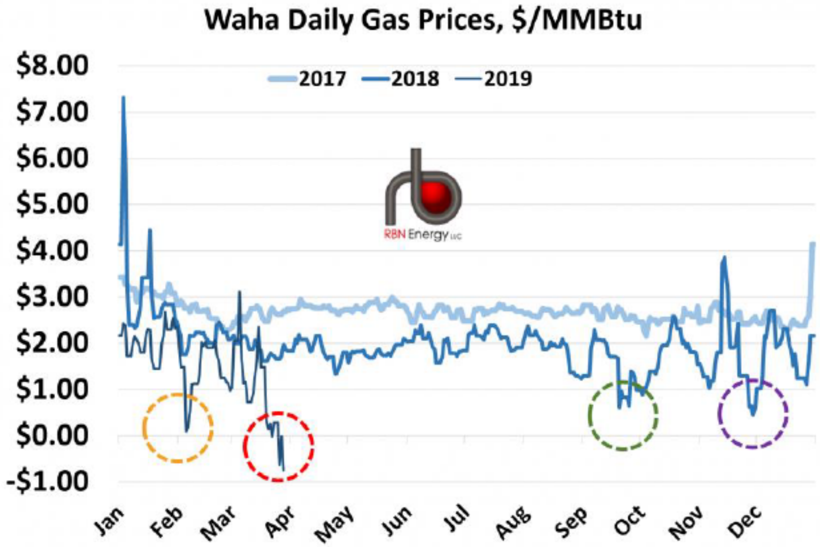
Source: EIA-AEO 2019

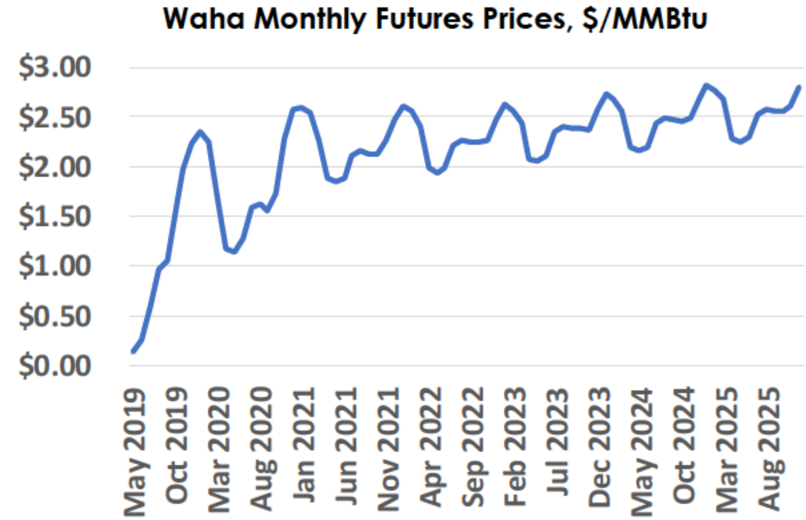


Source: RBN Energy

- Southwest production expected to grow at a rate of 2.1%/year through 2032 then level off and eventually begin to decline
  - Increases in the Permian Basin are function of oil prices rather than natural gas prices
- Major producers in the Permian continue to increase production outlooks
- Permian gas production expected to at least double between 2017 and 2023
- 2019 to date Permian gas production has been much higher than expected

Permian Production Price Implications





- Production increases in the Permian have exceeded increases in takeaway capacity, depressing prices to extremely low levels in late 2018 and early 2019
- Low prices/volatility to continue until additional take-away capacity is built:
  - *Wahalajara System*: 0.5 Bcf/d add'l takeaway capacity in MX (Spring 2019; Fermaca)
  - *Gulf Coast Express*: 2.0 Bcf/day; Permian to Agua Dulce, TX (late 2019; Kinder Morgan)
  - *Permian Highway*: 2.1 Bcf/day; Permian to Katy, TX (late 2020; Kinder Morgan)
  - Additional projects also proposed
- Even with new capacity, prices expected to remain under $3.00/dth through 2025

Natural Gas Reliability

WECC Report

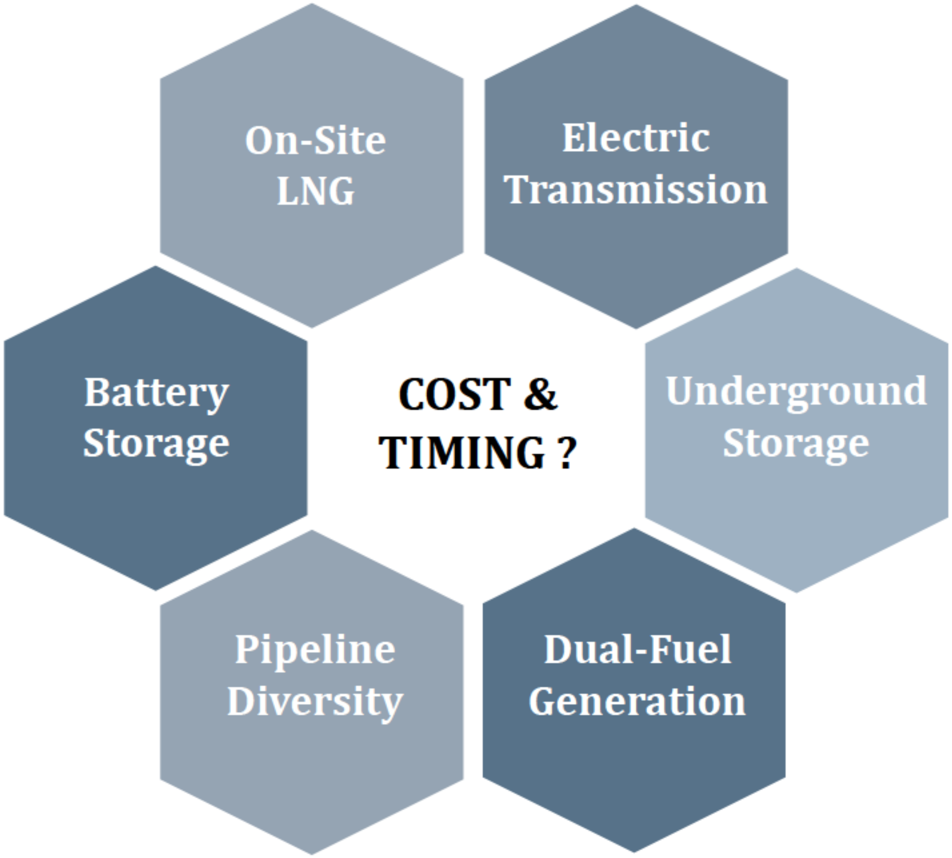
- In 2018, WECC commissioned a Gas-Electric interface study to assess risks of electric reliability associated with gas system disruptions in the West
  - Conducted due to operational/reliability issues associated with Aliso Canyon
  - Evaluated all of Western Interconnect; covered 2018-2026
  - Focus on pipeline (rupture) and supply (freeze off; seismic) disruptions assuming Aliso Canyon no longer in service
- Key Conclusions of WECC Report:
  - Retirement of coal/nuclear only partially offset by increased renewable generation
    - New gas generation creates an incremental 6.3 Bcf/d of demand across the region
  - Higher pipeline utilization expected, limiting daily operational flexibility on pipelines
  - Desert SW and California found to be particularly at-risk from disruptions to pipeline infrastructure due to:
    - lack of underground storage
    - relatively lower electric transmission interconnectivity
  - Freeze-off scenarios cause high utilization of electric transmission with potential reliability issues
  - Recommended a portfolio of solutions to address reliability (*i.e.*, pipeline and storage infrastructure; renewable generation; battery storage; DSM; dual-fuel generation)

Natural Gas Reliability:

Need to Balance Probability, Timing and Cost

The resource planning process needs to weigh the probability of reliability events against the timing and cost of mitigation

- Within an individual system (*e.g.*, APS system)
- More broadly (*e.g.*, across western interconnect)



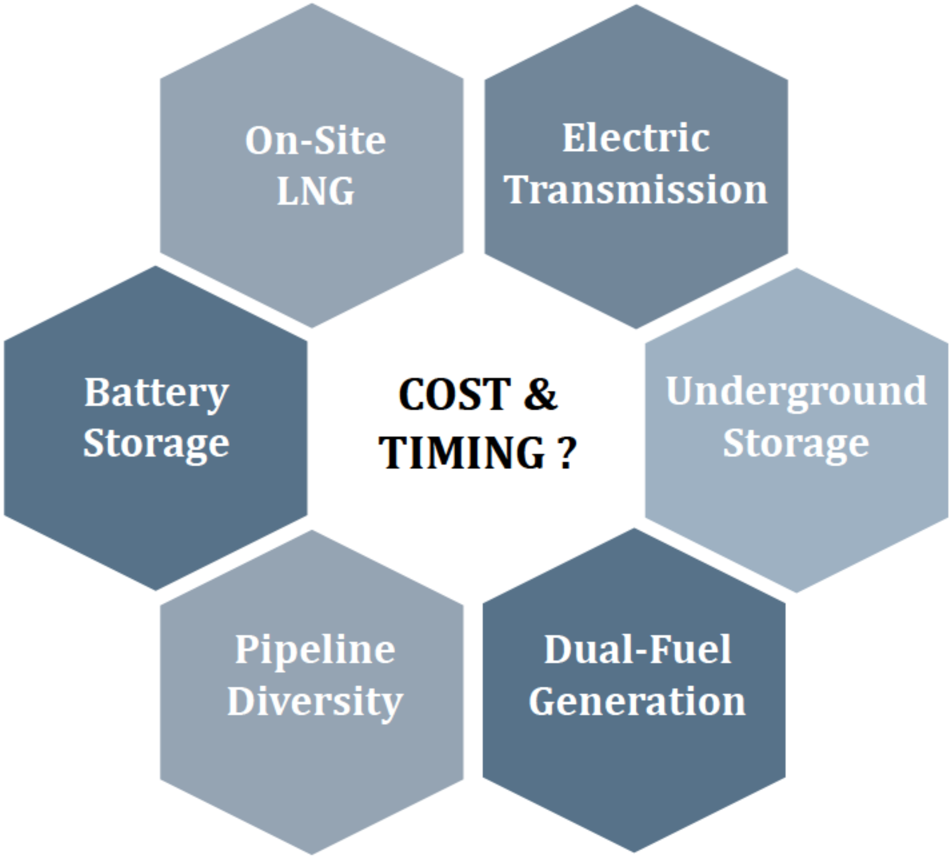
Need to Balance Probability, Timing and Cost

- Primary risks to maintaining natural gas reliability related to weather events and pipeline operations
- Weather-Related Events:
  - Freeze-offs are the most broad-based weather disruption for Permian supply; however, event in 2018 did not cause large scale problems
  - Other weather events not likely to affect Permian supplies transported west to NM/AZ/CA
    - Hurricanes only affect ability to transport Permian supplies east to Gulf of Mexico
    - Tornadoes more location-specific and not broad-based
- Pipeline Operations:
  - Reliability could be impaired if there was a significant, longer-term impact to pipeline operations
  - However, the interstate natural gas pipeline system is robust and the probability of an EPNG pipeline disruption modeled in the WECC Report was extremely low
  - Ultimately, the Desert SW's reliance on two long-haul pipelines (*i.e.*, EPNG and Transwestern) is no different than certain other areas of the US
    - For example, New England and Florida also heavily reliant on natural gas-fired generation with no native underground storage and served by few key pipelines

Natural Gas Reliability:

Need to Balance Probability, Timing and Cost

- All means of addressing potential natural gas reliability concerns require multi-year lead-times
  - Development time
  - Technology advancement
  - Regulatory approvals
- Costs can be significant
  - WECC Report estimated battery storage necessary to address EPNG rupture at ~ $12-18 *billion*
  - Salt cavern storage in AZ more flexible, but relatively costly (~$0.60 to $0.80/dth v. $0.34/dth for pipeline)
  - Southern AZ Reliability LNG project $80 million for ~ 3.5 days of 65,000 dth/d



- Also need to weigh long-term nature of asset and/or contractual investments in an uncertain and rapidly changing market

Impacts of Market Changes on APS's Natural Gas Portfolio

Existing APS Contracts Unaffected by Market Changes

- Numerous changes occurring that will impact natural gas demand in the Western gas market (potentially both increases & decreases)
  - (+) Power plant retirements, Costa Azul LNG, loss of Aliso Canyon
  - (-) Increasing RPS standdards/EIM participation

- These changes may affect the need for additional pipeline capacity in the future; however, do not affect APS's existing long-term contracts
  - Gas demand declines in California could create opportunity for APS to contract for additional pipeline capacity/flexible service if required
  - Magnitude of any new facilities required would affect cost of new pipeline capacity and thus rates for service on the new facilities

Importantly, if new pipeline capacity is required, the service quality, reliability, flexibility and rates of APS's existing transportation contracts would not be affected

- ✓ Reliability and rates cannot be affected per existing FERC policy
- ✓ Flexibility can only be modified through a FERC proceeding

Rate Impact of New Pipeline Capacity

- Pipeline capacity expansions generally require 15-20 year contracts to support new capacity
- FERC policy distinguishes rate impacts of new capacity between existing and new shippers
  - Incremental capacity generally results in transportation rates for new shippers that are higher than existing transportation rates
  - Rate impact on new shippers is a function of the cost of the new infrastructure required relative to the amount of incremental capacity created
- APS would not pay higher pipeline transportation rates due to capacity expansions *unless* APS contracts for service on an expansion project

FERC Policy
Pipeline Expansion/Rate Impact

- ✓ **No subsidization of new projects by existing shippers**
- ✓ **Costs of new infrastructure *not* allowed to be rolled-into existing rates unless:**
  - **Rates for existing shippers decrease; or**
  - **New facilities provide benefits to existing shippers (reliability; flexibility; replace existing capacity)**
- ✓ **Costs of new projects can be rolled-into existing rates in next rate case if doing will lowers existing shipper rates**

Pipeline Intra-day Flexibility

Importance of intra-day pipeline flexibility likely to increase in short-term

- Intra-day flexibility on pipelines is important to manage quick ramping needs and unscheduled takes of gas
- Increased intra-day flexibility likely to be required with increasing renewables until sufficient battery storage
- EPNG and Transwestern both provide intra-day flexibility
- APS contracts for FTH-8 service on EPNG, providing significant hourly flexibility
- Transwestern allows shippers to take gas over 16 hours at no incremental cost
- FERC policy prohibits EPNG to abandon the hourly services so long as there are contracts for the services

EPNG Hourly Take Flexibility	
FT-1	**Ratable 1/24th of MDQ in each hr**
FTH-3	**150% of 1/24th for 3 hrs (in a row) & 5 hrs (total)**
FTH-12	**150% of 1/24th for up to 12 hrs**
FTH-16	**150% of 1/24th for up to 16 hrs**
FTH-8	**Full MDQ in 8 hrs**

Pipeline Intra-day Flexibility

Existing hourly flexibility provided by EPNG unlikely to change; however, uncertainty as to future cost

- EPNG currently unable to increase existing hourly flexibility without new construction or market area storage because fully subscribed
  - Hourly flexibility in Phoenix area a function of capacity on the South Mainline and Phoenix lateral
- However, demand declines from downstream California shippers could create opportunity for APS
  - Ability for EPNG to provide increased FT-H service in future without any new construction required
  - Ability for APS to contract for additional service at existing rates
- Any future changes to EPNG transportation rates would require a FERC rate case (*and currently fixed through 2021*)

Greater Flexibility = Greater Cost

EPNG Hourly Svc. Rates	
FT-1	$0.34/Dth (max.)
FTH-3	110% of max.
FTH-12	117% of max.
FTH-16	125% of max.
FTH-8	200% of max.

Key Takeaways

Natural Gas Demand

- Natural gas demand in AZ & NM expected to remain strong in short-term driven by electric generation
- Demand declines over time in CA/NM due to meeting RPS goals and scalability of battery storage
- Timing/size of changes highly uncertain, but may provide pipeline capacity opportunity for APS without need for a pipeline expansion

Natural Gas Supply

- Permian natural gas prices currently below market due to pipeline constraints
- Additional capacity will alleviate constraints
- However, abundance of supply expected to keep Permian natural gas prices moderate for long-term

Natural Gas Reliability

- *Weather*: Freeze-offs, not hurricanes, are event to consider for reliability of SW gas markets
- *Pipeline Rupture*: APS's risk related to reliance on natural gas not seen as materially different than certain other areas in US even more reliant on gas-fired generation
- Need to weigh the probability of reliability events against the timing and cost of mitigation

Impacts of Mkt Changes

- The service quality, reliability, flexibility and rates of APS's existing pipeline contracts would not be affected if existing pipelines require expansion
- APS only subject to cost increase of an expansion if it contracts for additional capacity that requires an expansion
- Any additional future flexibility would require contracting for additional capacity that may or may not require a pipeline expansion

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APPENDIX E

ITRON
LOAD STUDY

APS MODEL REVIEW

February 7, 2020

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Itron

AGENDA

» Project Work Scope
» Principal Conclusions
» Residential Forecast
» C&I Forecast
» Data Center Forecast
» Peak Forecast

WORK SCOPE

» Itron will review four components of APS's forecast.
  - Residential Model
  - Commercial and Industrial Model
  - Data Center Forecast
  - System Peak Model

» Final Report

» On-Site Presentation (2)
  - February 7, 2020
  - Future Stakeholder Meeting

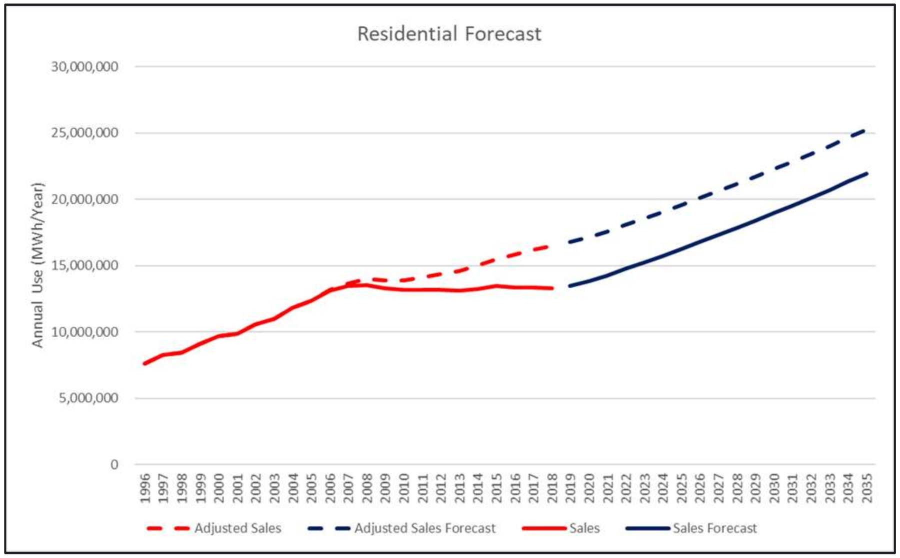
Key Assumptions and Disclaimer:

- Itron's review considers forecasting technique and model reasonableness. Itron did not review specific input assumptions such as historic data for sales, customers, weather, DSM, DG, and economic forecasts.
- Itron reviewed APS's 2019 Q3 Load Forecast, not the IRP forecast (2020 Q1 forecast).
- Itron recognizes that there are multiple ways to develop forecast models. Itron's support of APS's methods does not imply that APS's methods are the only way to develop a reasonable forecast. Different models will generate different forecasts.

PRINCIPAL CONCLUSIONS

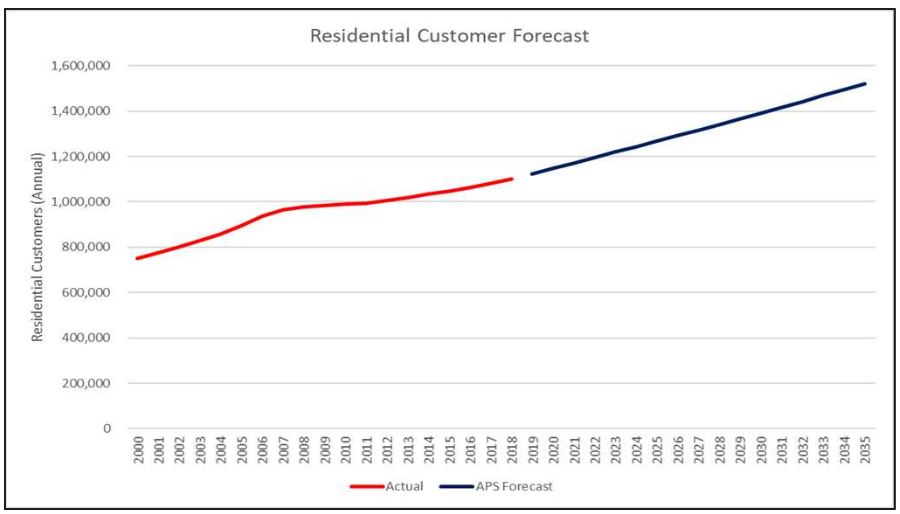
- Methods are consistent with industry practices and produce reasonable results given the input assumptions.
- The primary drivers are:
  - Residential Customers: Households
  - Residential Average Use: Real Personal Income
  - Commercial and Industrial Use: Occupied Square Footage
  - Data Centers: Customer Knowledge
  - Peak: Summer Adjusted Energy
- Itron finds that the modelling approaches for residential customers, C&I usage, data centers, and peak are reasonable.
- Itron recommends that APS revisit the residential average use model assumptions to remove the apparent inconsistencies.
- Since this review, APS has revised their residential model considering this project’s recommendation.

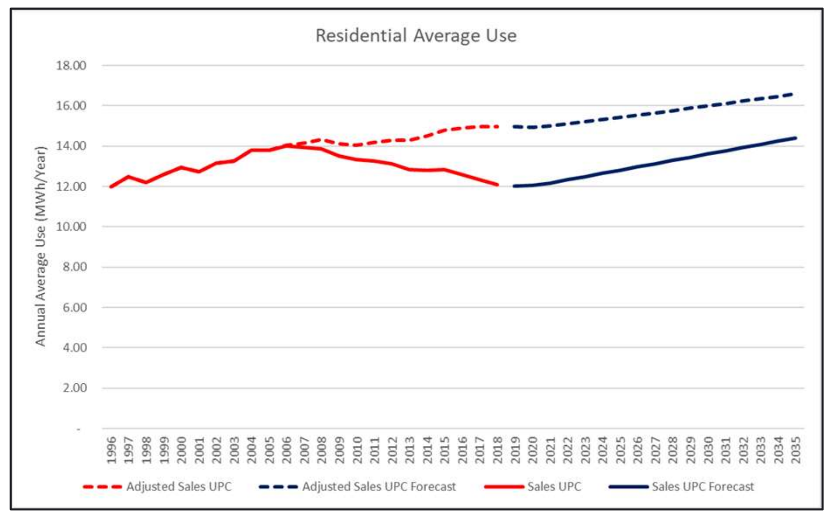
RESIDENTIAL FORECAST



Sales = Customer Counts x UPC

- Customer Counts is a judgmental model based on household forecast.
- UPC (Average Use) is an econometric model on adjusted UPC based on real per capita personal income.
- Modelling shows some instability which has been addressed in the IRP.
- Forecast in the range of possibilities





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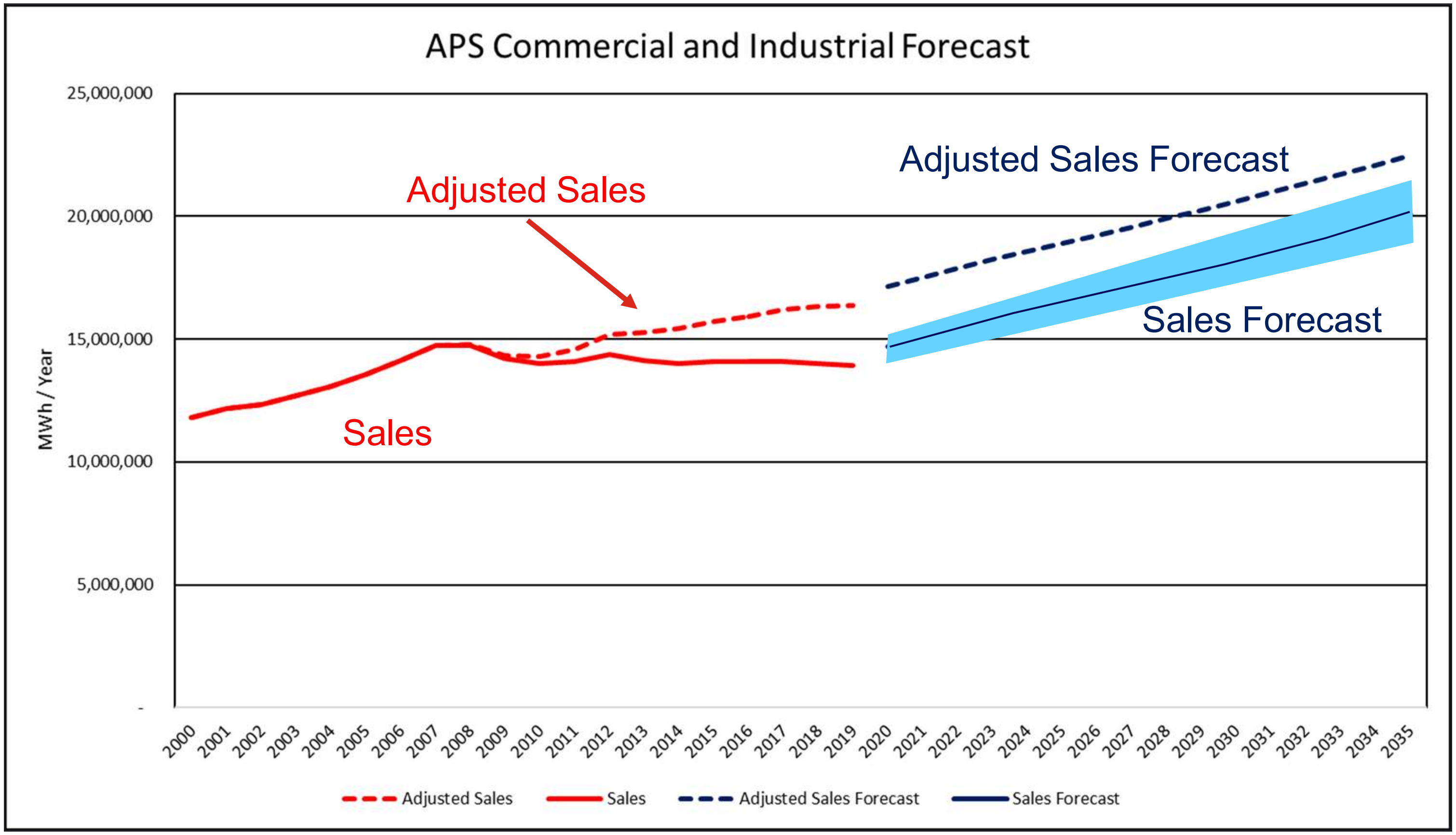
C&I ENERGY FORECAST



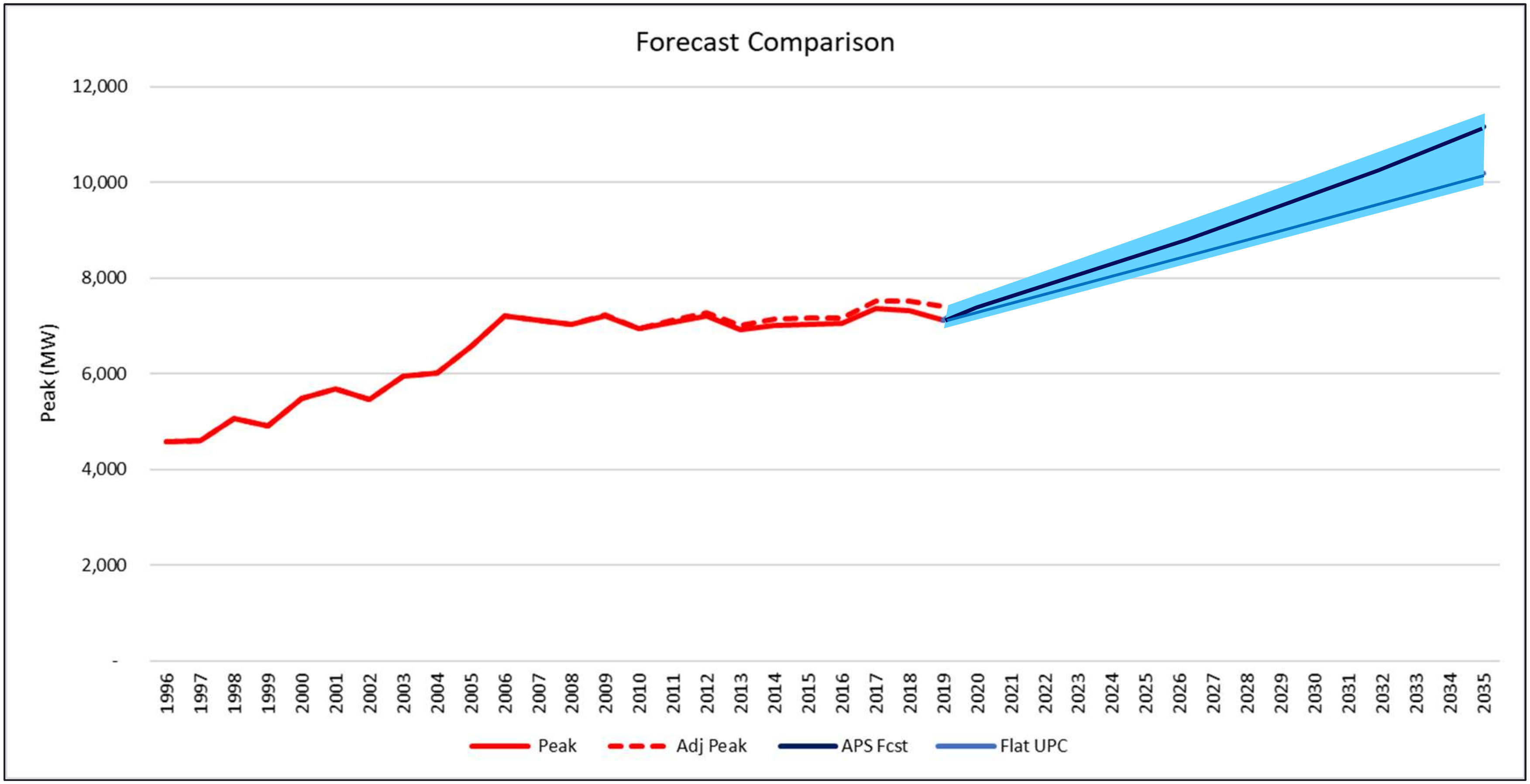
- Econometric model on adjusted sales (Add Back Method)
- Primary growth driver is occupied commercial building square footage
- Forecast in the range of possibilities

Itron

DATA CENTER FORECAST

- Data centers should be forecast separately from classes.
- Data centers should rely on APS customer specific knowledge.

PEAK FORECAST



- Peak Model uses a load factor method.
- Flat UPC Scenario assumes customer growth only and APS actor forecast.
- Peak forecast in the range of possibilities.

SUMMARY OF REVIEW

Forecast Area	Key Driver	Conclusion
Residential Energy Forecast		
Residential Customer Forecast	Households	🟢
Residential Average Use Forecast		
Statistical Forecast	RPI	🟡
End-Use Forecasts	Various	🟢
Base load Forecasts	Residual	🟡
Commercial Energy Forecast	Occupied Square Footage	🟢
Data Center Energy and Peak Forecast	Customer Knowledge	🟢
System Peak Forecast	Summer Sales	🟢

🟢 Itron support APS's forecast approach and results.

🟡 Itron recommends APS revisit the forecast assumptions to improve the approach and results.

BACK UP SLIDES

COMMERCIAL AND INDUSTRIAL FORECAST

Itron

APS CURRENT C&I MODEL

Estimation Period: June 2004 to June 2019

<u>Y Variable:</u>
Sales (MWh)
Actual Sales without DSM and DE (Add Back Method)

<u>X Variables:</u>
Space: Occupied Square Footage
Heating Space: Space x HDD
Cooling Space: Space x CDD
Real Price x Space: Space x Real Price
Real prices are assumed constant in the forecast period.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.953853
R Square	0.909835
Adjusted R Square	0.907774
Standard Error	50054.93
Observations	180

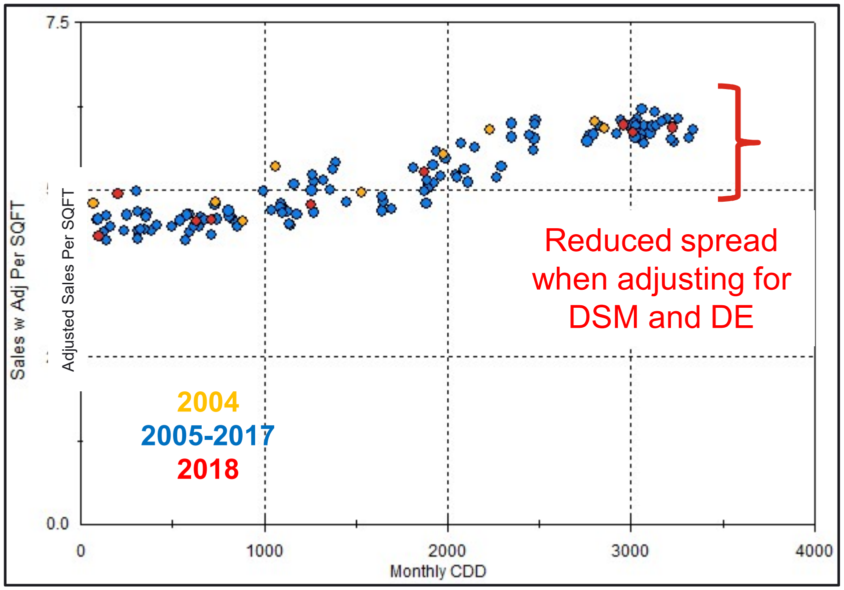
ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	4	4.42443E+12	1.10611E+12	441.4726	2.97E-90
Residual	175	4.38462E+11	2505496430		
Total	179	4.86289E+12			

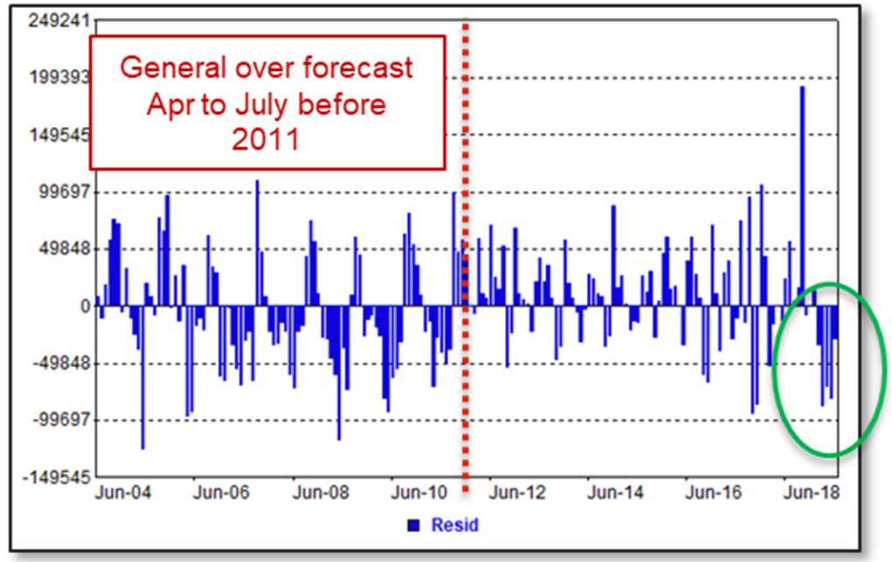
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*ower 95.0%*	*pper 95.0%*
Intercept	192658.3	63178.00482	3.049451625	0.002649	67969.37	317347.2	67969.37	317347.2
Space	3.796951	0.40923	9.278281336	6.5E-17	2.98929	4.604613	2.98929	4.604613
Heating Space	0.000794	0.000180785	4.394326106	1.92E-05	0.000438	0.001151	0.000438	0.001151
Cooling Space	0.000541	1.73151E-05	31.26343558	1.55E-73	0.000507	0.000576	0.000507	0.000576
Real_Price x Space	-4.24595	3.317710528	-1.279783614	0.202315	-10.7938	2.301923	-10.7938	2.301923

Itron

MINOR MODEL ISSUES



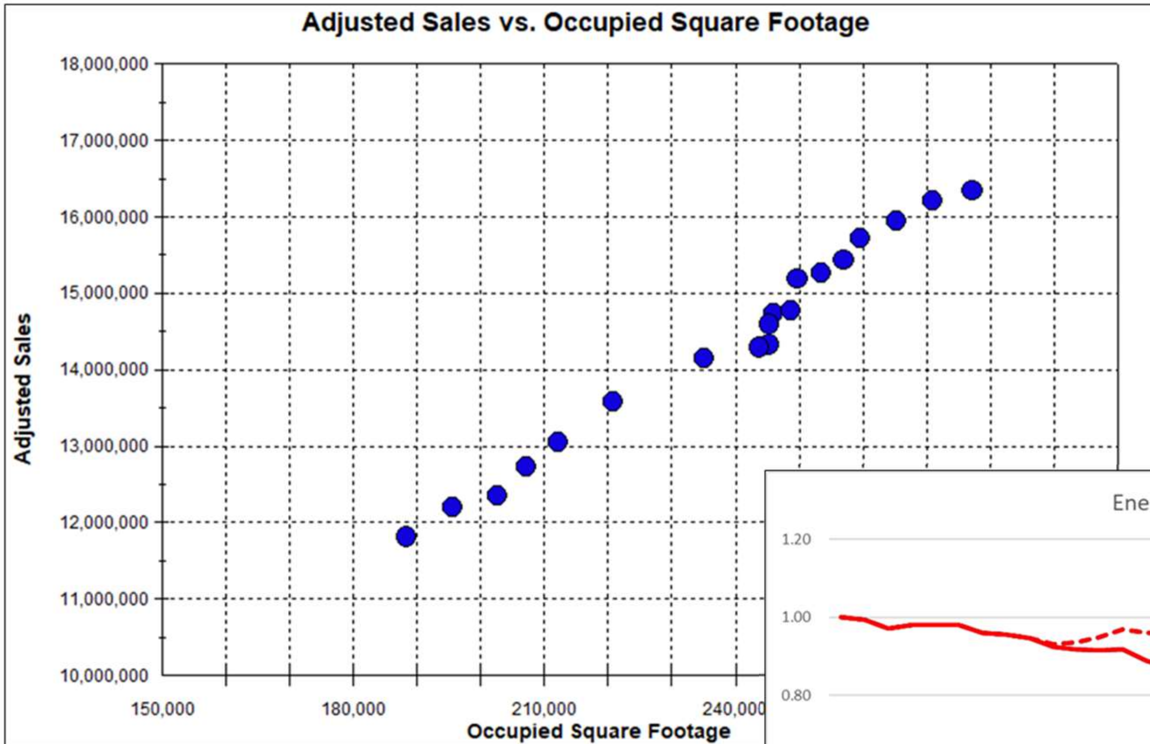
- Cooling response is not purely linear; flattening response around 2,500 CDD/month



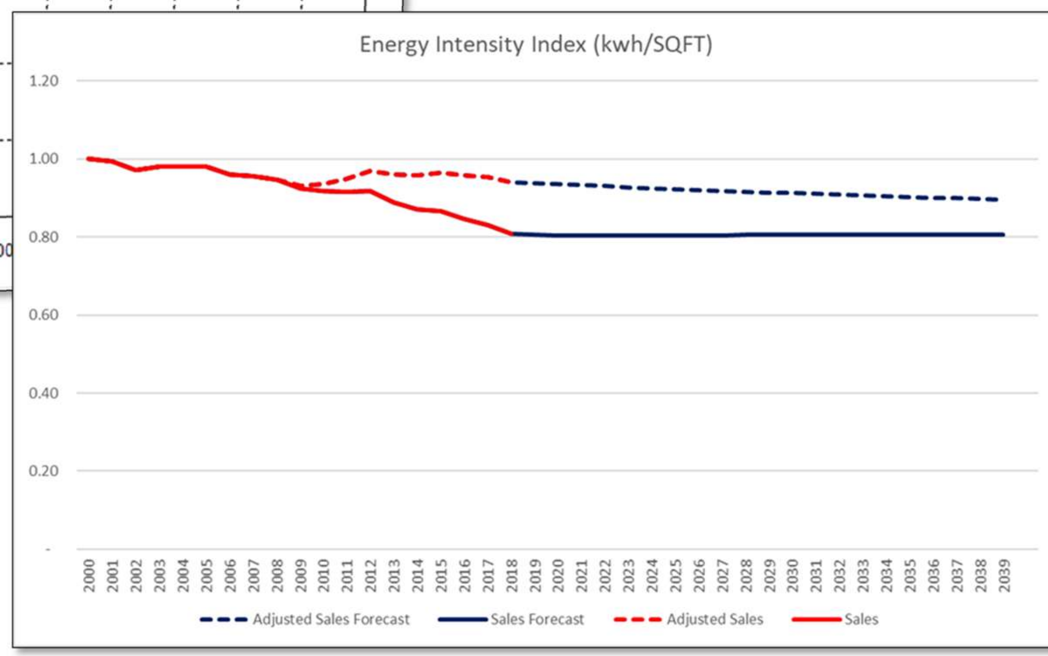
- Cyclical residual pattern before 2011.
- Slight over forecast (forecast above actuals) beginning in 2019

Correcting model issues does not change the forecast growth rates

SQUARE FOOTAGE RELATIONSHIP



- Occupied square footage is a strong driver
- Very linear relationship with sales



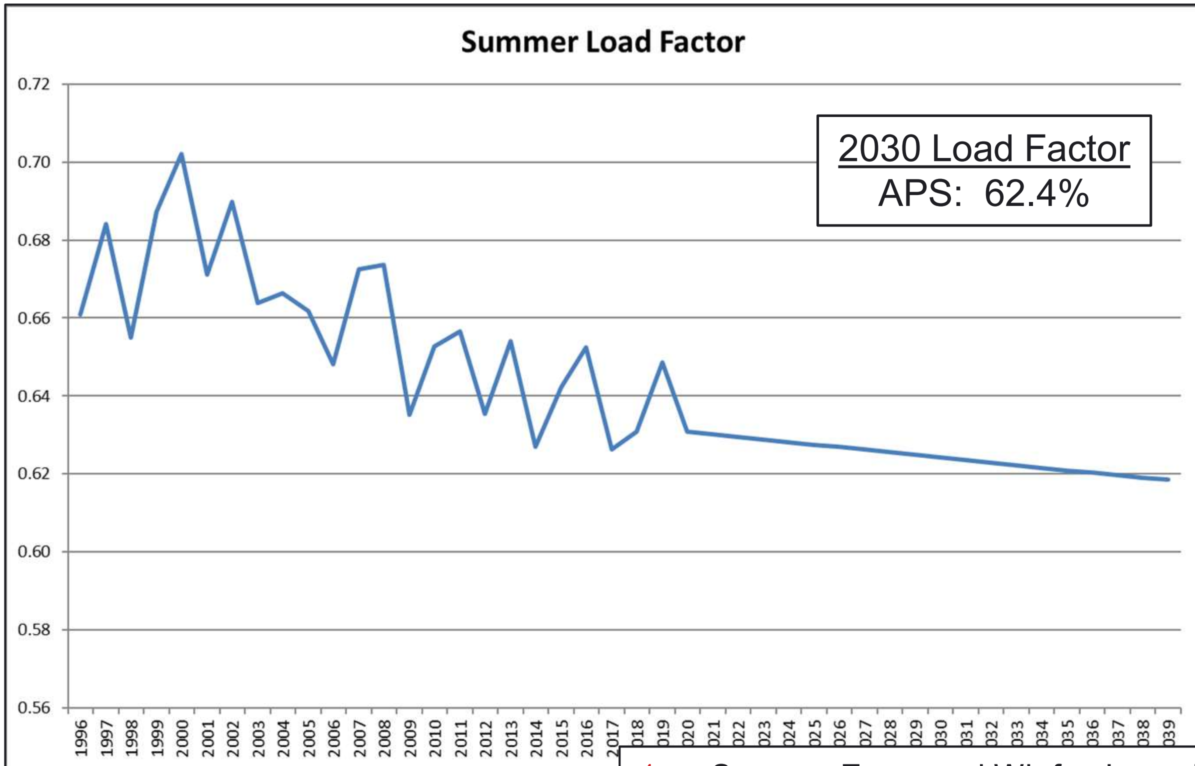
- Intensity (kwh/sqft) shows improved efficiencies

C&I FORECAST CONCLUSION

- Models shows strong statistical fit. Any identified corrections will not impact overall growth trajectory.
- Occupied square footage is a strong driver with a solid historic relationship to sales.
- Forecast intensities shows improved energy efficiency.
- APS forecast sits in the range of Itron tested models.

SYSTEM PEAK FORECAST

PEAK METHOD



1. Summer Energy = kWh for June, July, August
2. Adjusted Summer Energy = Summer Energy + DG
3. Peak = Max load for year
4. Adjusted Peak = Peak + DG
5. Adjusted Load Factor = Adjusted Summer Energy /(Adjusted Peak x 2208 Hours)
6. Linearly trend Adjusted Load Factor down to 61.9% in 2039

2019 Load Factor

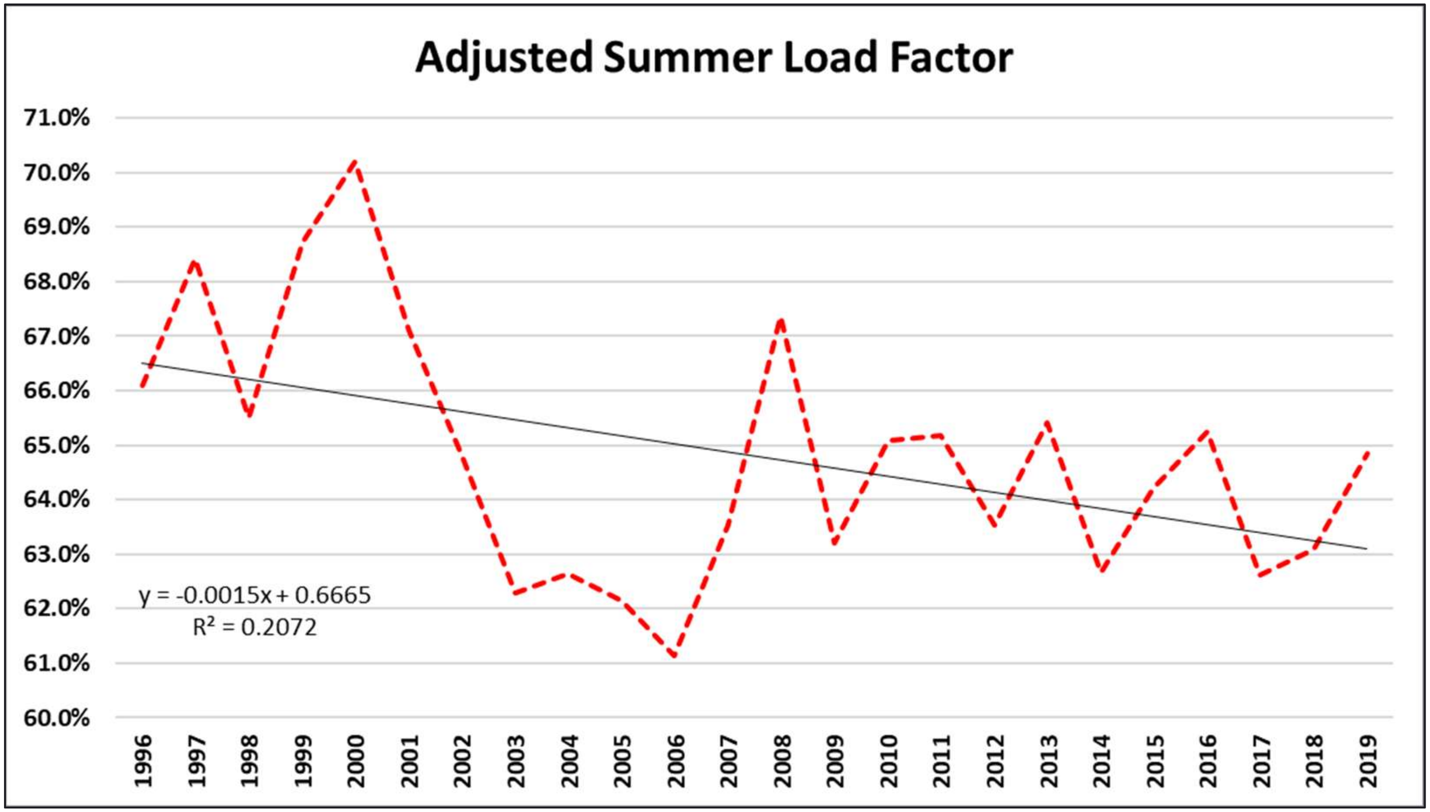
Load Factor drops 0.066% per year

$$\frac{63\% - (64.9\% - 0.6\%)}{19} = -0.066\%$$

Number of Forecast Years

Itron

LOAD FACTORS



- Equation: 1996-2019 Data; 2020 Load Factor = 63.1%
  - 2010-2018 Average Load Factor = 64.2%
  - 2014-2018 (5 Year) Average Load Factor = 63.6%
- APS 2020 Forecast Load Factor = 63.1%

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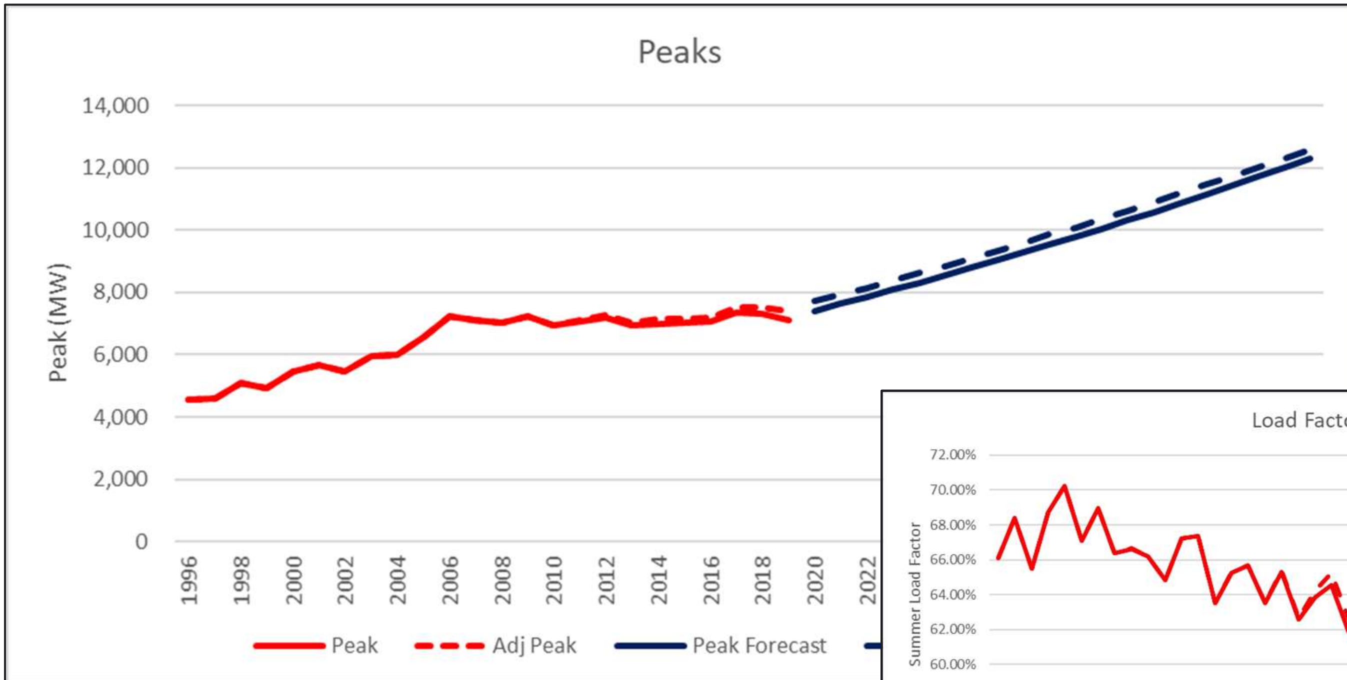
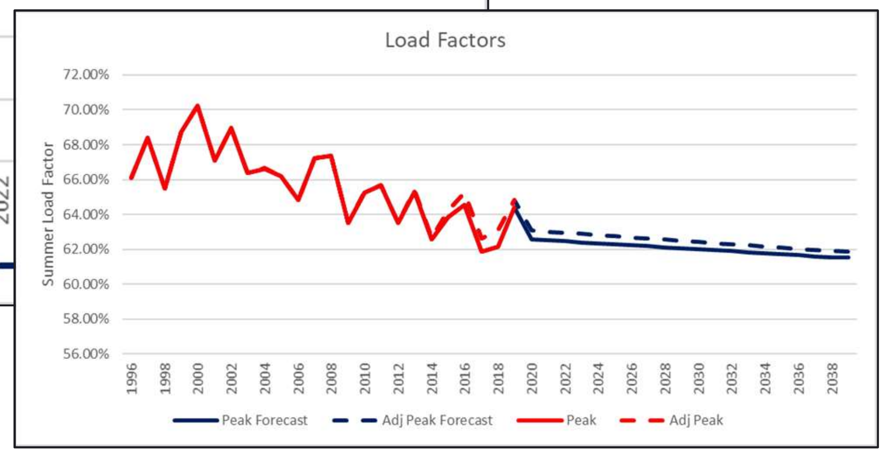
APS PEAK FORECAST





2010-2018	
Customers:	1.3%
Adjusted Summer Energy:	0.4%
Adjusted Peak:	0.5%
2020-2039	
Customers:	1.9%
Adjusted Summer Energy:	2.4%
Adjusted Peak:	2.7%

Growth is driven by energy

Itron

PEAK MODEL CONCLUSIONS

» Load Factor method is used by other utilities.

» Distributed Generation adjustment is common.

» The energy forecast is the primary driver in the peak forecast. If the peak forecast appears high or low, it is because the energy forecast appears high or low. Historically, the peak to energy relationship is consistent.

» APS's forecasted load factor reduction is consistent with history and a secondary driver compared with energy. The forecasted load factors are within the range of possibilities considering the historic decline.

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DATA CENTER FORECAST

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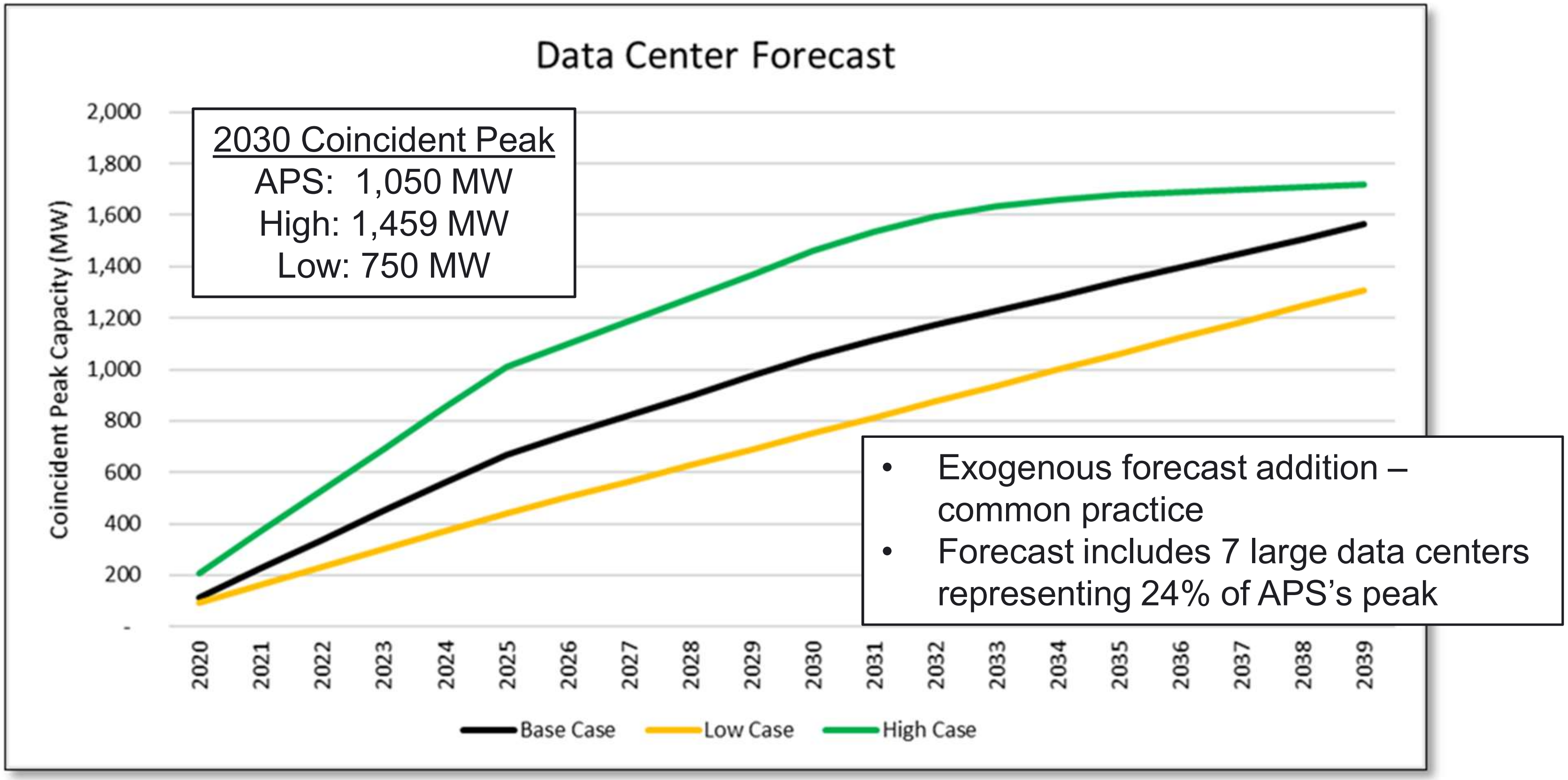
DATA CENTER FORECAST



<u>Data Center Forecast Conclusion</u>

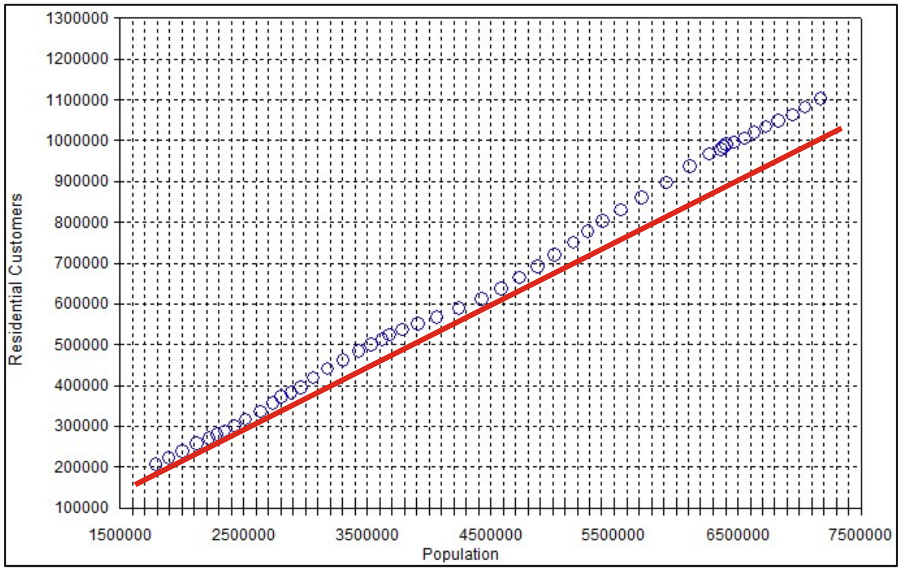
- Data centers should be forecast separately from classes.
- Data centers should rely on APS customer specific knowledge.

RESIDENTIAL FORECAST

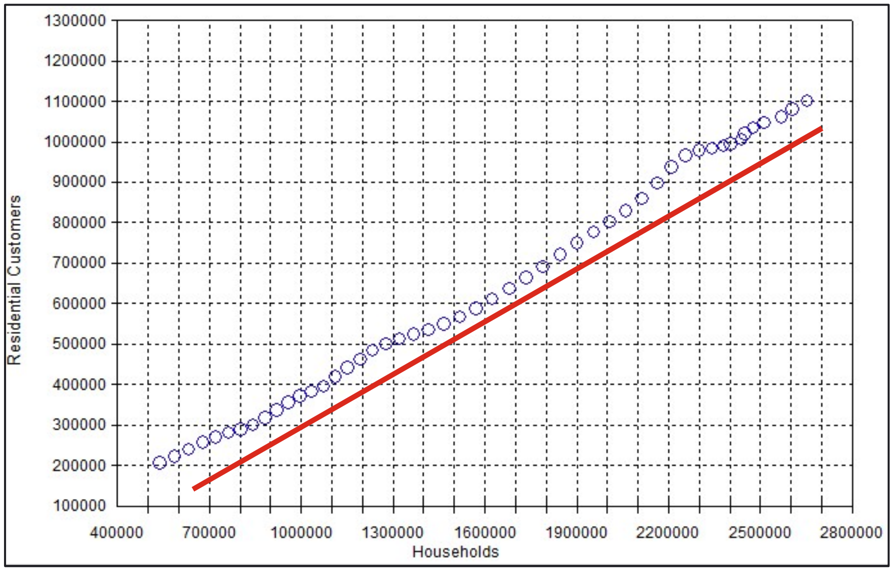
RESIDENTIAL CUSTOMER MODEL

RESIDENTIAL CUSTOMER DRIVERS

Customers vs. Population



Customers vs. Households



- Data from 1974 to 2018
- Population is driver has slightly higher correlations with customers than households
- Both drivers are common with in the electric industry

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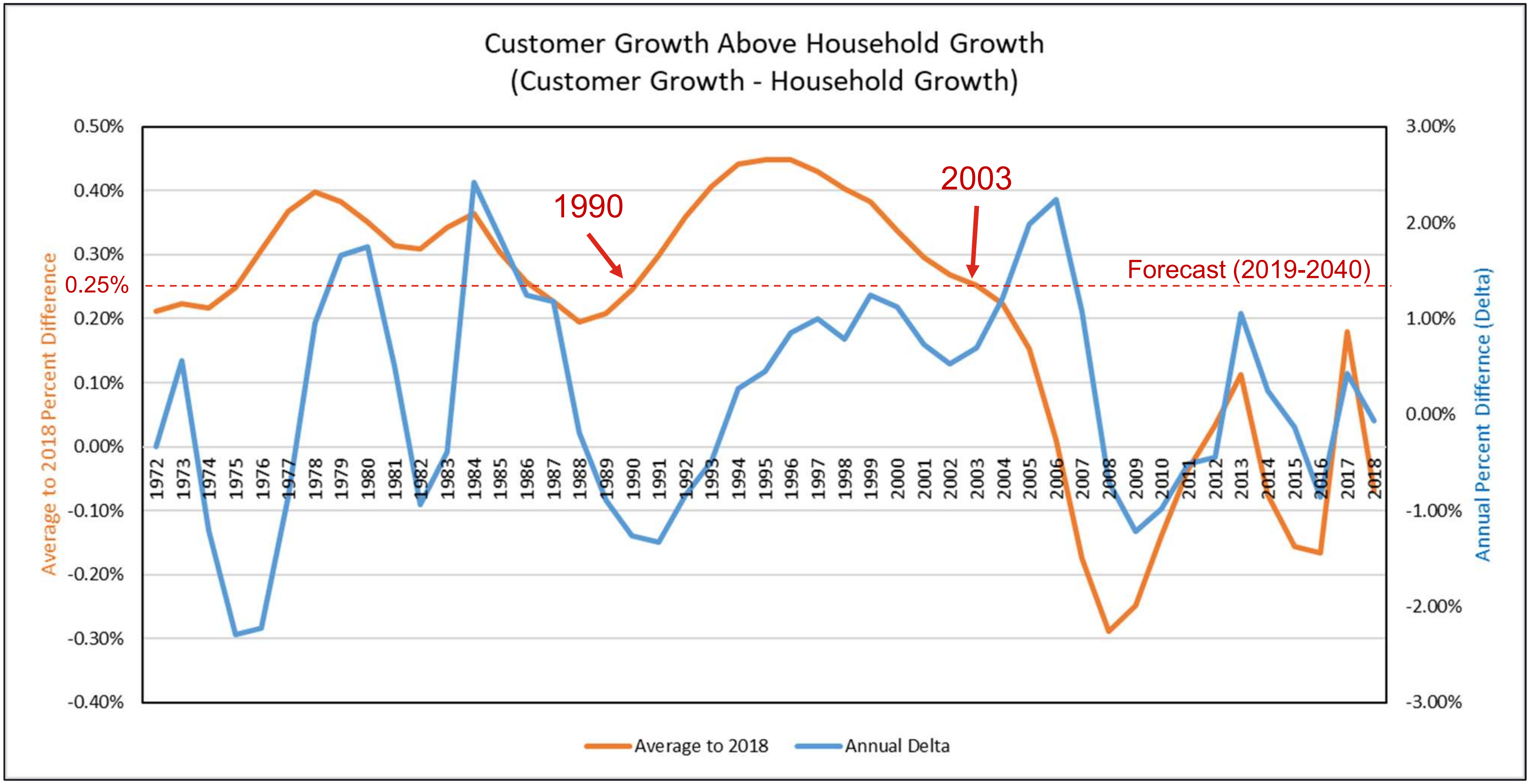
RESIDENTIAL CUSTOMERS AND HH GROWTH



- Forecast captures the long-term average
- Post recession (2010-2018) relationship is weaker (-0.03%) and less stable due to fewer years.

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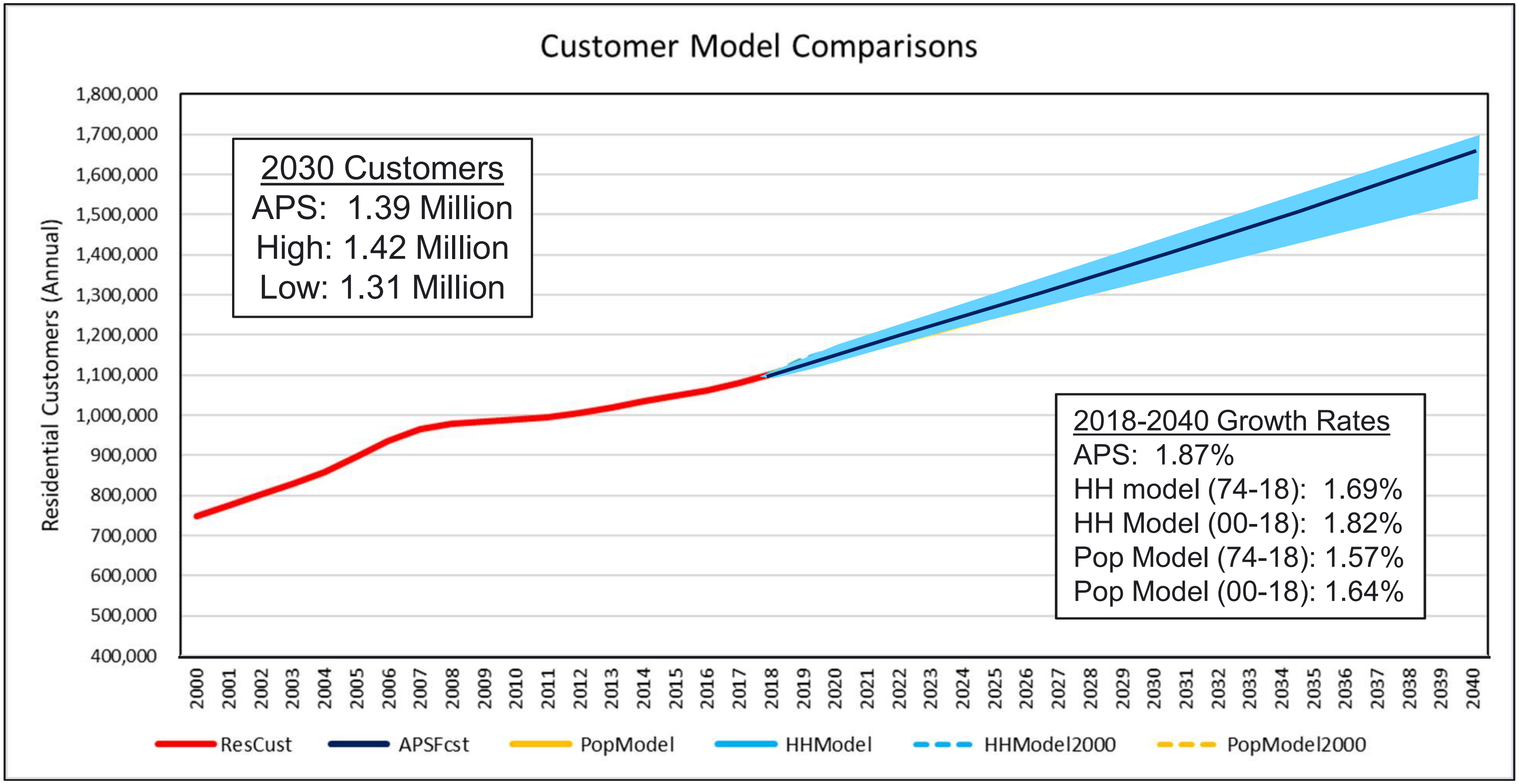
RESIDENTIAL CUSTOMER SENSITIVITY



- APS forecast is in the range of possible futures.
- Higher forecasts tend to use more historic data.
- Population drivers create stronger statistical models and lower forecast trajectories.

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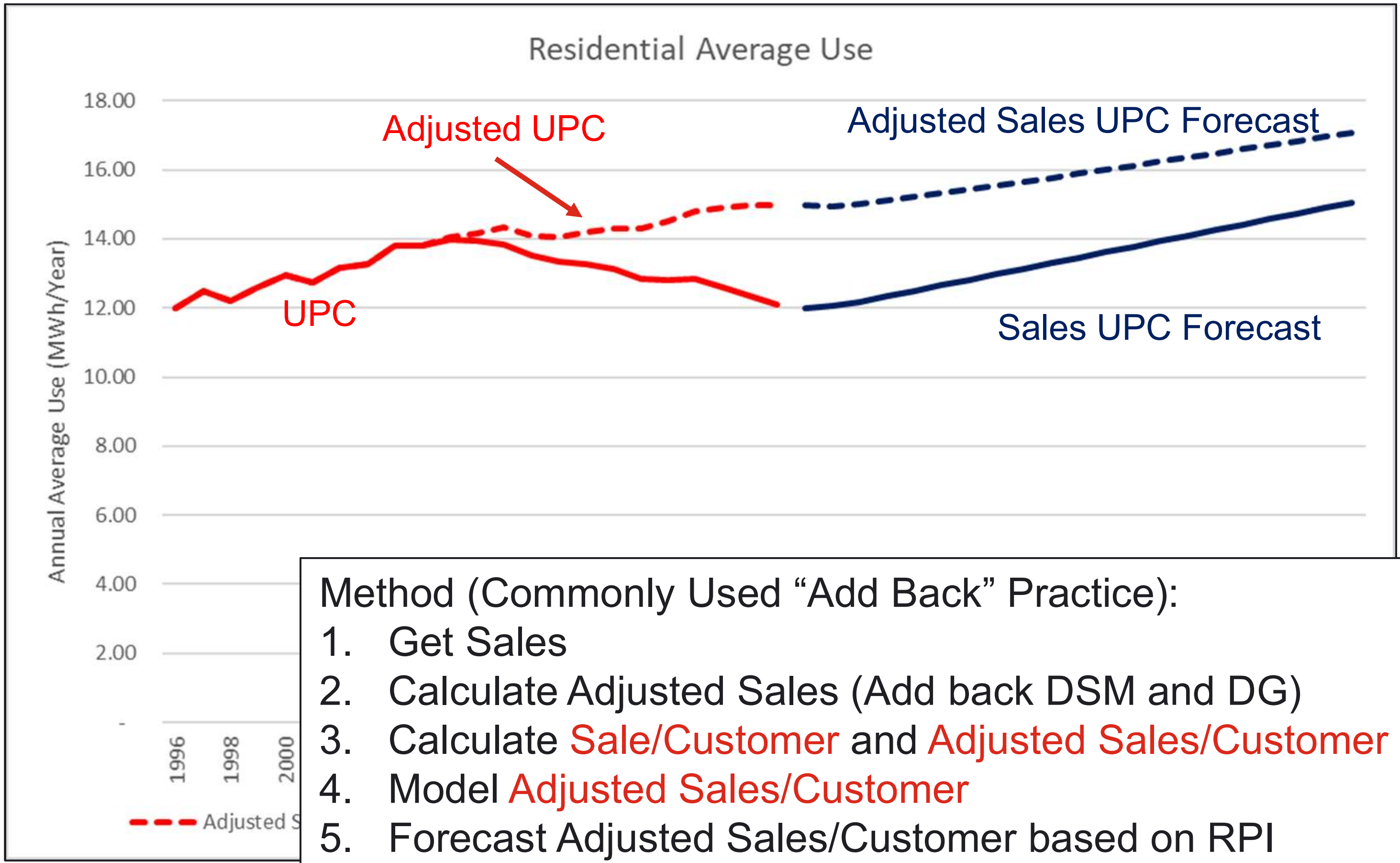
CUSTOMER FORECAST CONCLUSION

- Customer forecast is in line with expectations
- Household driver is appropriate

RESIDENTIAL AVERAGE USE MODEL

Itron

AVERAGE USE FORECAST

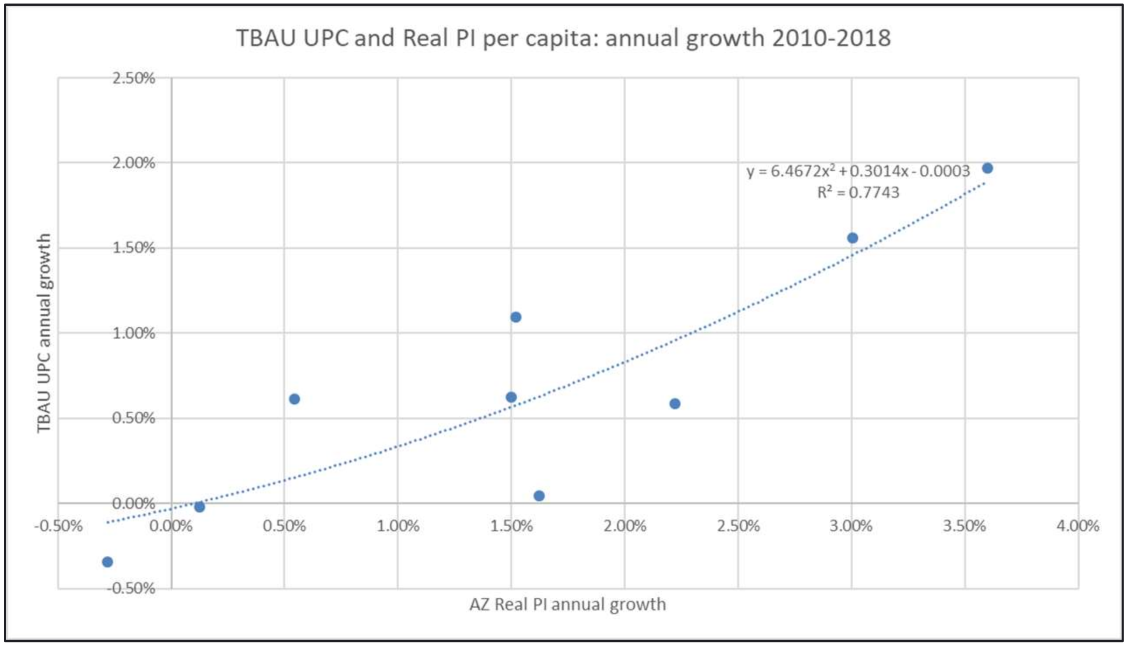


Method (Commonly Used "Add Back" Practice):

1. Get Sales
2. Calculate Adjusted Sales (Add back DSM and DG)
3. Calculate Sale/Customer and Adjusted Sales/Customer
4. Model Adjusted Sales/Customer
5. Forecast Adjusted Sales/Customer based on RPI
6. Forecast Adjusted Sales by multiplying by Customers
7. Forecast Sales by removing DSM and DG
8. Calculate Forecast Sales/Customer

STATISTICAL MODEL (UPC)

Adjusted Sales UPC GR = -0.0003 + 0.3014 RPI GR + 6.467x RPI GR^2



- Data is post-recession (2010-2018)
- Relationship is assumed quadratic
- First 6 years of forecast are manually adjusted down
- Model controls the UPC forecast

	Real Pers Inc per capita (AZ)	TBAU UPC	Adjustment
2010	-0.28%	-0.34%	
2011	1.52%	1.09%	
2012	1.50%	0.63%	
2013	0.12%	-0.02%	
2014	3.00%	1.56%	
2015	3.60%	1.97%	
2016	0.54%	0.61%	
2017	2.22%	0.59%	
2018	1.62%	0.04%	
2019	2.46%	-0.20%	1.30%
2020	2.24%	-0.03%	1.00%
2021	2.11%	0.39%	0.50%
2022	1.82%	0.68%	0.05%
2023	1.75%	0.68%	0.02%
2024	1.76%	0.69%	0.01%
2025	1.80%	0.70%	0.02%
2026	1.77%	0.70%	
2027	1.79%	0.72%	
2028	1.83%	0.74%	
2029	1.86%	0.75%	
2030	1.85%	0.75%	
2031	1.82%	0.73%	
2032	1.82%	0.73%	
2033	1.84%	0.74%	
2034	1.82%	0.73%	
2035	1.81%	0.72%	
2036	1.80%	0.72%	
2037	1.81%	0.72%	
2038	1.80%	0.72%	
2039	1.80%	0.72%	

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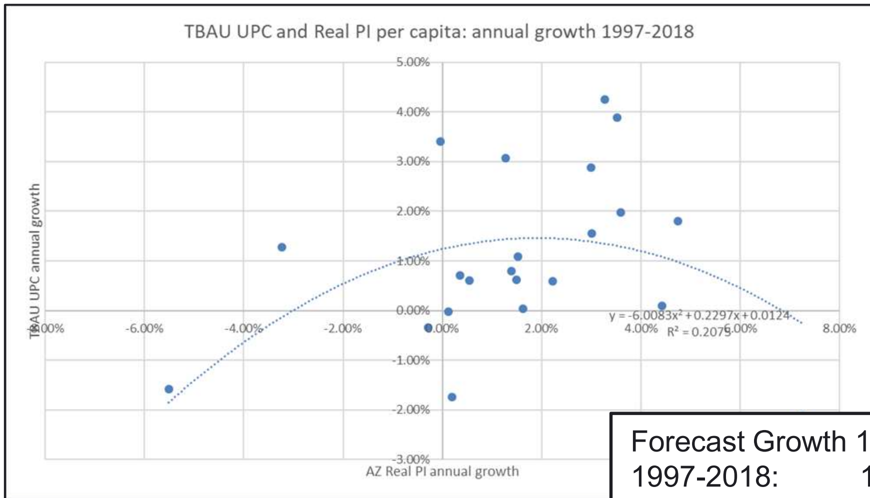
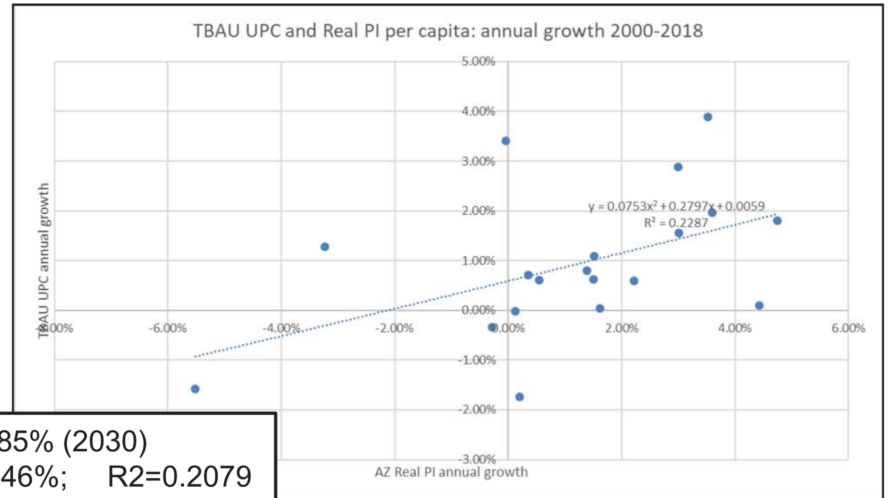
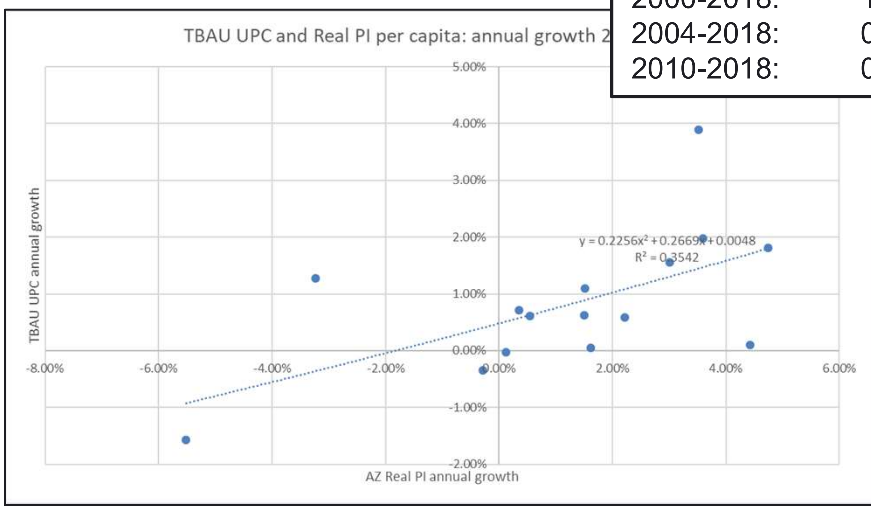
STATISTICAL MODEL ISSUE

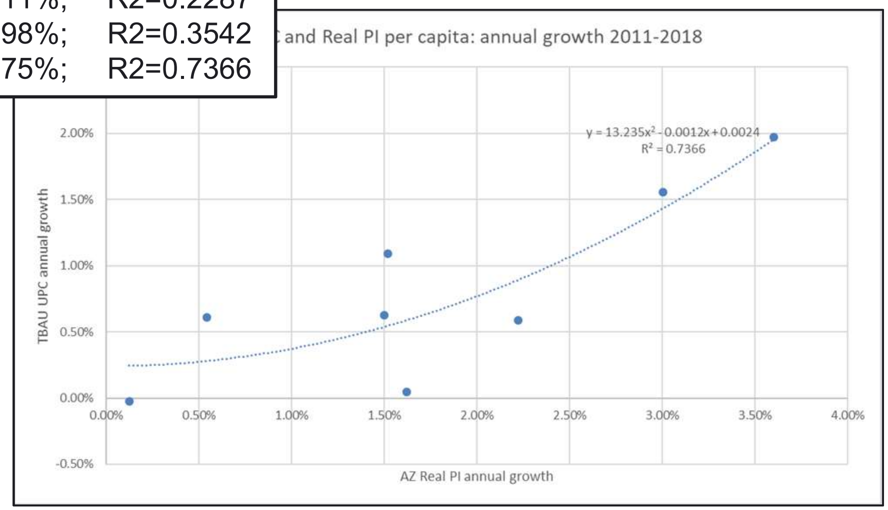




Forecast Growth 1.85% (2030)

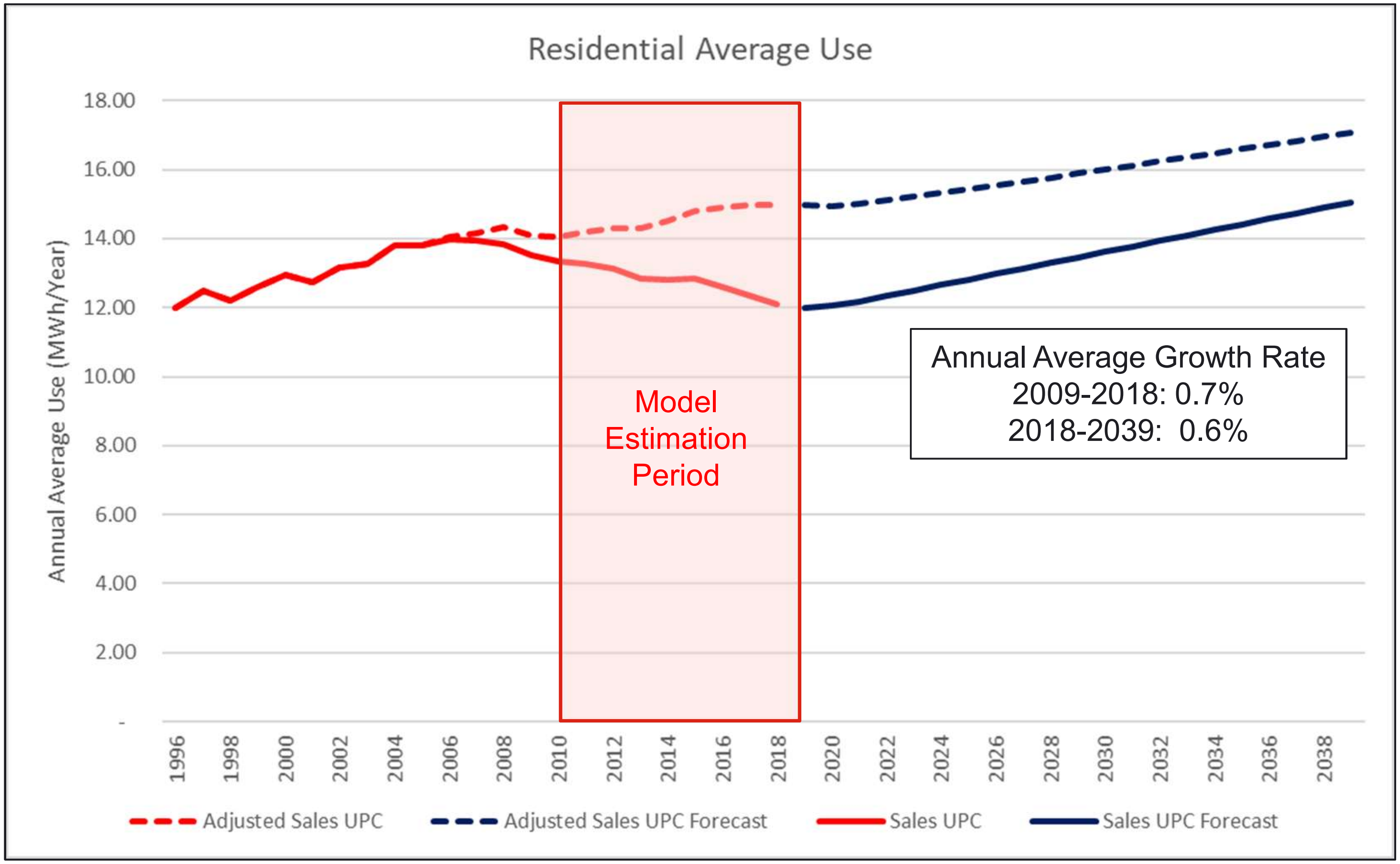
1997-2018:	1.46%;	R2=0.2079
2000-2018:	1.11%;	R2=0.2287
2004-2018:	0.98%;	R2=0.3542
2010-2018:	0.75%;	R2=0.7366





- Relationship is changing and becoming less responsive
- Relationship is not stable

STATISTICAL MODEL FORECAST



- Growth driven by real personal per capita income
- Near term growth model results are manually reduced
- Model shows signs of instability

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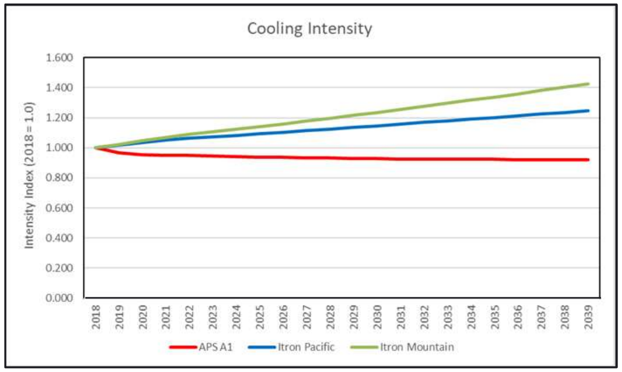
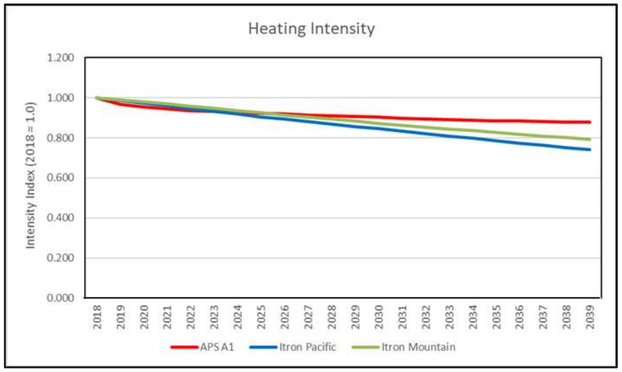
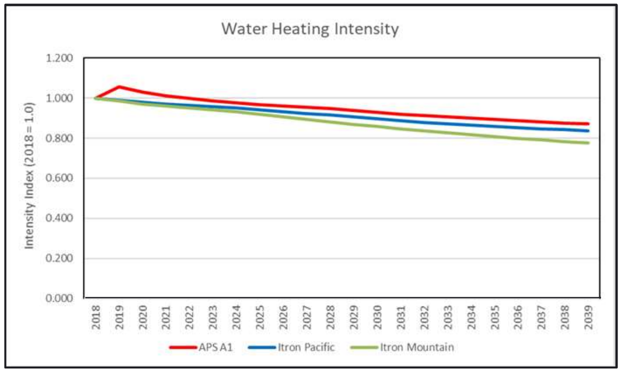
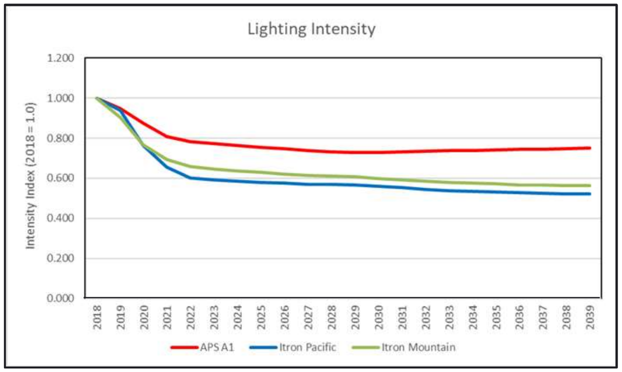
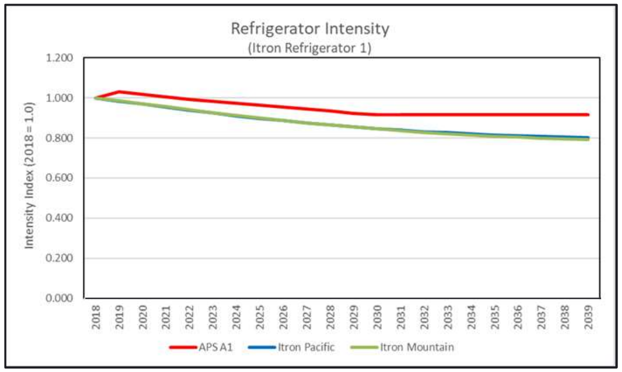
END USE FORECASTS

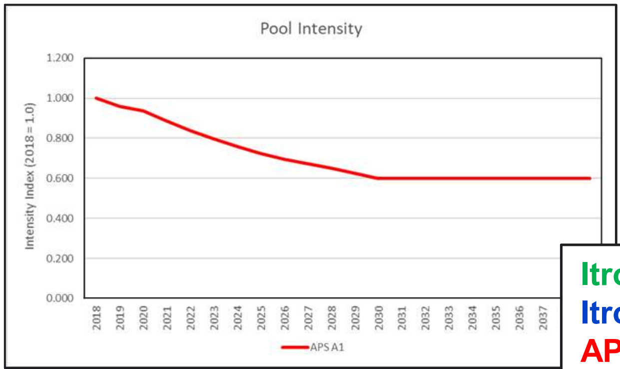












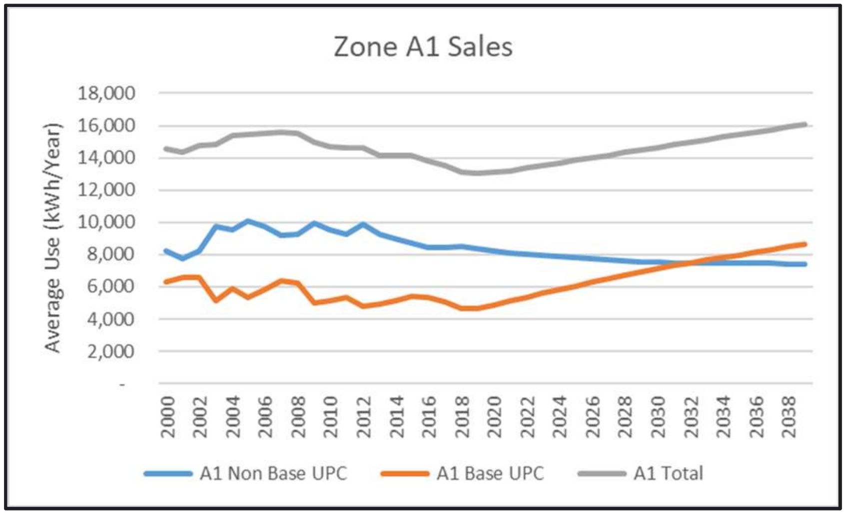
- All end uses are flat or declining.
- Consistent with Itron database
- APS cooling is flat due to 95% saturation. Itron has increasing regional cooling saturation.
- Itron does not maintain pool pump data

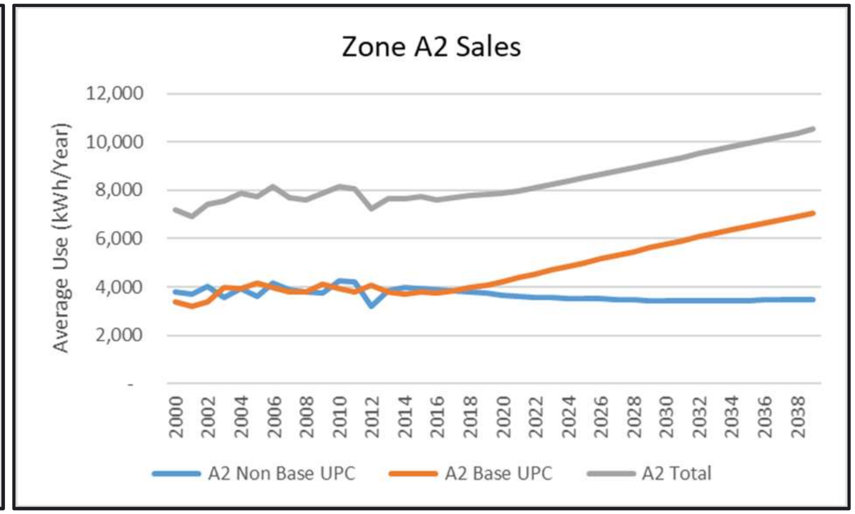
Itron Mountain
Itron Pacific
APS Forecast

Itron

MODEL RELATIONSHIPS

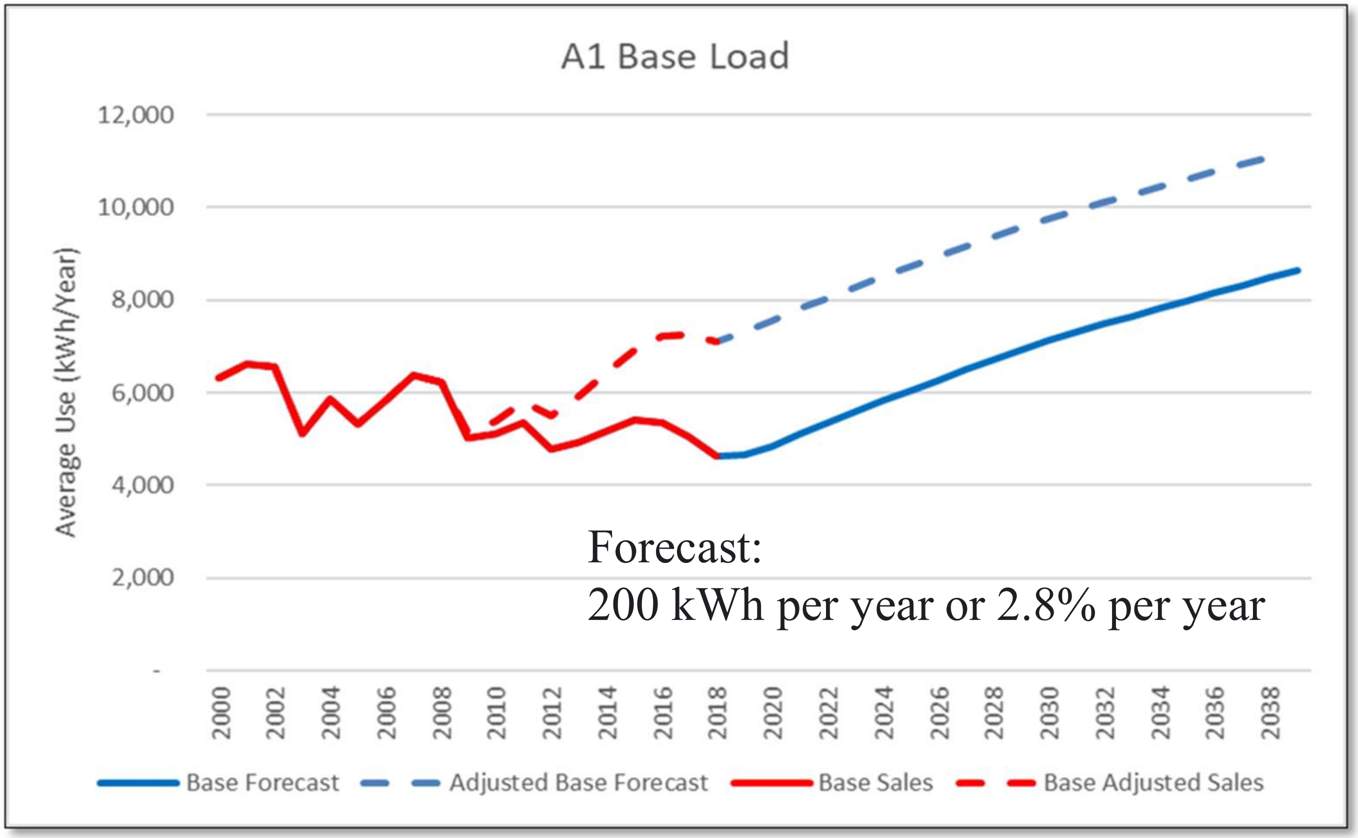
Sales UPC = Non-Base UPC + Base UPC





- Average use model (statistical) results split between Region A1 (Desert) and A2 (Mountain)
- Six end-uses: Cooling, Heating, Water Heating, Lighting, Refrigeration, Pools
- Base load end-use calculated as a residual
- History includes DSM and DG impacts

BASE USAGE



- APS base is calculated as a residual (Total – other end uses).
- Base load captures all growth.
- Historical end-use data may not be fully developed.

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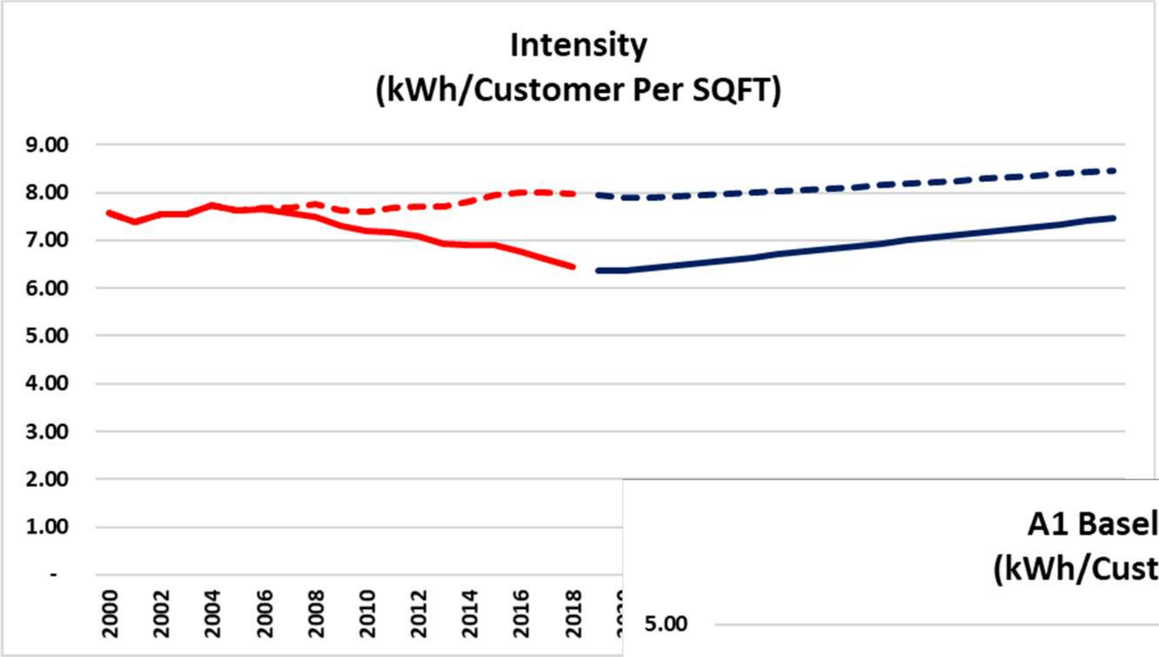
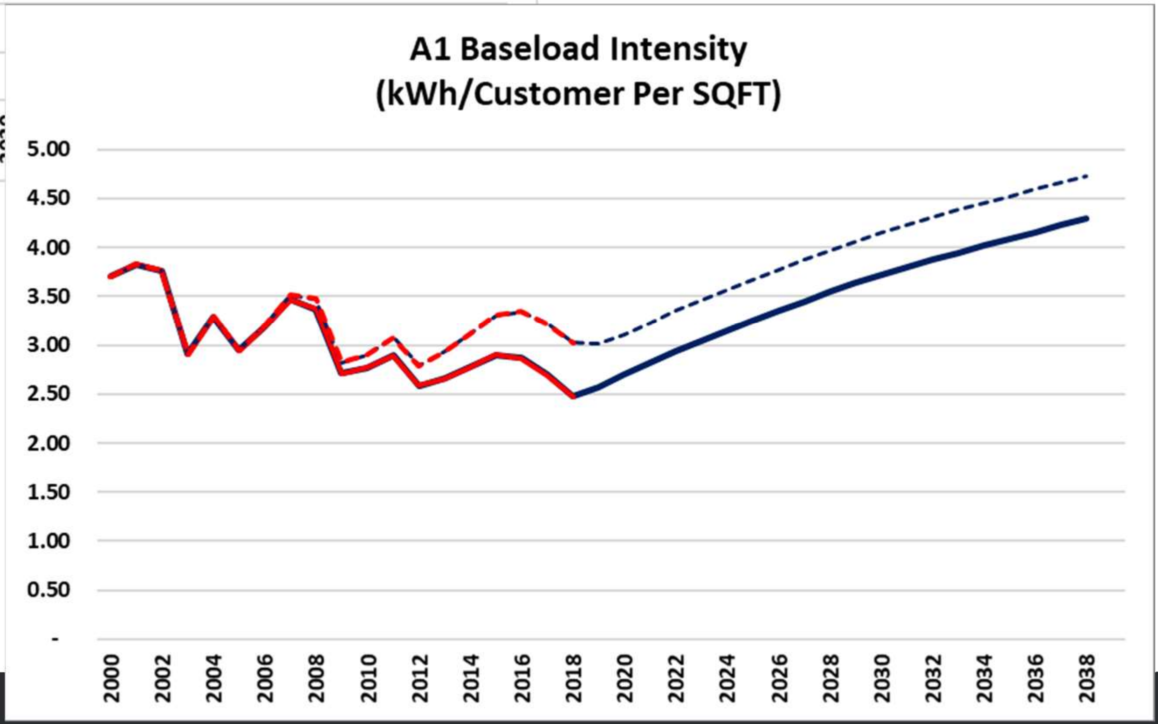
USE PER CUSTOMER INTENSITY

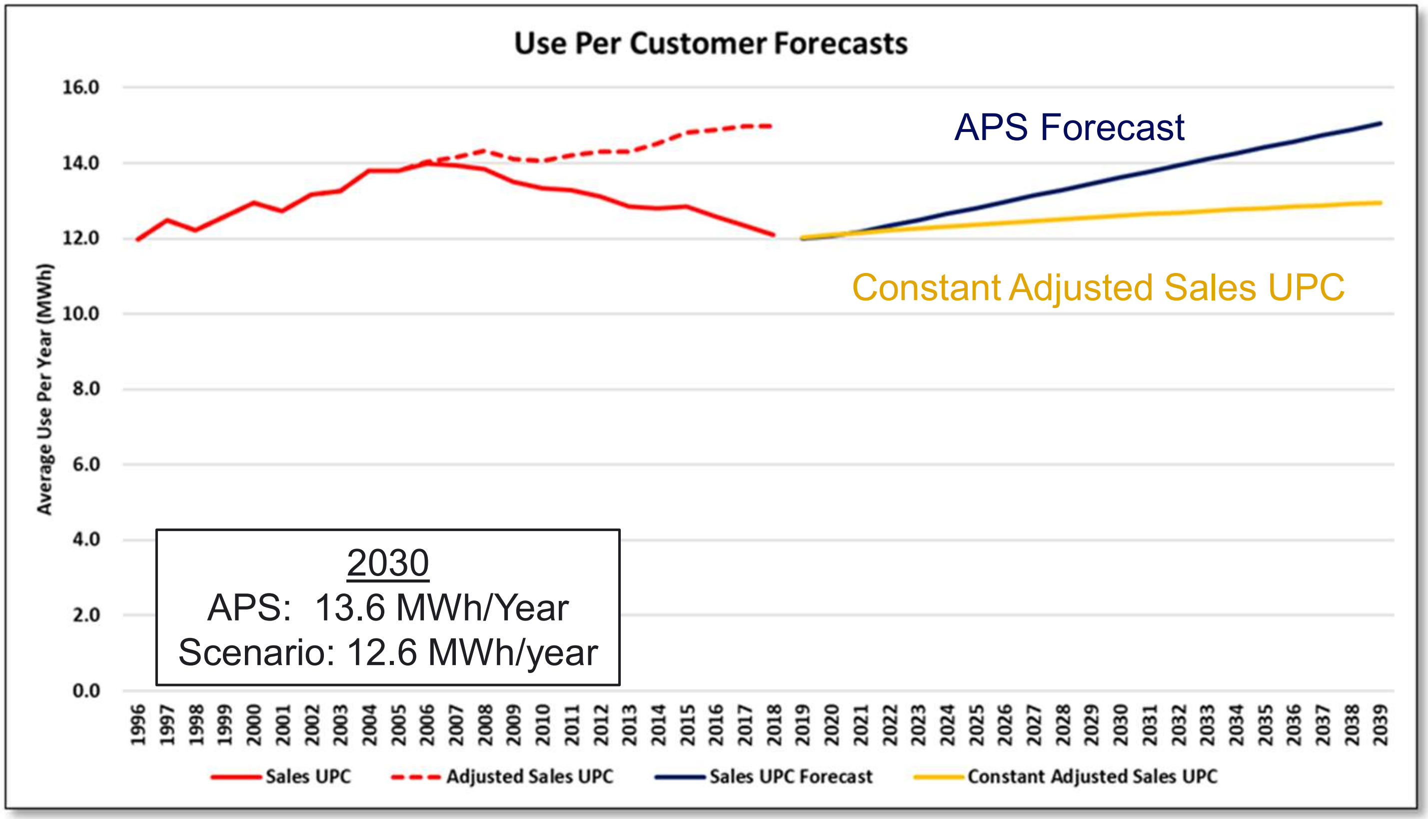


- Intensity controls forecast based on square footage.
- APS forecasts increasing average use



Itron

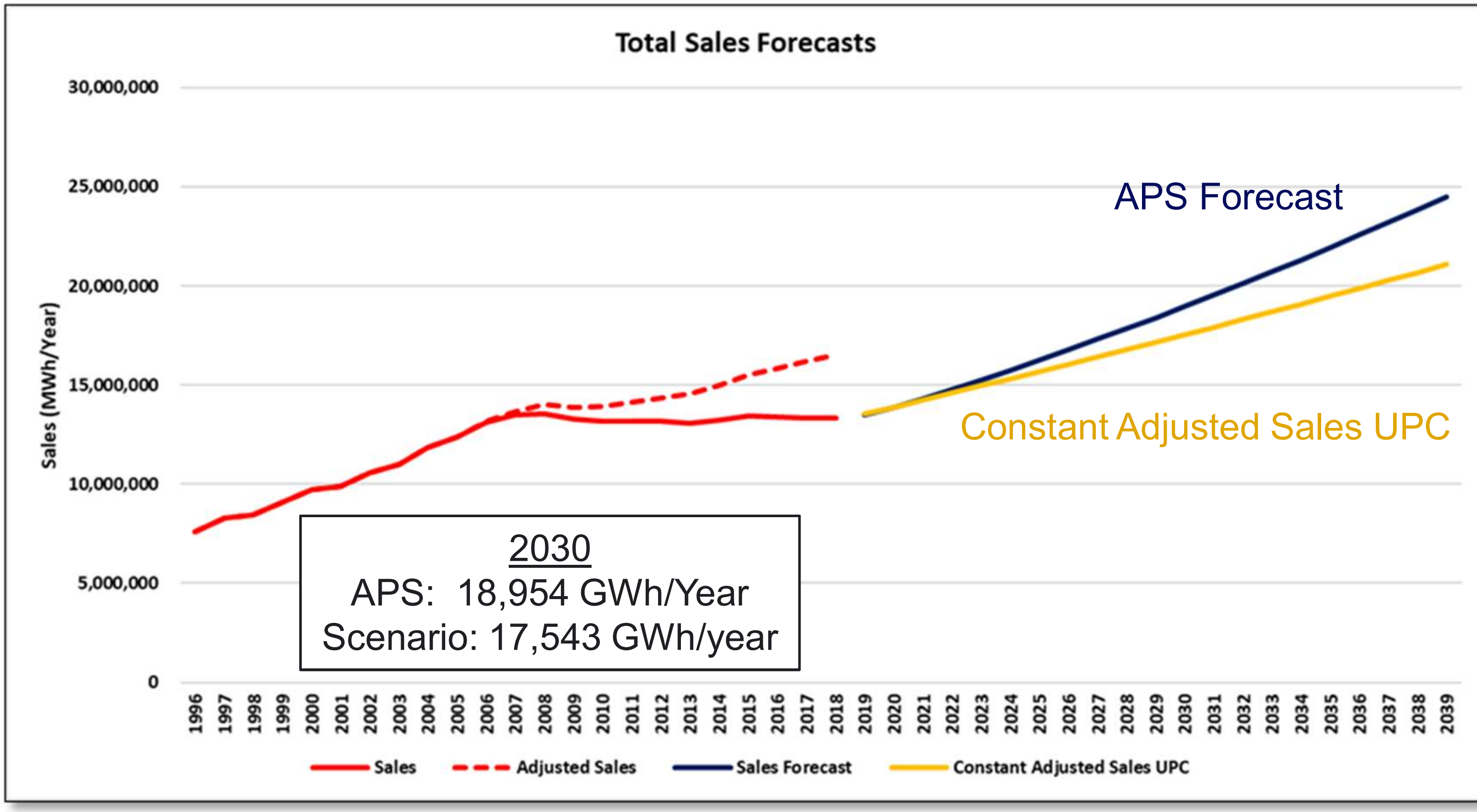
UPC SENSITIVITY



- Constant Adjusted Sales UPC shows customer growth impact.
- Difference between forecasts shows additional growth from changing UPC.

RESIDENTIAL SALES FORECAST

RESIDENTIAL SALES SENSITIVITY



- Constant Adjusted Sales UPC shows only customer growth impact.
- Difference between forecasts shows additional growth from changing UPC.

AVERAGE USE FORECAST CONCLUSION

- Add Back Method is appropriate
- Econometric model is weak
- Defined end-use forecasts in line with expectations
- Base load forecast suggests inconsistency

SUMMARY

THANK YOU

SAN DIEGO

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www.itron.com

APPENDIX F

E3
PRESENTATION TO ACC

Energy+Environmental Economics

Exploration of Energy Policy Options for Arizona

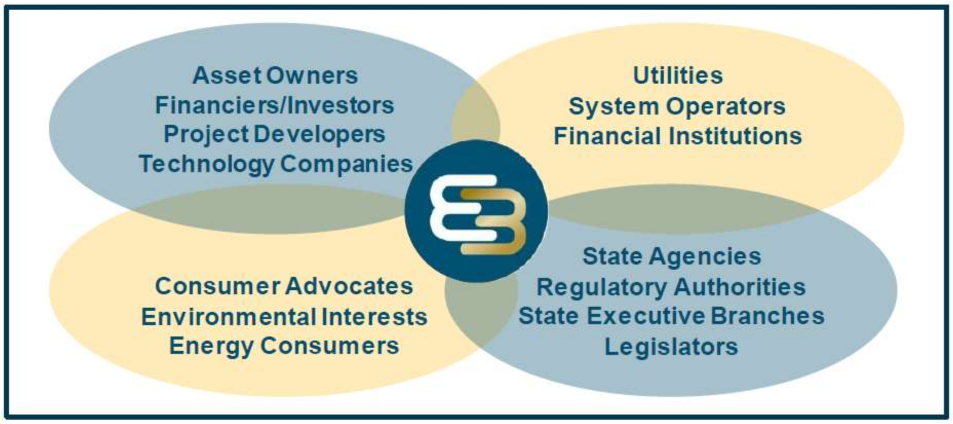
Presentation to Arizona Corporation Commission

July 31, 2019

Nick Schlag, Director

About E3

+ Founded in 1989, E3 is a leading energy consultancy with a unique 360-degree view of the industry
+ E3 operates at the nexus of energy, environment, and economics
+ Our team employs a unique combination of economic analysis, modeling acumen, and deep strategic insight to solve complex problems for a diverse client base



Key E3 resource planning studies

+ E3's resource planning studies focus on questions of how to meet aggressive carbon reduction and clean energy goals in the electric sector while maintaining reliability and managing costs

+ 2016 Power Supply Improvement Plan (HECO, 2016)
+ Pacific Northwest Low Carbon Scenario Analysis (PGP, 2017)
+ Ongoing IRP Support (CPUC, 2016-'19)
+ 2018 IRP Support (SMUD, 2018)
+ Deep Decarbonization in a High Renewables Future (CEC, 2018)
+ Upper Midwest 2019 IRP Support (Xcel, 2018-'19)
+ Resource Adequacy in the Pacific Northwest (Various utilities, 2019)
+ Resource Adequacy under Deep Decarbonization (Calpine, 2019)

Key findings common across E3 studies

1. Achieving a low-carbon grid is technically feasible and can be affordable, but eliminating carbon from the electricity sector entirely appears challenging and cost-prohibitive with current technologies

2. A technology-neutral policy focused on carbon reductions will enable utilities to meet clean energy goals more affordably than policies that establish goals for specific technologies

3. Even in a deeply decarbonized grid, natural gas resources will continue to play a crucial role in meeting reliability needs as "firm" resources, dispatchable on demand but rarely called upon

4. Openness and transparency have become foundational characteristics of successful resource planning efforts, and collaboration between utilities and stakeholders is a key step to enabling a clean energy transition

Building blocks for clean energy

+ A technology-neutral approach to establishing future goals will provide optionality as opportunities for carbon reductions evolve, enabling utilities to choose the most affordable "building blocks"

Building Block	Description
Nuclear	Maintain existing carbon-free generation
Renewables	Increase and diversify carbon-free generation
Fuel switching	Conversion from coal to gas (or other) generation
Clean imports	Utilize excess low-carbon electricity
Electrification	Electrify transportation sector and select building end uses
Energy storage	Load shifting/absorbing excess solar via energy storage
Demand management	Energy efficiency and other demand-side measures

Purpose of stakeholder engagement initiative

E3 has worked with APS to engage stakeholders in a transparent scenario analysis exercise based on detailed analytics, with the objective of enabling stakeholders to test the impacts of various resource portfolios and policies before APS files its preliminary 2019 IRP

This initiative broadly encompassed three goals:

1. Develop an Excel-based tool that balances complexities of electric system modeling with time limitations and is directionally consistent with industry standard optimization models
2. Provide stakeholders with a more active means to participate in the portfolio planning process
3. Allow stakeholders to put forth a set of scenarios to study and directionally inform APS' development of its IRP

Four groups of scenarios explore different policy options

- **Scenarios modeled generally fall into four broad categories that affect the types of investments needed in each:**
  1. **Renewable Portfolio Standard (RPS):** portfolios designed to meet a kWh production quota for renewables, expressed as a percent of retail sales (30-50% RPS by 2030)
  2. **Clean Energy Standard:** portfolios designed to meet a kWh production quota for carbon-free resources (including nuclear & clean imports), expressed as a percent of retail sales (60-80% clean by 2030)
  3. **Carbon Target:** portfolios designed to meet a specific carbon goal (40-60% reductions by 2030)
  4. **Natural Gas Prohibition:** portfolios that prohibit investment in new natural gas infrastructure to meet future reliability needs
- **Stakeholders also designed a wide range of sensitivities to test assumptions on load growth, technology costs, and other key assumptions**

Model inputs and outputs

Inputs

- Demand forecast
- Clean energy goals
- Existing resources
- Customer resources
- New resource options
- Fuel prices
- Hourly profiles
- Market prices

Model

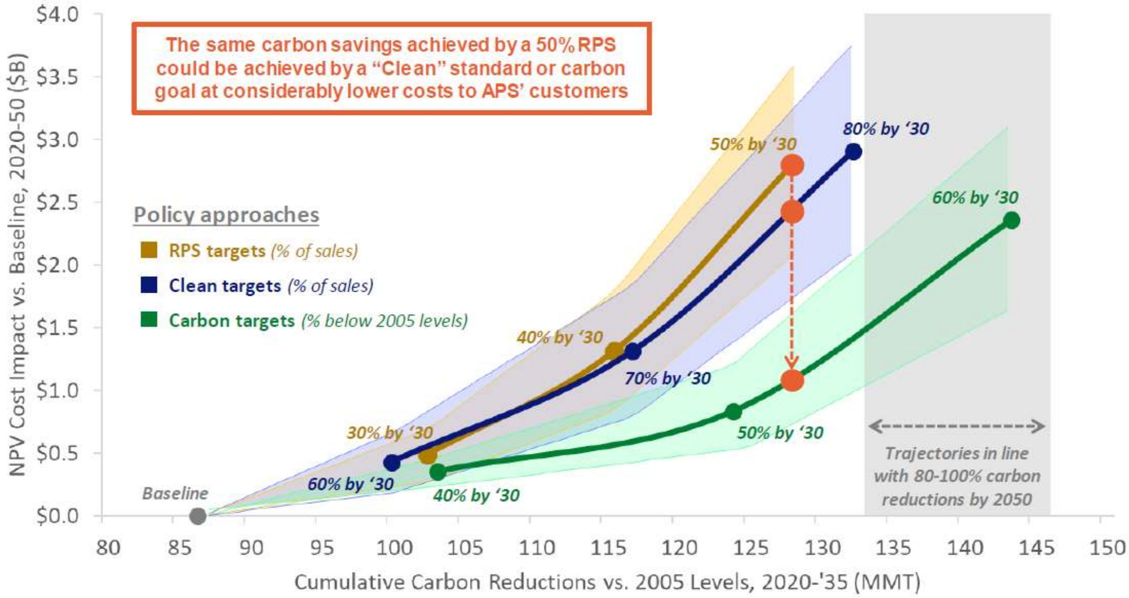
- Cost minimization
- Determine costs via hourly economic dispatch
- Identify new build resources
- Satisfy planning reserve margin
- Satisfy hourly energy needs
- Satisfy clean energy goal(s)

Outputs

- Installed capacity
- Annual generation
- Imports
- Renewable curtailment
- Carbon emissions
- Generation cost

Key focus of scenario analysis: comparing impacts of different policy & portfolio decisions on cost and carbon metrics

Estimating a range of cost & carbon impacts for APS



The expected cost impacts of a long-term prohibition on investment in new natural gas resources would result in significantly higher costs than any other scenario investigated, with an estimated NPV cost of $20-30 billion

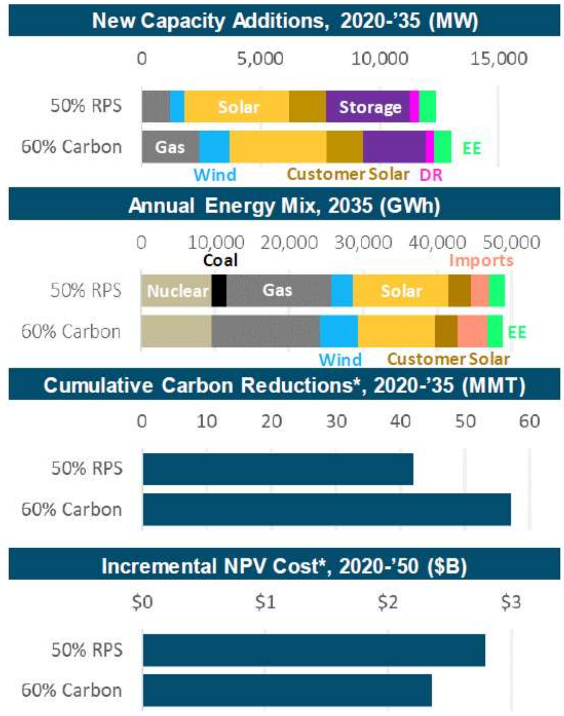
Contrasting standards: renewables & carbon

Both policies will encourage substantial investments in new clean energy resources…

…but a carbon-focused standard will lead to a more balanced & diverse generation mix…

…enabling achievement of greater carbon savings and a cleaner portfolio…

…while comparatively reducing costs for APS' customers



**Metrics measured relative to a least-cost portfolio of resources*

Key takeaways from analysis

1. APS and Arizona are experiencing continued population and load growth which could drive significant investment needs across all scenarios analyzed
2. All modeled scenarios show that significant investment in new clean resources would be needed to achieve substantial carbon reductions
3. Scenarios with broadly-defined policies to encourage clean energy and carbon reductions provide more affordable and flexible options than prescriptive targets for specific technologies that narrow utilities' choices (e.g., RPS)
4. Palo Verde is critical to meeting future clean energy goals at low costs; replacing it with other resources would considerably increase customer costs and require substantial development time
5. Scenarios with early retirement of Four Corners show significant carbon benefits, but would require large replacement investments in the next decade to maintain reliability
6. Even in deep decarbonization scenarios, firm gas resources play a crucial reliability role but operate infrequently and at low capacity factors

APPENDIX G

IRP WORKING GROUP DISCLAIMER

Disclaimer / Context Language regarding IRP Working Group and E3's Work

1. E3's model is one of many that can be used to conduct resource planning analysis and we acknowledge that other models could yield different results. The E3 model was designed to be consistent with industry standards and is sound in its technical functionality.

2. There are a wide range of inputs that can be used for any model and those that were used for this process, while not necessarily endorsed by all members of the working team, were generally considered reasonable by a majority of the group. While the process allowed for multiple inputs (e.g. different technology prices) to be evaluated, it is acknowledged that different input values would in most cases yield different results.

3. The results of the scenarios evaluated by E3 were approximated costs and carbon emission levels intended to show the relative comparison of scenarios to each other. Point data should not be considered absolute or precise.

4. There is more analysis and study underway that will inform APS's Final IRP in April 2020. This includes the following studies:

    a. Natural gas market assessment
    b. Renewable integration cost assessment
    c. Electric vehicle penetration potential (APS service territory)
    d. DSM opportunity study
    e. Third-party evaluation of APS load forecasting methodology

    APS commits to a continued public and transparent process that includes the results from these studies, policy developments/direction from the Commission, and continued input from stakeholders to inform our Final IRP.