Redhawk Power Plant

Construction and Title V Air Quality Operating Permit Significant Revision Application

Permit Number P0009401

Natural Gas-Fired Simple Cycle Combustion Turbine Expansion Project.

April 2024

Prepared for:

Arizona Public Service
400 North 5th Street
Phoenix, Arizona 85004

Prepared By:

RTP ENVIRONMENTAL ASSOCIATES INC.

AIR • WATER • SOLID WASTE CONSULTANTS

304 - A West Millbrook Road
Raleigh, NC 27609
www.rtpenv.com

Table of Contents

Chapter 1. Executive Summary. **8**

Chapter 2. Project Description. **10**

2.1 Existing Plant Description. 10
2.2 Expansion Project. 10
2.3 Purpose and Need. 10
2.4 General Electric Model LM6000PC Combustion Turbine Generators. 16
2.5 Post Combustion Air Quality Control Systems. 17
2.5.1 Selective Catalytic Reduction (SCR). 18
2.5.2 Oxidation Catalyst System. 18
2.6 Project Schedule. 19

Chapter 3. Air Emissions Analysis. **20**

3.1 Normal Operation. 20
3.2 Startup and Shutdown Emissions. 20
3.3 Total Potential Emissions for Each CT. 20
3.4 Natural Gas Piping Systems. 24
3.5 Sulfur Hexafluoride (SF_6) Insulated Electrical Equipment 25
3.6 Total Project Potential PSD and NANSR Regulated Air Emissions. 26
3.7 Potential Hazardous Air Pollutant (HAP) Emissions. 27

Chapter 4. Proposed Emission Limits. **29**

4.1 Emission Limits for Each CT, Units 3 - 10. 29
4.1.1 Emission Limits 29
4.1.2 Startup and Shutdown (SU/SD). 29
4.1.3 Operating Limits 29
4.2 Emission Limits for All Eight CTs, Units 3 – 10 Combined. 30
4.3 Initial Compliance Demonstration Requirements. 30
4.4 Monitoring and Compliance Demonstration Requirements. 30
4.5 Standards of Performance for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKK. 31
4.6 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTT. 31

Chapter 5. Applicable Requirements. **32**

5.1 Minor New Source Review (NSR) Air Permitting Requirements. 32
5.2 Major New Source Review (NSR) Air Permitting Requirements. 32
5.2.1 Prevention of Significant Deterioration of Air Quality (PSD) Program. 32
5.2.2 Nonattainment Area New Source Review (NANSR) Program. 33

5.3 Standards of Performance for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKK. 34
5.3.1 Sulfur Dioxide (SO_2) Emissions. 34
5.3.2 Nitrogen Oxides (NO_x) Emissions. 34
5.3.3 General Compliance Requirement under 40 CFR § 60.4333. 35
5.3.4 NO_x Monitoring Requirements under 40 CFR § 60.4335. 36
5.3.5 SO_2 Monitoring Requirements under 40 CFR § 60.4360 and § 60.4365. 36
5.3.6 Performance Tests under 40 CFR § 60.4400. 36
5.3.7 Reporting Requirements under 40 CFR § 60.4375. 36
5.4 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTT. 36
5.5 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTTa *(proposed)*. 37
5.6 Acid Rain Program. 38
5.7 National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines 40 CFR Part 63, Subpart YYYY. 39
5.8 40 CFR 64 – Compliance Assurance Monitoring. 40

Chapter 6. Control Technology Review Methodology. 41

6.1 Best Available Control Technology (BACT). 41
6.2 Top Down BACT Methodology. 42
6.3 Technical Feasibility. 42
6.4 Economic Feasibility. 43
6.4.1 Average Cost Effectiveness. 44
6.4.2 Incremental Cost Effectiveness. 44
6.5 Alternative to Top-Down BACT Analysis 45
6.6 Scope of the Control Technology Review. 45

Chapter 7. Nitrogen Oxides (NO_x) Control Technology Review. 48

7.1 BACT Baseline. 48
7.2 BACT Control Technology Determinations. 48
7.3 STEP 1. Identify All Available Control Technologies. 50
7.3.1 Water Injection (WI). 50
7.3.2 Dry low NO_x (DLN) Combustion. 50
7.3.3 Selective Catalytic Reduction (SCR). 50
7.3.4 Selective Non-Catalytic Reduction (SNCR). 51
7.3.5 EMx™ Catalytic Absorption/Oxidation (formerly SCONOx™). 51
7.4 STEP 2. Identify Technically Feasible Control Technologies. 52
7.5 STEP 3. Rank the Technically Feasible Technologies. 52
7.6 STEP 4. Evaluate the Most Effective Controls. 52
7.7 STEP 5. Proposed NO_x BACT/LAER Determination. 53
7.7.1 Proposed BACT /LAER for Normal Operation. 53

7.7.2 Proposed BACT/LAER Determination for Periods of Startup and Shutdown....................... 53

Chapter 8. Particulate Matter, PM_{10}, and $PM_{2.5}$ Control Technology Review....... 55

8.1 BACT Baseline. 55
8.2 BACT Control Technology Determinations. 56
8.3 STEP 1. Identify All Available Control Technologies.. 57
8.4 STEP 2. Identify Technically Feasible Control Technologies. 57
8.4.1 Low Ash / Low Sulfur Fuel.. 58
8.4.2 Post Combustion PM Control Systems. 58
8.5 STEP 3. Rank the Technically Feasible Technologies... 58
8.6 STEP 4. Evaluate the Most Effective Controls. 58
8.7 STEP 5. Proposed Particulate Matter (PM), and $PM_{2.5}$ BACT Determination. 59

Chapter 9. Greenhouse Gas (GHG) Emissions Control Technology Review...... 61

9.1 Project Operational Requirements.. 61
9.2 Potential Greenhouse Gas (GHG) Emissions.. 63
9.3 BACT Baseline. 64
9.3.1 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTT. 64
9.3.2 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTTa *(proposed)*. 64
9.4 BACT Control Technology Determinations. 65
9.5 STEP 1. Identify All Potential Control Technologies. 66
9.5.1 Use of Low Carbon Containing or Lower Emitting Primary Fuels. 67
9.5.2 Good Combustion, Operating, and Maintenance Practices...................................... 69
9.5.3 Use of Energy Efficient Processes and Technologies. 70
9.6 STEP 2. Identify Technically Feasible Control Technologies. 75
9.6.1 Lower Emitting Primary Fuels. 75
9.6.2 Energy Efficient Processes and Technologies.. 75
9.6.3 Good Combustion, Operating, and Maintenance Practices...................................... 77
9.6.4 Carbon Capture and Sequestration (CCS).. 77
9.6.5 Conclusions regarding the technically feasible control options. 79
9.7 STEP 3. Rank The Technically Feasible Control Technologies. 80
9.8 STEP 4. Evaluate the Most Effective Controls. 82
9.8.1 Natural Gas-Fired RICE Engines. 82
9.8.2 Carbon Capture and Sequestration. 83
9.9 STEP 5. Proposed Greenhouse Gas BACT Determination.. 85
9.9.1 Combustion Turbine Design. 85
9.9.2 Emission Limit. 85
9.9.3 Gas Turbine Maintenance Requirements. 87

9.9.4 Proposed GHG BACT Requirements. 87
9.10 Natural Gas Piping Systems GHG Control Technology Review. 89
9.10.1 STEP 1. Identify All Potential Control Technologies. 89
9.10.2 STEP 2. Identify Technically Feasible Control Technologies. 89
9.10.3 STEP 3. Rank the Technically Feasible Control Technologies. 90
9.10.4 STEP 4. Evaluate the Most Effective Controls. 90
9.10.5 STEP 5. Proposed GHG BACT Determination. 90
9.11 SF_6 Insulated Electrical Equipment GHG Control Technology Review. 91
9.12 STEP 1. Identify All Potential Control Technologies. 91
9.13 STEP 2. Identify Technically Feasible Control Technologies. 91
9.14 STEP 3. Rank the Technically Feasible Control Technologies. 92
9.15 STEP 4. Evaluate the Most Effective Controls. 92
9.16 STEP 5. Proposed GHG BACT Determination. 92

Chapter 10. Emission Offset Requirements. 93

10.1 Nonattainment Area Offset Requirements. 93

Chapter 11. Ambient Air Quality Assessment. 94

Chapter 12. Compliance Statement. 95

Chapter 13. Alternatives Analysis. 96

13.1 Alternative Sites. 96
13.2 Alternate Sizes. 96
13.3 Alternative Production Processes. 96
13.4 Alternative Environmental Control Techniques. 97
13.5 Emission Offsets. 97

Chapter 14. Environmental Justice. 98

14.1 Purpose. 98
14.2 EPA's Definition of Environmental Justice. 98
14.3 Overview of EPA's Environmental Justice Guidance. 98
14.3.1 Step One: Define the Study Area. 99
14.3.2 Step Two: Evaluate the Study Area Utilizing EPA's EJScreen Tool. 99
14.3.3 Step Three: Identify Potentially Adverse or Disproportionate Impacts within the Study Area. 100
14.3.4 Step Four: Ensure Meaningful Involvement of Potentially Impacted Community Members. 100
14.4 EJ Analysis Step One: Define the Study Area 101
14.5 EJ Analysis Step Two: Evaluate the Study Area Utilizing EPA's EJScreen Tool. 102
14.5.1 Demographics. 102

14.5.2 Ethnicity and Race. 103
14.5.3 Age and Sex. 105
14.5.4 Household Income and Poverty. 106
14.5.5 Limited English Proficiency. 107
14.5.6 Health. 108
14.5.7 Environmental Indicators. 111
14.5.8 Local Sensitive Receptors. 116
14.5.9 Step Three: Identify Potentially Adverse or Disproportionate Impacts within the Study Area. 116
14.5.10 Step Four: Ensure Meaningful Involvement of Potentially Impacted Community Members. 118
14.5.11 Communication and Public Outreach. 118
14.6 Conclusions. 119

Tables

TABLE 3-1. Maximum potential emission rates with controls for each LM6000PC CT during normal operation. 21
TABLE 3-2. Maximum emission rates for each LM6000PC CT during startup and shutdown. 22
TABLE 3-3. Potential emissions for each new GE LM6000PC CT based on the proposed limits in this application. 23
TABLE 3-4. Potential fugitive emissions from the natural gas piping systems. 24
TABLE 3-5. Potential fugitive SF_6 emissions from high voltage electrical equipment and the equivalent GHG emissions. 25
TABLE 3-6. Total potential PSD regulated air pollutants for the Redhawk Power Plant Natural Gas-Fired Simple Cycle Combustion Turbine Expansion Project. 26
TABLE 3-7. Potential hazardous air pollutant (HAP) emissions for each new CT and for all eight (8) CTs combined based on the proposed emission limits in this application. 28
TABLE 5-1. Total new stationary source potential emissions, the minor NSR threshold levels under Rule 241, and minor NSR applicability. All emissions are tons per year. 32
TABLE 5-2. Potential emissions for the proposed new Project and PSD or NANSR applicability. All emissions are tons per year. 33
TABLE 5-3. Total potential hazardous air pollutant emissions for the Redhawk Power Plant with the addition of the new simple cycle CT Units 3 - 10. All emissions are tons per year. 39
TABLE 7-1. NO_x LAER / BACT determinations for natural gas-fired simple cycle CTs. 49
TABLE 7-2. NO_x BACT limits for simple-cycle, natural gas-fired gas turbines. 49
TABLE 8-1. Recent PM BACT limits for simple-cycle, natural gas-fired gas turbines. 56
TABLE 8-2. Compliance emission test results for particulate matter emissions from similar combustion turbines. 60

TABLE 9-1. Potential GHG emissions for each CT based on the proposed emission limits in this application. ... 63
TABLE 9-2. Recent GHG BACT limits for natural gas-fired simple-cycle gas turbines. ... 65
TABLE 9-3. Potential CO_2 emissions for various fossil fuels. ... 67
TABLE 9-4. Summary of the technical feasibility of GHG control technologies. ... 79
TABLE 9-5. Ranking of the technically feasible GHG control technologies for the turbines. ... 80
TABLE 9-6. Performance data for the General Electric Model LM6000PC simple cycle CTs at various load and ambient air conditions. ... 81
TABLE 9-7. Expected operation and CO_2 emission rate for the GE LM6000PC CTs based on the non-degraded design heat rates. ... 86
TABLE 14-1. Summary of the environmental justice screening socioeconomic factors from EJScreen. 103
TABLE 14-2. Summary of the U.S. Census Bureau data by race for Maricopa County, the State of Arizona, and the study area around the Redhawk Power Plant. ... 104
TABLE 14-3. Summary of the U.S. Census Bureau data by age and sex for Maricopa County, the State of Arizona, and the study area around the Redhawk Power Plant. ... 105
TABLE 14-4. Summary of the U.S. Census Bureau household income data for the State of Arizona, Maricopa County, and the study area around the proposed site. ... 106
TABLE 14-5. Summary of the U.S. Census Bureau English proficiency data for Maricopa County and the study area. ... 107
TABLE 14-6. Pollution and Sources Environmental Indicators from EJScreen. ... 112

Figures

FIGURE 2-1. Total installed capacity across the planning horizon in the preferred plan. ... 11
FIGURE 2-2. Location of the Redhawk Power Plant in Arizona and Maricopa County. ... 13
FIGURE 2-3. Redhawk Power Plant aerial image and location for the CT Expansion Project. ... 14
FIGURE 2-4. Layout of the proposed new CTs on the project site. ... 15
FIGURE 2-5. Process flow diagram of a GE Model LM6000 simple cycle CT (from GE Company)... 17
FIGURE 14-1. Environmental Justice “Study Area” for the Redhawk Power Plant. ... 101
FIGURE 14-2. Year 2023 Health Outcome ranks for Arizona counties. ... 109
FIGURE 14-3. Year 2023 Health Factors ranks Arizona counties. ... 110
FIGURE 14-4. EJ Index results for the Power Plant Study Area. ... 117

Attachments

Appendix A. ... Maricopa County Air Quality Department Forms.
Appendix B. ... Air Modeling Protocol and Report.
Appendix C. ... Environmental Justice EJScreen Data for the Redhawk Expansion Project.

Chapter 1. Executive Summary.

Arizona Public Service (APS) is planning a new Natural Gas-Fired Simple Cycle Combustion Turbine Expansion Project at the existing Redhawk Power Plant (Redhawk) in Arlington, Maricopa County. Redhawk is located in an area that is classified as attainment for all criteria air pollutants except ozone. Redhawk is a major stationary source under the Title V permit program and operates under Permit Number P0009401. Redhawk is also a major stationary source under the Prevention of Significant Deterioration (PSD) and Nonattainment Area New Source Review (NANSR) construction permit programs.

The proposed Expansion Project will involve the construction and operation of eight (8) General Electric Model LM6000PC natural gas-fired simple cycle combustion turbine (CT) electric generating units and associated support equipment. Each CT will have a maximum nominal electric output of 49.6 megawatts (MW). These CTs will be equipped with state-of-the-art air quality control systems including water injection and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control and oxidation catalysts for carbon monoxide (CO) and volatile organic compound (VOC) control.

Maricopa County and the Redhawk Power Plant are classified as a marginal nonattainment area for ozone, and the regulated ozone nonattainment area pollutants are NO_x and VOC. Major modifications of a major stationary source are subject to review under the permit requirements for major modifications located in nonattainment areas in County Rule 240, Section 304. Major modifications under the NANSR program require the installation of the Lowest Achievable Emission Rate (LAER) control technology and emission offsets. LAER is the most stringent emission limitation derived from either: 1) the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or 2) the most stringent emission limitation achieved in practice by such class or category of source. Offsets are emission reductions obtained from existing sources located in the vicinity of the proposed source which offset the emissions increase from the modification and provide a net air quality benefit. The purpose for requiring offsets (or offsetting emissions decreases) is to allow an area to move towards attainment while still allowing growth.

For a marginal ozone nonattainment area, the significant threshold for both NO_x and VOC emissions is 40 tons per year. From the following table, the Project will result in significant emissions increase and a significant net emissions increase for NO_x emissions but not VOC emissions. Therefore, this Project is subject to NANSR review for NO_x emissions. This application includes a detailed LAER analysis for NO_x emissions in Chapter 7 and an emissions offset analysis in Chapter 10. Based on the LAER analysis, APS is proposing to limit NO_x emissions to the lowest emission rate for any identified similar source, equal to a NO_x emission rate of 2.3 ppmdv at 15% O_2. Note that if the area is reclassified as a serious nonattainment area, the significant threshold for both NO_x and VOC emissions is reduced to 25 tons per year, and the emission offset requirements increase from a ratio of 1.15 to 1 (i.e., a 15% reduction) to a ratio of 1.2 to 1 (i.e., a 20% reduction). APS will surrender NO_x Emission Reduction Credits (ERCs) to offset the proposed emission increases based on the nonattainment designation applicable to the area. These ERCs will result in an overall reduction in NO_x emissions in the nonattainment area and a net air quality benefit.

The PSD program in the Code of Federal Regulations, 40 CFR §52.21 and County Rule 240, Section 305 requires that a major modification of a major stationary source within an attainment area must undergo PSD review and obtain a construction permit prior to commencing construction. A major modification means any physical change or change in the method of operation of a major stationary source that would result in a significant emissions increase and a significant net emissions increase of a regulated pollutant. The following table is a summary of the potential emissions based on the proposed limits in this application. From this table, the Project will result in a significant emissions increase of NO_x, particulate matter (PM), PM_{10}, $PM_{2.5}$, and greenhouse gas (GHG) emissions. Therefore, this Project is subject to PSD review for these pollutants including the requirement to apply the Best Available Control Technology (BACT) to each pollutant.

Potential emissions for the new Project and PSD or NANSR applicability, tons per year.

Pollutant		Project Potential to Emit	PSD / NANSR Significant Threshold	OVER?
Carbon Monoxide	CO	95.0	100	**NO**
Nitrogen Oxides	NO_x	59.0	40	**YES**
Particulate Matter	PM	54.1	25	**YES**
Particulate Matter	PM_{10}	54.1	15	**YES**
Particulate Matter	$PM_{2.5}$	54.1	10	**YES**
Sulfur Dioxide	SO_2	1.9	40	**NO**
Volatile Organic Compounds	VOC	23.1	40	**NO**
Sulfuric Acid Mist	H_2SO_4	0.14	7	**NO**
Fluorides (F)	F	0.0000	3	**NO**
Lead	Pb	0.0016	0.6	**NO**
Carbon Dioxide	CO_2	366,790.2	n/a	**n/a**
Greenhouse Gases	CO_2e	367,169.0	75,000	**YES**

This application includes a detailed air quality modeling analysis as well as an additional impacts analysis as required under the PSD program. The results of this analysis demonstrate that the proposed Project and the Redhawk Power Plant will be in compliance with all applicable air quality standards for carbon monoxide (CO), nitrogen dioxide (NO_2), PM_{10}, $PM_{2.5}$, sulfur dioxide (SO_2), and lead (Pb).

This application also includes a detailed Environmental Justice (EJ) analysis of the 3-mile radius surrounding the Redhawk Power Plant. EJ is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This EJ analysis did not identify any potentially significant adverse or disproportionate impacts to the community within the study area. The study area has a low population of 217 individuals, equal to a population density of less than 8 individuals per square mile. The study area's population of all ethnic groups is lower as a percentage of the population than the County and State except for the total Hispanic population which is 35% as compared to the County at 31%, and none of the households in the study area have limited English proficiency or speak another language at home.

Chapter 2. Project Description.

2.1 Existing Plant Description.

Arizona Public Service (APS) owns and operates the Redhawk Power Plant which is located at 11600 South 363rd Avenue, Arlington, in Maricopa County. The Redhawk Power Plant operates under Title V Permit Number V99-013. Redhawk consists of two natural gas-fired combined cycle (CC) units and associated equipment and systems. Each combined cycle unit has a nominal rating of 550 megawatts (MW) of gross electrical output. Each unit has two (2) 191 MW General Electric (GE) Model 7FA CTs generators (CTGs) and one 180 MW steam turbine generator (STG). Each combined cycle unit is equipped with a heat recovery steam generator (HRSG) which provides steam to the STG common to that unit. Each HRSG is equipped with duct burners which allow for supplemental natural gas firing. Each HRSG is also equipped with a selective catalytic reduction (SCR) system for the control of nitrogen oxides (NO_x) emissions.

Figure 2-2 shows the site location of the Redhawk Power Plant in the State of Arizona and in Maricopa County. Figure 2-3 is an aerial image of the Redhawk Power Plant showing the proposed location of the Expansion Project. Figure 2-4 shows the layout of the proposed new CTs on the project site.

2.2 Expansion Project.

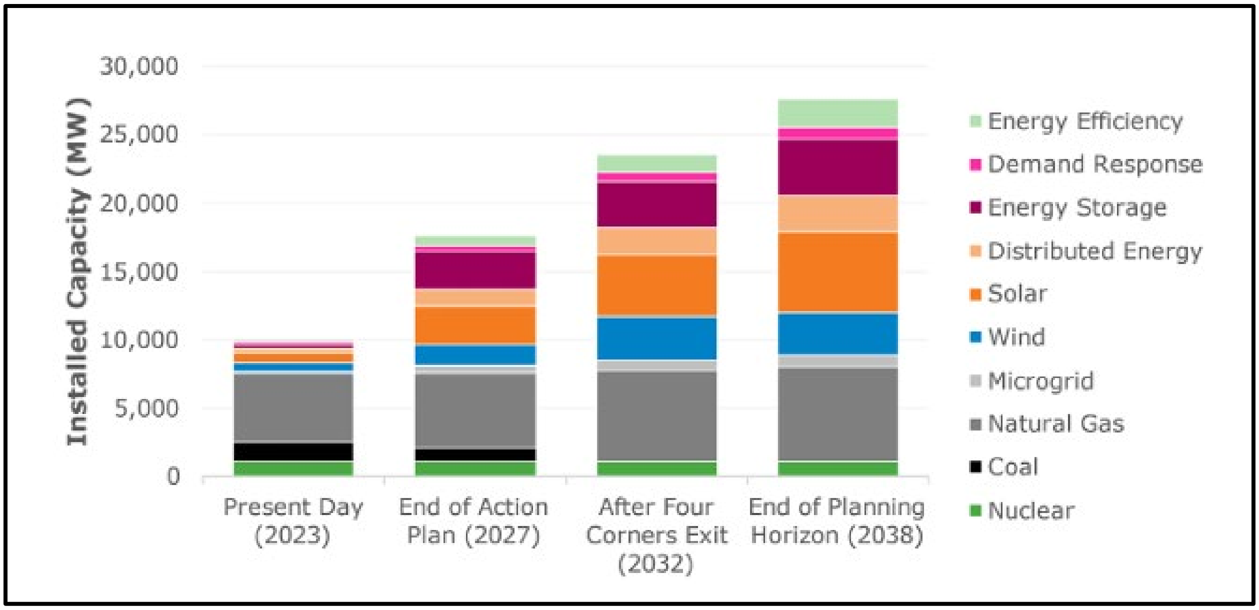
The Redhawk Power Plant Expansion Project will involve the installation of eight (8) General Electric Model LM6000PC aeroderivative simple cycle combustion turbines (CTs) with water spray power augmentation. These CT units will be identified as Units 3 - 10. Each CT will have a maximum nominal electric output of 49.6 MW and a maximum nominal natural gas fuel flow of 471mmBtu/hr (HHV). These CTs will be equipped with state-of-the-art air quality control systems including water injection and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control and oxidation catalysts for carbon monoxide (CO) and volatile organic compound (VOC) control.

2.3 Purpose and Need.

Today, Arizona is experiencing significant growth in demand for energy generation to support residential, commercial, and industrial customer load growth. At the same time, summer energy supply is tightening in the western United States, making it difficult to purchase the required energy from the energy market. These new LM6000PC simple cycle CTs, along with the solar and battery energy storage APS is adding to its resource portfolio, will help APS meet the nearly 40% load growth that is expected in the next eight years. Figure 2-1 shows the installed capacity for APS today and as projected for the next 15 years. This figure shows a wide diversity of energy resources. Having a variety of resources - including natural gas, nuclear, solar, energy storage, and customer demand response programs in APS's portfolio - makes the system more resilient to supply chain disruptions, extreme weather, and changing market conditions. Further, natural gas resources, including these new simple cycle CTs, provide critical capacity during peak system demand and support reliability when customers need it most.

Our Plan demonstrates that investment in additional renewable energy is a cost effective means to meeting customer needs. Capitalizing on opportunities for new renewable resources will require complementary investments in transmission infrastructure. Our Preferred Plan includes significant quantities of New Mexico wind, delivered to APS loads via a combination of new transmission and the repurposing of existing transmission after the exit from Four Corners. Utility-scale energy storage is an essential piece of our future resource mix and an area that we have invested heavily in, with over 2 gigawatts (GW) of planned battery additions during the Action Plan period. Storage technologies will help us use regional excess solar generation that is frequently available at low, zero, and even negative prices. We remain dedicated to a responsible adoption and integration of this nascent technology, and have committed to a maximum of 3 GW of battery energy storage through 2027. We will continually evaluate this cap as more industry experience with the technology is gained.

FIGURE 2-1. Total installed capacity across the planning horizon in the preferred plan.



The Redhawk Plant is a key component of Arizona's energy infrastructure. It currently produces 1,060 MW, enough energy to power nearly 170,000 Arizona homes. APS plans to have the additional eight units in service ahead of summer 2028 when APS's total load requirements are forecasted to be over 11,000 MW. APS needs flexible and firm generation resources like the proposed additional LM6000PC units at Redhawk to ensure sufficient reliability and resource adequacy in the face of significant customer load growth, increased reliance on renewables, extreme weather, and tightening western energy markets.

A critical component of this Project is that the proposed LM6000PC units are quick starting and fast ramping. These new CTs can be online in eight minutes and at full load in under 10 minutes - making them a critical resource to respond to fluctuations in renewable energy output throughout the day. Because these LM6000PC peaking units offer flexible, on-demand energy 24/7, they can provide much-needed energy during late afternoon and evening hours when customer demand is high, creating a strong complement to renewable energy resources such as solar. In short the new units will support reliable electrical service when APS customers need it most.

The proposed new LM6000PC CTs will also provide dynamic voltage control for the electric grid. Dynamic voltage control is the ability of a generating resource to maintain voltage levels within acceptable limits. This Project will also provide system electric inertia (kinetic energy stored during the units' operation) and frequency response (the ability of a generating resource to aid balance between generation and load on the grid) necessary for electric system stability. Batteries and renewable energy systems such as wind and solar cannot provide this necessary grid support. These attributes of the proposed CTs are critical when the electric supply resource portfolio includes more and more intermittent, renewable resources such as wind and solar.

FIGURE 2-2. Location of the Redhawk Power Plant in Arizona and Maricopa County.

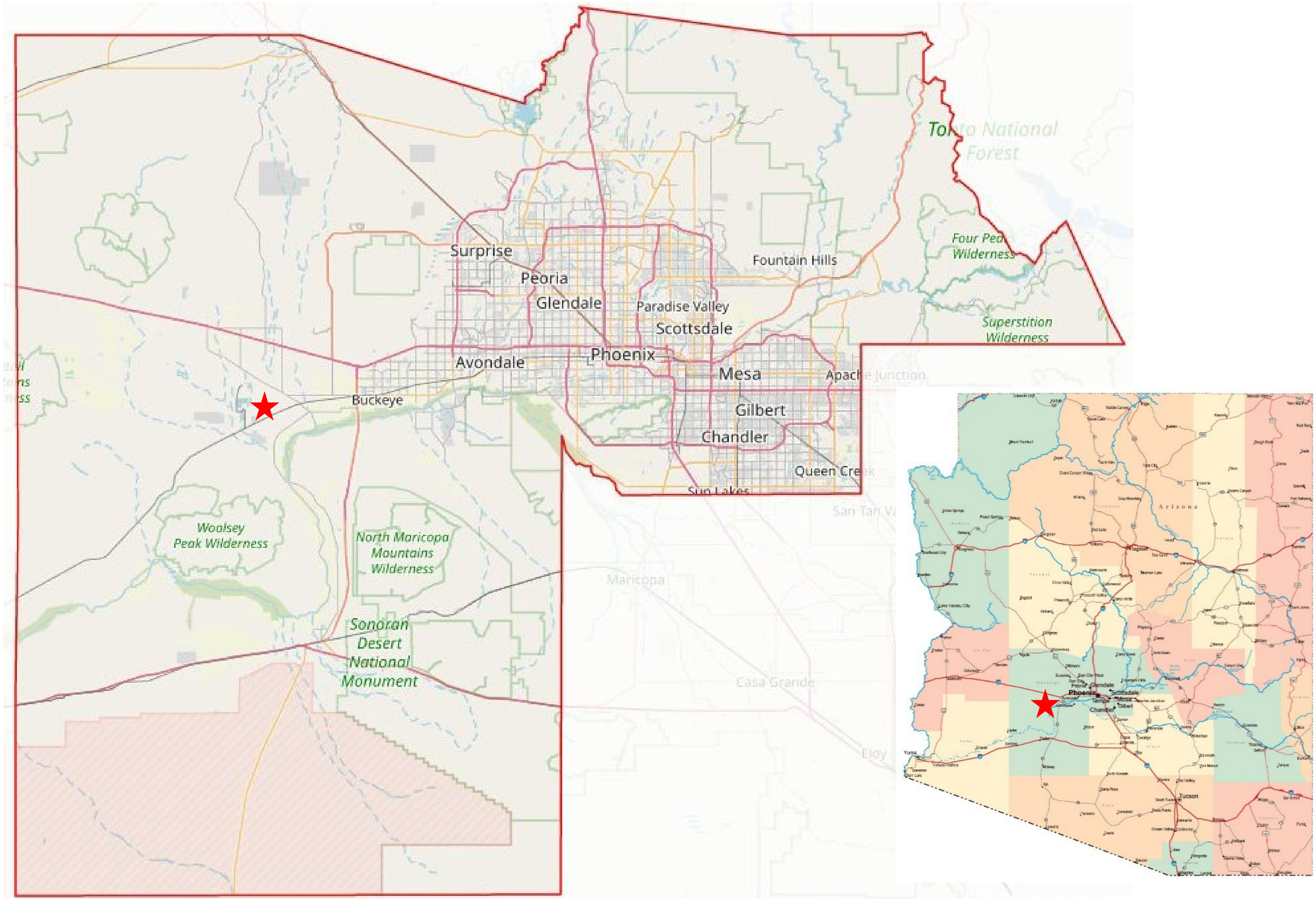
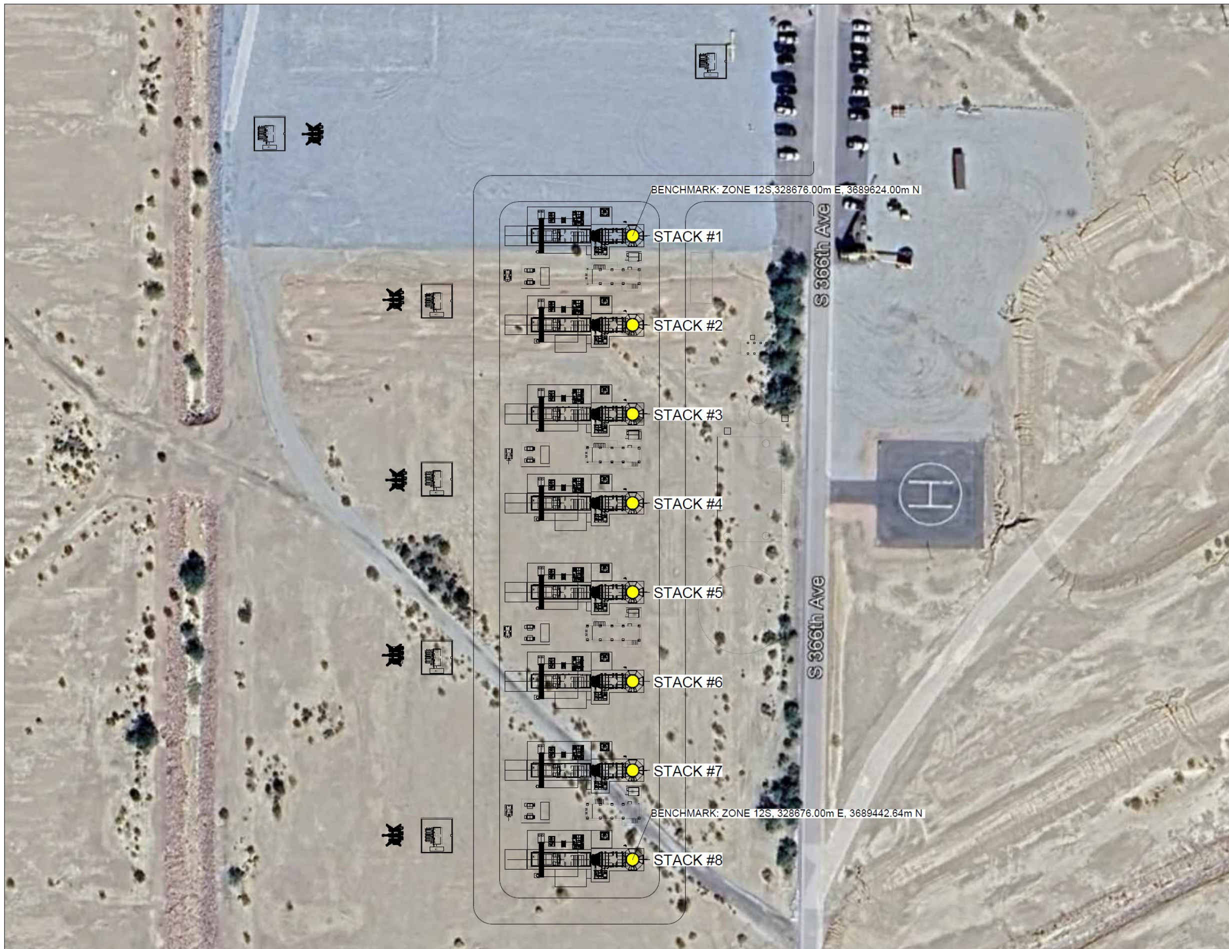


FIGURE 2-3. Redhawk Power Plant aerial image and location for the CT Expansion Project.

FIGURE 2-4. Layout of the proposed new CTs on the project site.



STACK COORDINATES			
LOCATION	ZONE	EASTING	NORTHING
STACK #1	12S	328676.00m E	3689624.00m N
STACK #2	12S	328676.00m E	3689598.09m N
STACK #3	12S	328676.00m E	3689572.18m N
STACK #4	12S	328676.00m E	3689546.27m N
STACK #5	12S	328676.00m E	3689520.36m N
STACK #6	12S	328676.00m E	3689494.46m N
STACK #7	12S	328676.00m E	3689468.55m N
STACK #8	12S	328676.00m E	3689442.64m N

LEGEND

● STACK LOCATIONS

0 50' 100'
SCALE: 1"=50'

REV	NCR/ECRN#	REV DESCRIPTION	DRAFTER	ENGINEER	QA/QC	PROJ. ENGINEER	REV DATE
-	-	ISSUED FOR INFORMATION	H. RUSSELL	-	-	J.VALENZUELA	03/01/2024

REVISION HISTORY

PROENERGY
2001 ProEnergy Blvd | Sedalia, Missouri 65301
660.829.5100 phone | 660.829.1160 fax
www.proenergyservices.com

TITLE
REDHAWK
STACK COORDINATE LOCATIONS
8xLM6000

DRAFTER H. RUSSELL | ENGINEER - | QA/QC - | PROJ. ENGINEER J. VALENZUELA
PROJECT NAME REDHAWK | CREATE DATE 02/23/2024 | REV -
SIZE D | DWG. NO. SKE-GA-001 | SHEET NO. 1 of 1

2.4 General Electric Model LM6000PC Combustion Turbine Generators.

The General Electric (GE) Model LM6000PC simple cycle CTs or gas turbines are aeroderivative CTs coupled to an electric generator to produce electric power. A CT is an internal combustion system which uses air as a working fluid to produce mechanical power and consists of an air inlet system, a compressor section, a combustion section, and a power section. The compressor section includes an air filter, noise silencer, and a multistage axial compressor.

During operation, ambient air is drawn into the compressor section. The air is compressed and heated by the adiabatic compression of the inlet gas and also by the combustion of fuel in the combustor section. The expansion of the high pressure, high temperature gas expands through the turbine blades which rotate the turbine shaft in the power section of the turbine, and the rotating shaft powers an electric generator. The LM6000PC CTs are aeroderivative units based on turbine designs in the aviation industry. This aeroderivative design is capable of fast starts and fast ramping to full electric output capacity. Figure 2-5 is a process flow diagram for the LM6000 CTs. These CTs will be equipped with inlet air filters which remove dust and particulate matter from the inlet air. During hot weather, the filtered air may also be cooled utilizing water spray fogging systems. During cold weather, the filtered air may be mixed with warm air from the turbine compartment which is part of the anti-icing system. The filtered air is drawn into the compressor section of the gas turbine where the air is compressed. The air temperature rises adiabatically along with the increase in pressure. These CTs will also be equipped with Water Spray Power Augmentation (WSPA). This water flow increases the mass flow of gases through the turbines and results in higher electric power output.

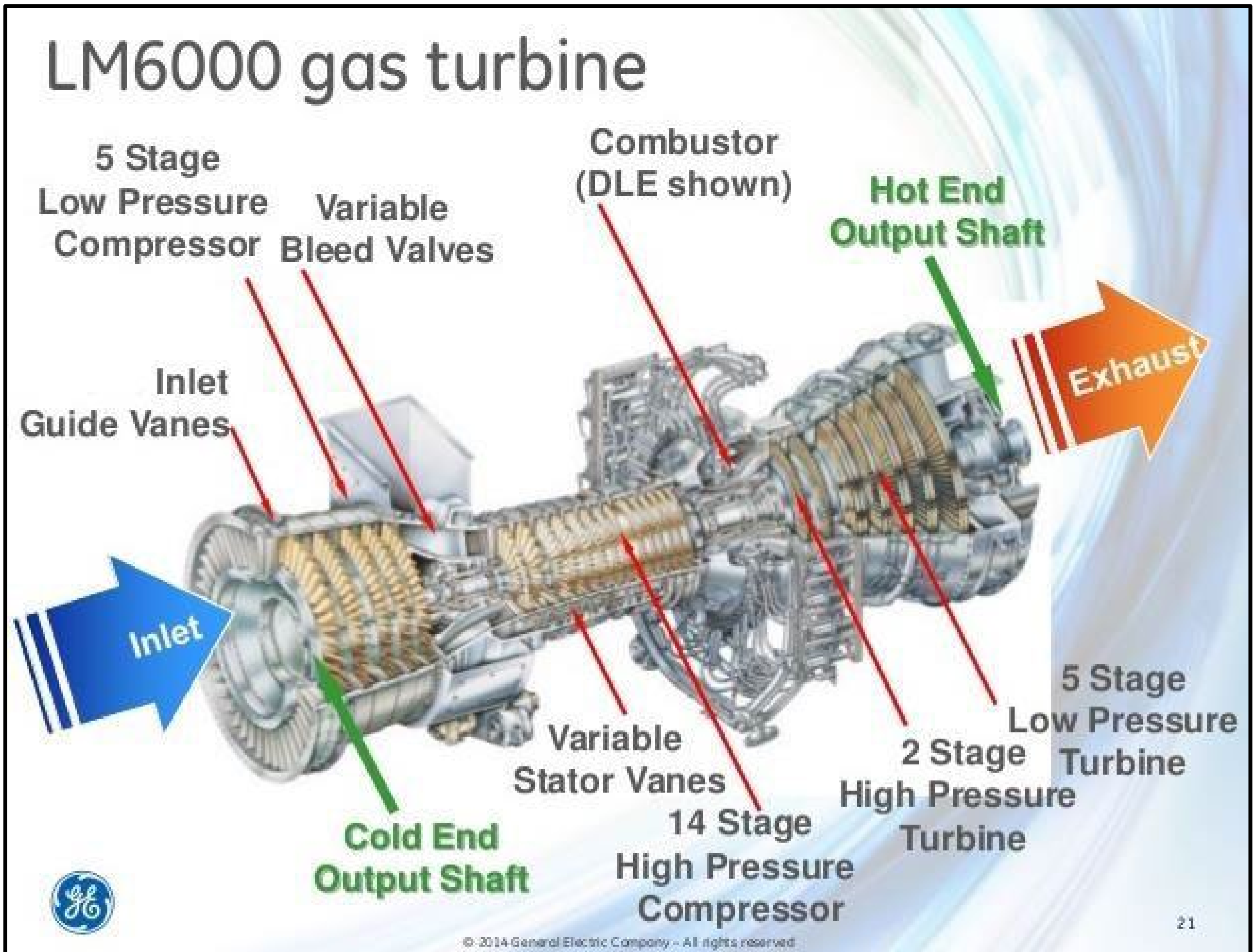
The hot, compressed air flows to the combustion section of the CT where high-pressure natural gas is injected into the turbine and the air/fuel mixture is ignited. Water is also injected into the combustion section of the CT which reduces flame temperatures and reduces thermal NO_x formation. The combustion gases pass through the power or expansion section of the turbine which consists of blades attached to a rotating shaft, and fixed blades or "buckets". The expanding gases cause the blades and shaft to rotate. The power section of the turbine extracts energy from the hot compressed gases which cools and reduces the pressure of the exhaust gases. The power section of the turbine produces the power to drive the electric generator.

Each CT and generator will be enclosed in a metal acoustical enclosure which will also contain accessory equipment. The CTs will be equipped with the following equipment:

- Inlet air filters
- Inlet air fogging
- Metal acoustical enclosure to reduce sound emissions
- Air cooled (fin fan) lube oil coolers for the turbine and generator
- Annular standard combustor combustion system
- Water injection system for NO_x control
- Compressor wash system to clean compressor blades

- Fire detection and protection system
- Hydraulic starting system
- Compressor variable bleed valve vent to prevent compressor surge in off-design operation

FIGURE 2-5. Process flow diagram of a GE Model LM6000 simple cycle CT (from GE Company).



NOTE: This diagram shows dry low NOx (DLE) combustors. The proposed CTs will have SAC combustors with water injection.

2.5 Post Combustion Air Quality Control Systems.

The combustion gases exit each CT at approximately 760 to 926 ºF. The exhaust gases will then pass through two post combustion air quality control systems, including oxidation catalysts for the control of carbon monoxide (CO) and volatile organic compounds (VOC), and selective catalytic reduction (SCR) systems for the control of nitrogen oxides (NO_x) emissions. The units will utilize a high temperature catalyst formulation which has a continuous operating temperature of approximately 900 °F.

2.5.1 Selective Catalytic Reduction (SCR).

Selective Catalytic Reduction (SCR) is a post combustion flue gas treatment technique for the reduction of NO_x emissions which uses an aqueous ammonia (NH_3) or aqueous urea ($CO(NH_2)_2$) injection system and a catalytic reactor. The injection grid disperses urea or ammonia in the flue gas upstream of the catalyst. At the SCR operating temperature, urea decomposes to ammonia. Ammonia reacts with NO_x in the presence of the catalyst to form nitrogen (N_2) and water (H_2O) according to the following reaction equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

Catalysts are substances which evoke chemical reactions that would otherwise not take place, and act by providing a reaction mechanism that has a lower activation energy than the uncatalyzed mechanism. For SCR, the catalyst is usually a noble metal, a base metal (titanium or vanadium) oxide, or a zeolite-based material. Noble metal catalysts are not typically used in SCR because of their very high cost.

To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to critical temperature considerations, the NH_3 or urea injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x. Excessive ammonia injection will result in NH_3 emissions, called ammonia slip. SCR has the capability to make substantial reductions in NO_x emissions from boilers, CTs, and engines. For these CTs, the use of SCR is expected to reduce NO_x emissions by approximately 90%.

2.5.2 Oxidation Catalyst System.

For natural gas-fired gas turbines applications, CO and VOC emissions may be controlled using oxidation catalysts installed as a post combustion control system. A typical oxidation catalyst is a rhodium or platinum (noble metal) catalyst on an alumina support material. The catalyst is typically installed in a reactor with flue gas inlet and outlet distribution plates. CO and VOC react with oxygen (O_2) in the presence of the catalyst to form carbon dioxide (CO_2) and water (H_2O) according to the following general equations:

$$2CO + O_2 \rightarrow 2CO_2$$
$$2C_nH_{2n+2} + (3n + 1)O_2 \rightarrow 2nCO_2 + (2n+2)H_2O$$

Oxidation catalysts have the potential to achieve a 90% reduction in uncontrolled CO emissions at steady state operation. VOC reduction capabilities are expected to be less.

2.6 Project Schedule.

The following is the expected schedule for the Redhawk Power Plant Natural Gas-Fired Simple Cycle Combustion Turbine Expansion Project.

Submit Air Quality Operating Permit Significant Revision Application	April 2024
Begin Detailed Engineering	January 2, 2025
Permit Issue Date	August 1, 2025
Contractor Mobilization	Feb 1, 2026
Major Foundations Complete	October 1, 2026
Major Equipment rough set on foundations	Feb 1, 2027
Begin Commissioning	August 1, 2027
Facility Commercial Operation	March 1, 2028

Chapter 3. Air Emissions Analysis.

Potential emissions for these new LM6000PC CTs are based on the use of water injection and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control and oxidation catalysts for CO and VOC control. This emissions analysis is based on a maximum design nominal fuel flow of 471 mmBtu/hr (HHV). In addition, the emissions in this analysis are based on the proposed Best Available Control technology (BACT) and Lowest Achievable Emission Rate (LAER) technology for NO_x emissions, the proposed BACT emission limits for particulate matter (PM), PM_{10}, $PM_{2.5}$, and greenhouse gas (GHG) emissions, and the proposed emissions and operational limits as detailed in Chapter 4 of this application.

3.1 Normal Operation.

The maximum PSD regulated pollutant emission rates for each LM6000PC CT during normal operation and with controls are summarized in Table 3-1.

3.2 Startup and Shutdown Emissions.

The CT air pollution control systems including the SCR and oxidation catalyst systems are not operational during periods of startup and shutdown (SU/SD) because the exhaust gas temperatures are too low for these systems to function as designed. In addition, water injection used to control NO_x emissions cannot be used during startup because injecting water too soon can impact the CT flame stability and combustion dynamics, and it may also increase CO emissions. As a result, CO, NO_x, and VOC emissions may be elevated during periods of startup and shutdown.

Table 3-2 is a summary of the startup and shutdown duration, the expected fuel consumption, expressed as mmBtu, and the PSD regulated air pollutant emissions. ***Note that the startup and shutdown durations, heat input, and emissions, expressed in pounds per event, are the maximum expected values.*** Under normal conditions, these CTs can startup in approximately 8 - 10 minutes which will result in lower heat input and emission rates. Furthermore, the emission rates for PM, PM_{10}, and $PM_{2.5}$ emissions, as well as SO_2, sulfuric acid mist, lead (Pb), CO_2, and GHG emissions, expressed in pounds per million Btu of heat input (lb/mmBtu), are NOT elevated during periods of startup and shutdown. Therefore, the highest mass emission rate for these pollutants, expressed in pounds per hour, occurs during normal operation at 100% of the rated capacity of the CTs. Further, the total mass emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, sulfuric acid mist, lead (Pb), CO_2, and GHG emissions, expressed in tons per year, can be accumulated based only on heat input and the respective pollutant emission rate, expressed in lb/mmBtu.

3.3 Total Potential Emissions for Each CT.

Table 3-3 is a summary of the total potential emissions for each CT based on the proposed emission limits and operational limits detailed in Chapter 4 of this application.

TABLE 3-1. Maximum potential emission rates with controls for each LM6000PC CT during normal operation.

Pollutant		Heat Input	Emission Rate		
		mmBtu/hr	lb/mmBtu	ppm @ 15% O_2	lb/hr
Carbon Monoxide	CO	471	0.00894	4.0	4.21
Nitrogen Oxides	NO_x	471	0.00848	2.3	3.99
Particulate Matter	PM	471	0.015		7.00
Particulate Matter	PM_{10}	471	0.015		7.00
Particulate Matter	$PM_{2.5}$	471	0.015		7.00
Sulfur Dioxide	SO_2	471	0.0006		0.28
Vol. Org. Compounds	VOC	471	0.0055		2.60
Sulfuric Acid Mist	H_2SO_4	471	0.000046		0.022
Fluorides (F)	F	471	0.0000		0.000
Lead	Pb	471	0.0000005		0.0002
Carbon Dioxide	CO_2	471	116.98		55,095.7
Greenhouse Gases	CO_2e	471	117.10		55,152.6

Footnotes

1. CO and NO_x emissions during normal operation are calculated based on concentrations of 4 and 2.3 parts per million, dry volume basis (ppmdv) corrected to 15% excess oxygen according to the following equations from 40 CFR Part 60, Appendix A, Reference Method 19, Eq. 19-1 and 40 CFR Part 75, Appendix F, Eq. F-5:

$$E_{NOx} = K_{NOx}\, C_d\, F_d\, \frac{20.9}{20.9-\%O_{2d}} \qquad E_{CO} = K_{CO}\, C_d\, F_d\, \frac{20.9}{20.9-\%O_{2d}}$$

Where, E = Pollutant emission rate, lb/mmBtu
C_d = Pollutant concentration during unit operation, parts per million, dry volume basis
F_d = 8,710 dscf/mmBtu for natural gas
$\%O_2$ = Oxygen concentration, percent by volume, dry basis, = 15%
K_{CO} = 7.237×10^{-8} lb/dscf-ppm CO
K_{NOx} = 1.194×10^{-7} lb/dscf-ppm NO_x

2. PM emissions are based on a proposed BACT emission rate of 7.0 pounds per hour, equal to 0.015 lb/mmBtu at 100% load.
3. All filterable plus condensable PM_{10} emissions are also assumed to be $PM_{2.5}$ emissions.
4. Sulfur dioxide (SO_2) emissions are based on the emission factor for the combustion of pipeline natural gas from the Acid Rain Program in 40 CFR Part 75 of 0.0006 lb SO_2/mmBtu.
5. VOC emissions are based on a proposed emission limit of 0.005 lb/mmBtu.
6. Lead (Pb) emissions are based on the emission factor from the U.S. EPA's *AP-42*, Table 1.4-2.
7. The emission factors for greenhouse gases including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

TABLE 3-2. Maximum emission rates for each LM6000PC CT during startup and shutdown.

Pollutant		Startup			Shutdown			TOTAL SU/SD EMISSIONS	
		Duration	Heat Input	Emissions	Duration	Heat Input	Emissions		
		minutes	mmBtu	lb	minutes	mmBtu	lb	lb / mmBtu	lb / event
Carbon Monoxide	CO	30	199.6	15.7	9	33.7	16.6	0.138	32.3
Nitrogen Oxides	NO_x	30	199.6	15.4	9	33.7	3.0	0.064	18.4
Particulate Matter	PM	30	199.6	2.99	9	33.7	0.51	0.015	3.5
Particulate Matter	PM_{10}	30	199.6	2.99	9	33.7	0.51	0.015	3.5
Particulate Matter	$PM_{2.5}$	30	199.6	2.99	9	33.7	0.51	0.015	3.5
Sulfur Dioxide	SO_2	30	199.6	0.1	9	33.7	0.02	0.0006	0.1
Vol. Org. Compounds	VOC	30	199.6	1.8	9	33.7	0.9	0.012	2.7
Sulfuric Acid Mist	H_2SO_4	30	199.6	0.0	9	33.7	0.00	0.000	0.0
Fluorides (F)	F	30	199.6	0.0	9	33.7	0.00	0.000	0.0
Lead	Pb	30	199.6	0.0	9	33.7	0.00	0.000	0.0
Carbon Dioxide	CO_2	30	199.6	23,348.4	9	33.7	3,942.1	117.0	27,290.5
Greenhouse Gases	CO_2e	30	199.6	23,372.5	9	33.7	3,946.2	117.1	27,318.7

TABLE 3-3. Potential emissions for each new GE LM6000PC CT based on the proposed limits in this application.

Pollutant		Heat Input	Normal Operation					Startup / Shutdown Operation			Total Potential to Emit
		mmBtu/hr	lb/mmBtu	ppm @ 15% O_2	lb/hr	mmBtu/yr	ton/yr	lb/event	event/yr	ton/yr	ton/yr
Carbon Monoxide	CO	471	0.00894	4.0	4.21	783,900	3.50	32.30	540	8.72	12.23
Nitrogen Oxides	NO_x	471	0.00848	2.3	3.99	783,900	3.32	15.00	540	4.05	7.37
Particulate Matter	PM	471	0.015		7.00	783,900	5.83	3.47	540	0.94	6.76
Particulate Matter	PM_{10}	471	0.015		7.00	783,900	5.83	3.47	540	0.94	6.76
Particulate Matter	$PM_{2.5}$	471	0.015		7.00	783,900	5.83	3.47	540	0.94	6.76
Sulfur Dioxide	SO_2	471	0.0006		0.28	783,900	0.24	0.09	540	0.03	0.24
Vol. Org. Compounds	VOC	471	0.0055		2.60	783,900	2.16	2.70	540	0.73	2.88
Sulfuric Acid Mist	H_2SO_4	471	0.000046		0.022	783,900	0.02	0.0072	540	0.00	0.018
Fluorides (F)	F	471	0.0000		0.000	783,900	0.0000	0.0000	540	0.0000	0.0000
Lead	Pb	471	0.0000005		0.00024	783,900	0.00020	0.00008	540	0.00002	0.00020
Carbon Dioxide	CO_2	471	117.0		55,096	783,900	45,848.8	27,291	540	7,368.4	45,848.8
Greenhouse Gases	CO_2e	471	117.1		55,153	783,900	45,896.1	27,319	540	7,376.1	45,896.1

Footnotes

The emission rates for PM, PM_{10}, and $PM_{2.5}$, SO_2, sulfuric acid mist, lead (Pb), CO_2, and GHG emissions, expressed in pounds per million Btu of heat input (lb/mmBtu), are NOT elevated during periods of startup and shutdown. Therefore, the total mass emissions for these pollutants, expressed in tons per year, may be based only on heat input and the respective pollutant emission rate, expressed in lb/mmBtu.

3.4 Natural Gas Piping Systems.

Natural gas piping components including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections can leak and result in fugitive natural gas emissions. Since natural gas consists of from 70 to almost 100% methane, leaks in the natural gas piping can result in methane emissions, and methane is a regulated greenhouse gas.

The Mandatory Greenhouse Gas Reporting Rules in 40 CFR Part 98, Subpart W include methods for estimating GHG emissions from petroleum and natural gas systems. Table 3-4 summarizes the estimated fugitive methane emissions and the equivalent GHG emissions, expressed as CO_2e, which are expected to result from a properly operated and maintained natural gas piping system for new CTs.

Note that these fugitive methane emissions represent less than 0.8% of the total GHG emissions from the proposed Project.

TABLE 3-4. Potential fugitive emissions from the natural gas piping systems.

Component Type	Component Count	Emission Factor[1] scf / hour / component	Specific Volume[3] scf / lb CH_4	Natural Gas (Methane)[4] ton/year	CO_2e Factor[2]	Potential to Emit ton CO_2e / year
Connectors	70	0.017	19.8	0.26	25	6.6
Flanges	2,000	0.003	19.8	1.33	25	33.2
Valves	2,160	0.123	19.8	58.86	25	1,471.6
Open Ended Pipes	70	0.123	19.8	1.91	25	47.7
Pump/Compressor Seals	20	13.3	19.8	58.93	25	1,473.4
Relief Valves		0.193	19.8	0.00	25	0.0
TOTAL				**121.0**	**25**	**3,025.9**

Footnotes

1. The emission factors are default whole gas emission factors from 40 CFR Part 98, Table W-1A for onshore natural gas production, Western U.S. In accordance with Table W-1A Footnote 1, for multi-phase flow that includes gas, use the gas service emissions factors.
2. The specific volume of methane at 68 °F is based on a specific volume of 385.5 standard cubic feet per lb-mole of gas, and a methane molecular weight of 16.0 lb/lb-mole.
3. Methane emissions are based on the worst-case assumption that natural gas is 100% methane by volume.

3.5 Sulfur Hexafluoride (SF_6) Insulated Electrical Equipment

Under the Prevention of Significant Deterioration (PSD) program sulfur hexafluoride (SF_6), Chemical Abstract Service (CAS) No. 2551-62-4, is also listed as regulated GHG. The new Project will include circuit breakers and switch gear for the CTs which will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, inert, and non-toxic gas. SF_6 has a very stable molecular structure and has a very high ionization energy which makes it an excellent electrical insulator. The gas is used for electrical insulation, arc suppression, and current interruption in high-voltage electrical equipment.

The electrical equipment containing SF_6 is designed not to leak, because if too much gas leaks out, the equipment may not operate correctly and could become unsafe. State-of-the-art circuit breakers are gas-tight and are designed to achieve a leak rate of less than or equal to 0.5% per year (by weight). This is the same leak rate from the U.S. EPA report, *SF_6 Leak Rates from High Voltage Circuit Breakers - EPA Investigates Potential Greenhouse Gas Emission Source*, J. Blackman, Program Manager, EPA, and M. Avery, ICF Consulting, and Z. Taylor, ICF Consulting. This is also the International Electrotechnical Commission (IEC) maximum leak rate standard.

Table 3-5 summarizes the potential SF_6 emissions for the planned equipment based on this leak rate. Note that these emissions represent 0.06% of the total GHG emissions from the proposed Project.

TABLE 3-5. Potential fugitive SF_6 emissions from high voltage electrical equipment and the equivalent GHG emissions.

Breaker Type	Breaker Count	Total SF_6 per Component pounds	Leak Rate % per year	SF_6 Emissions ton/year	CO_2e Factor[4]	Potential to Emit ton CO_2e /yr
500 kV	2	1,437	0.5%	0.0072	23,900	171.7
230 kV	5	189	0.5%	0.0024	23,900	56.5
145 kV		90	0.5%	0.0000	23,900	0.0
13.8 kV		35	0.5%	0.0000	23,900	0.0
TOTAL FUGITIVE EMISSIONS				**0.0095**	**23,900**	**228.2**

Footnotes

Potential emissions are based on the International Electrotechnical Commission (IEC) maximum leak rate standard of 0.5% per year.

3.6 Total Project Potential PSD and NANSR Regulated Air Emissions.

Table 3-6 summarizes the potential emissions with controls for the new GE LM6000PC CTs, the natural gas piping systems, and the SF_6 insulated electrical equipment based on the proposed emission and operating limits in this application.

TABLE 3-6. Total potential PSD regulated air pollutants for the Redhawk Power Plant Natural Gas-Fired Simple Cycle Combustion Turbine Expansion Project.

Pollutant		Eight (8) CTs Combined ton/yr	Natural Gas Piping Systems ton/yr	SF_6 Insulated Equipment	Total Project ton/yr
Carbon Monoxide	CO	95.0			95.0
Nitrogen Oxides	NO_x	59.0			59.0
Particulate Matter	PM	54.1			54.1
Particulate Matter	PM_{10}	54.1			54.1
Particulate Matter	$PM_{2.5}$	54.1			54.1
Sulfur Dioxide	SO_2	1.9			1.9
Volatile Organic Compounds	VOC	23.1			23.1
Sulfuric Acid Mist	H_2SO_4	0.14			0.14
Fluorides (F)	F	0.0000			0.0000
Lead	Pb	0.0016			0.0016
Carbon Dioxide	CO_2	366,790.2			366,790.2
Greenhouse Gases	CO_2e	367,169.0	3,025.9	228.2	370,423.0

3.7 Potential Hazardous Air Pollutant (HAP) Emissions.

Table 3-7 is a summary of the potential hazardous air pollutant (HAP) emissions for each new CT, and for all eight (8) CTs combined. The emission factors for all HAPs except formaldehyde (CH_2O) emissions during normal operation are based on uncontrolled emission factors from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, Volume 1: Section 3.1, Stationary Gas Turbines for Electricity Generation. Formaldehyde (CH_2O) emissions during normal operation are based on the emission limit of 91 parts per billion (ppbdv) or less at 15% O_2 for new, lean premix and diffusion-flame natural gas and oil-fired combustion turbines located at major sources of HAPs in accordance with the *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 CFR 63, Subpart YYYY. This emission concentration is equal to an emission rate of 0.000235 lb/mmBtu.

In the preamble to the proposed rules for Subpart YYYY, the U.S. EPA stated[1]:

> The only add-on HAP emission control technology identified in the original NESHAP rulemaking was an oxidation catalyst. No new or improved add-on control technologies that reduce HAP emissions from turbines were identified during the technology review. Our review also did not identify any new or improved operation and maintenance practices, process changes, pollution prevention approaches, or testing and monitoring techniques for stationary combustion turbines.

APS is proposing to install and operate oxidation catalyst systems on the proposed CTs in this application. The U.S. EPA's recent Information Collection Request (ICR), which was conducted recently in a reconsideration rulemaking for Subpart YYYY, has several test reports for General Electric (GE) LM6000PC units at the Middletown Power LLC Generating Plant in Middletown, Connecticut[2]. These tests were conducted in September 2022 on similar CTs also equipped with oxidation catalyst systems. The test results indicated average formaldehyde emission rates of 35.55 ppbdv at 15% O_2 on Unit 13, and 28.38 ppbdv at 15% O_2 on Unit 15. These emission rates are approximately one-third of the Subpart YYYY emission limit. Based on the U.S. EPA's evaluation of formaldehyde from similar CTs under Subpart YYYY, APS has concluded that the normal operation formaldehyde emission rate of 91 ppbdv at 15% O_2, except during turbine startup, equal to an emission rate of 0.000235 lb/mmBtu, is a conservative estimate of the maximum normal operation formaldehyde emissions from the proposed CTs in this application.

During periods of startup and shutdown, formaldehyde emissions may be elevated because the CTs are not operating in their full lean premix firing mode. During these periods, formaldehyde emissions in Table 3-7 are based on the uncontrolled emission factor of 0.000714 lb/mmBtu from AP-42, Section 3.1 noted above. The heat input rate during periods of startup and shutdown of 233.3 mmBtu per event is from Table 3-2.

---

[1] Federal Register, Vol. 84, No. 71, Friday, April 12, 2019, page 15063.

[2] https://www.epa.gov/stationary-sources-air-pollution/stationary-combustion-turbines-national-emission-standards (see Survey Test Reports Part 2 (zip).

TABLE 3-7. Potential hazardous air pollutant (HAP) emissions for each new CT and for all eight (8) CTs combined based on the proposed emission limits in this application.

POLLUTANT	CAS No.	Normal Operation					Startup and Shutdown Operation					Total Potential to Emit
		Emission Factor	Each CT		Eight (8) CTs Combined		Emission Factor	Each CT		Eight (8) CTs Combined		
		lb/mmBtu	mmBtu/hr	lb/hr	mmBtu/yr	ton/yr	lb/mmBtu	mmBtu	lb/SUSD	SU/SD/yr	ton/yr	ton/yr
Acetaldehyde	75-07-0	0.000040	471	0.0188	6,271,200	0.125	0.000040	233.3	0.0093	4,320	0.020	0.146
Acrolein	107-02-8	0.000006	471	0.0030	6,271,200	0.020	0.000006	233.3	0.0015	4,320	0.003	0.023
Benzene	71-43-2	0.000012	471	0.0057	6,271,200	0.038	0.000012	233.3	0.0028	4,320	0.006	0.044
1,3-Butadiene	106-99-0	0.000000	471	0.0002	6,271,200	0.001	0.000000	233.3	0.0001	4,320	0.000	0.002
Ethylbenzene	100-41-4	0.000032	471	0.0151	6,271,200	0.100	0.000032	233.3	0.0075	4,320	0.016	0.116
Formaldehyde	50-00-0	0.000215	471	0.1015	6,271,200	0.676	0.000714	233.3	0.1666	4,320	0.360	1.035
Xylene	1330-20-7	0.000001	471	0.0006	6,271,200	0.004	0.000001	233.3	0.0003	4,320	0.001	0.005
Naphthalene	91-20-3	0.000002	471	0.0010	6,271,200	0.007	0.000002	233.3	0.0005	4,320	0.001	0.008
PAH		0.000029	471	0.0137	6,271,200	0.091	0.000029	233.3	0.0068	4,320	0.015	0.106
Propylene oxide	75-56-9	0.000130	471	0.0612	6,271,200	0.408	0.000130	233.3	0.0303	4,320	0.066	0.473
Toluene	108-88-3	0.000064	471	0.0301	6,271,200	0.201	0.000064	233.3	0.0149	4,320	0.032	0.233
TOTAL		**0.000533**		**0.25**	**6,271,200**	**1.67**	**0.001031**		**0.24**	**4,320**	**0.520**	**2.19**

Footnotes

1. The emission factors for all HAPs except formaldehyde emissions during normal operation are *uncontrolled* emission factors from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, Volume 1: Stationary Point and Area Sources, Section 3.1, Stationary Gas Turbines for Electricity Generation. Formaldehyde emissions during startup and shutdown are based on the AP-42 emission factor.

2. Formaldehyde (CH_2O) emissions during normal operation are based on the emission limit of 91 parts per billion (ppbdv) or less at 15% O_2 for lean premix and diffusion-flame natural gas and oil-fired CTs located at major sources of HAPs in accordance with the *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 CFR 63, Subpart YYYY.

Chapter 4. Proposed Emission Limits.

With this application, APS requests the following emission limits be incorporated into the Redhawk Power Plant permit for the construction and operation of eight (8) new General Electric Model LM6000PC aeroderivative simple cycle combustion turbine (CT) electric generating units with water spray power augmentation, identified as Units 3 - 10.

4.1 Emission Limits for Each CT, Units 3 - 10.

4.1.1 Emission Limits

1. Excluding periods of startup and shutdown, the Permittee shall not cause to be discharged into the atmosphere from the simple cycle combustion turbines (CTs) Units 3 – 10 any gases which contain:
    a. Nitrogen oxides (NO_x) emissions in excess of 2.3 ppmvd corrected to 15 percent oxygen, based on a 1-hour average (limit is based on BACT/LAER).
    b. Carbon monoxide (CO) emissions in excess of 4.0 ppmvd corrected to 15 percent oxygen, based on a 24-hour average.
    c. Volatile organic compound (VOC) emissions in excess of 2.6 pounds per hour.
2. The Permittee shall not cause to be discharged into the atmosphere from the simple cycle combustion turbines (CTs) Units 3 – 10 any gases which contain:
    a. PM, PM_{10}, or $PM_{2.5}$ emissions in excess of 7.0 pounds per hour (limit is based on BACT).
    b. Visible emissions in excess of 20% opacity, as measured using U.S. EPA Reference Method 9.
    c. CO_2 emissions may not exceed 1,450 lb CO_2 per MWh of gross electric output for all periods of operation, including periods of startup and shutdown, based on a 12-operating month rolling average.

4.1.2 Startup and Shutdown (SU/SD).

1. "Startup" is defined as the period beginning with the ignition of fuel and ending 30 minutes later.
2. "Shutdown" is defined as the period beginning with the initiation of combustion turbine shutdown sequence and lasting until fuel combustion has ceased.
3. The total NO_x emissions during any hour, including periods of startup and shutdown, may not exceed 36.2 pounds per hour (BACT/LAER).

4.1.3 Operating Limits.

1. The total heat input to each combustion turbine, Units 3 – 10, may not exceed 783,900 mmBtu in any rolling 12-month period.

4.2 Emission Limits for All Eight CTs, Units 3 – 10 Combined.

1. Carbon monoxide (CO) emissions from the combustion turbine Units 3 – 10 combined may not exceed 95 tons in any rolling 12-month period for all periods of operation, including startup and shutdown. Compliance with this limit shall be demonstrated using a CO continuous emissions monitoring systems (CEMS).
2. Nitrogen oxides (NO_x) emissions from the combustion turbine Units 3 – 10 combined may not exceed 60 tons in any rolling 12-month period for all periods of operation, including periods of startup and shutdown. Compliance with this limit shall be demonstrated using a NO_x continuous emissions monitoring systems (CEMS).
3. Volatile organic compound (VOC) emissions from the combustion turbine Units 3 – 10 combined may not exceed 23 tons in any rolling 12-month period for all periods of operation, including periods of startup and shutdown. Compliance with this limit shall be demonstrated using records of fuel use data, startup/shutdown events, emission factors from stack tests, and an emission factor of 2.7 lbs per startup/shutdown event.

4.3 Initial Compliance Demonstration Requirements.

1. Within 60-days after achieving maximum production rate of each CT Units 3 - 10 but no later than 180 days after the initial start-up of each CT, the Permittee shall conduct performance tests using standard test methods as specified below or equivalent methods as approved by the MCAQD. These tests shall be performed at the maximum practical production rate of each unit. The performance tests shall include:

a.	Carbon monoxide (CO) emissions:	40 CFR Part 60, App. A-4, Ref. Method 10.
b.	Nitrogen oxides (NO_x) emissions:	40 CFR Part 60, App. A-4, Ref. Method 7E.
c.	PM_{10}, $PM_{2.5}$ emissions:	40 CFR Part 60, App. A-3, Ref. Method 5 and 40 CFR Part 51 App. M, Ref. Method 202.

4.4 Monitoring and Compliance Demonstration Requirements.

1. The Permittee shall install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) for the measurement of carbon monoxide (CO) emissions on Units 3 - 10. The CO CEMS shall be installed and operated in accordance with the requirements in 40 CFR Part 60, Appendix B, Performance Specification 4A or 4B.
2. The Permittee shall install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) for the measurement of nitrogen oxides (NO_x) on Units 3 - 10. The NO_x CEMS shall be installed and operated in accordance with the requirements in 40 CFR Part 75.
3. The Permittee shall install, calibrate, maintain, and operate a continuous monitoring system for the measurement of fuel (natural gas) used in Units 3 - 10. The monitoring

systems shall be installed and operated in accordance with the requirements in 40 CFR Part 75, Appendix D.

4.5 Standards of Performance for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKK.

1. Nitrogen oxides (NO_x) emissions may not exceed:
   a. 25 ppm at 15 percent O_2 or 1.2 lb/MWh based on a 4-hour rolling average when a valid NO_x emission rate is obtained for at least 3 of the 4 hours,
   b. 96 ppm at 15 percent O_2 or 4.7 lb/MWh when operating at less than 75 percent of peak load, or when operating at temperatures less than 0 °F.
2. Sulfur dioxide (SO_2) emissions may not exceed:
   a. 0.90 pounds of SO_2 per megawatt-hour of gross output or
   b. 0.060 lb SO_2/mmBtu heat input.
3. Install, certify, and operate a NO_x continuous emissions monitoring system (NO_x CEMS) in accordance with 40 CFR Part 75 Appendix A. (40 CFR §§ 60.4335(b) and 60.4345(a))

4.6 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTT.

1. Carbon dioxide (CO_2) emissions may not exceed 120 lb/MMBtu of heat input as determined by the procedures in 40 CFR § 60.5525.

Chapter 5. Applicable Requirements.

5.1 Minor New Source Review (NSR) Air Permitting Requirements.

In accordance with County Rule 241 §102.2, minor new source (NSR) review permitting requirements are applicable to a modification that would increase the source's potential to emit equal to or greater than the minor NSR modification thresholds. The minor NSR program requires the application of the Best Available Control Technology (BACT) or Reasonably Available Control Technology (RACT), as required by Rule 241, Sections 304 or 305, for each new emissions unit. The minor NSR threshold levels for any new or modified stationary source are summarized below. The proposed Project's potential to emit, the minor NSR BACT threshold levels, and the minor NSR applicability are summarized in Table 5-1. From Table 5-1, this Project will exceed the minor NSR BACT thresholds for NO_x, PM_{10}, and $PM_{2.5}$ emissions. However, in accordance with Rule 241, Section 103, the provisions of this rule shall not apply if the emissions are subject to major source requirements under Rule 240. Because this Project will be subject to Rule 240 for NO_x, PM_{10}, and $PM_{2.5}$ emissions, these pollutants are not subject to review under the minor NSR program.

TABLE 5-1. Total new stationary source potential emissions, the minor NSR threshold levels under Rule 241, and minor NSR applicability. All emissions are tons per year.

Pollutant		Total Potential to Emit	Minor NSR Threshold	OVER?	Minor NSR BACT Threshold	OVER?
Carbon Monoxide	CO	95.0	50	**YES**	100	**NO**
Nitrogen Oxides	NO_x	59.0	20	**YES**	40	**YES**
Particulate Matter	PM_{10}	54.1	7.5	**YES**	15	**YES**
Particulate Matter	$PM_{2.5}$	54.1	5	**YES**	10	**YES**
Sulfur Dioxide	SO_2	1.9	20	**NO**	40	**NO**
Volatile Organic Compounds	VOC	23.1	20	**YES**	40	**NO**

5.2 Major New Source Review (NSR) Air Permitting Requirements.

The Redhawk Power Plant in Maricopa County is classified as attainment for all criteria air pollutants except ozone. Maricopa County and the proposed site are classified as a marginal nonattainment area for the 8-hour ozone standard. However, the area may soon be reclassified as a serious nonattainment area.

5.2.1 Prevention of Significant Deterioration of Air Quality (PSD) Program.

The Prevention of Significant Deterioration of Air Quality (PSD) program in the Code of Federal Regulations, in 40 CFR §52.21 and County Rule 240, Section 305 requires that a major modification of a major stationary source within an attainment area must undergo PSD review and obtain a construction permit prior to commencing construction. In accordance with 40 CFR §52.21(b)(2)(i), a major modification means any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source.

Table 5-2 is a summary of the potential emissions for all PSD (and NANSR) regulated pollutants based on the proposed emissions and operating limits in this application. From Table 5-2, the Project will result in significant emissions increase and a significant net emissions increase of NO_x, PM, PM_{10}, $PM_{2.5}$, and greenhouse gas (GHG) emissions from the Redhawk Power Plant. Therefore, this Project is subject to PSD review for NO_x, PM, PM_{10}, $PM_{2.5}$, and GHG emissions, and the proposed Project will require the application of the Best Available Control Technology (BACT) for these pollutants. ***Note that NO_x emissions (as NO_2) are regulated both as a PSD pollutant as NO_2 and also as an ozone nonattainment area NANSR pollutant.***

TABLE 5-2. Potential emissions for the proposed new Project and PSD or NANSR applicability. All emissions are tons per year.

Pollutant		Total Project Potential to Emit	PSD / NANSR Significant Threshold	OVER?
Carbon Monoxide	CO	95.0	100	**NO**
Nitrogen Oxides	NO_x	59.0	40	**YES**
Particulate Matter	PM	54.1	25	**YES**
Particulate Matter	PM_{10}	54.1	15	**YES**
Particulate Matter	$PM_{2.5}$	54.1	10	**YES**
Sulfur Dioxide	SO_2	1.9	40	**NO**
Volatile Organic Compounds	VOC	23.1	40	**NO**
Sulfuric Acid Mist	H_2SO_4	0.14	7	**NO**
Fluorides (F)	F	0.0000	3	**NO**
Lead	Pb	0.0016	0.6	**NO**
Carbon Dioxide	CO_2	366,790.2	n/a	**n/a**
Greenhouse Gases	CO_2e	370,302.4	75,000	**YES**

5.2.2 Nonattainment Area New Source Review (NANSR) Program.

Maricopa County and the Redhawk Power Plant are classified as a marginal nonattainment area for the 8-hour ozone standard. The regulated ozone nonattainment area pollutants are NO_x and VOC. Major modifications of a major stationary source are also subject to review under the permit requirements for new major sources or major modifications located in nonattainment areas in County Rule 240, Section 304 which incorporates 40 CFR §51.165(a)(1). A major modification to a major stationary source in a marginal ozone nonattainment area is a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase NO_x or VOC emissions.

For a marginal ozone nonattainment area, the significant threshold for both NO_x and VOC emissions is 40 tons per year. From Table 5-2, the proposed project will result in significant emissions increase and a significant net emissions increase for NO_x emissions. Therefore, this Project is subject to NANSR review for NO_x emissions, and the proposed Project will require the application of the Lowest Achievable Emission Rate (LAER) and emission offsets for NO_x emissions. This application includes a LAER analysis for NO_x emissions in Chapter 7 and an emissions offset analysis in Chapter 10. Note that if the area is reclassified as a serious nonattainment area, the significant threshold for both NO_x and VOC emissions is reduced to 25 tons per year.

5.3 Standards of Performance for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKK.

In 2006, the U.S. EPA finalized the *Standards of Performance for Stationary Combustion Turbines* under 40 CFR 60, Subpart KKKK. In accordance with 40 CFR § 60.4300, combustion turbines which commenced construction, modification, or reconstruction after February 18, 2005 are subject to this subpart. The pollutants regulated under Subpart KKKK include NO_x and sulfur dioxide (SO_2). The proposed natural gas-fired simple cycle stationary CTs meet the affected facility definition under this standard. Therefore, the following NSPS requirements will apply to the proposed CTs.

5.3.1 Sulfur Dioxide (SO_2) Emissions.

The applicable new SO_2 emission standard for the proposed simple cycle CTs under Subpart KKKK are:

> **§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?**
>
> (a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.
>
> (1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;
>
> (2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement;

The applicable limits are 0.90 pounds of SO_2 per megawatt-hour of gross output or 0.060 lb SO_2/mmBtu heat input. The combustion of pipeline natural gas will meet this emission standard.

5.3.2 Nitrogen Oxides (NO_x) Emissions.

The NO_x emission standards under 40 CFR § 60.4320 are specified in Subpart KKKK, Table 1. The standards for new, modified, or reconstructed turbines firing natural gas and with a heat input greater than 50 mmBtu/hr and less than or equal to 850 mmBtu/hr is 25 ppm at 15 percent O_2 or 1.2 pounds per MWh of useful output. For these combustion turbines which use the mechanical and thermal energy output of the CTs only to produce electricity, the gross useful output is the gross electrical output from the turbine/generator set.

Excerpts from Table 1 to 40 C.F.R. Part 60, Subpart KKKK: NO_X emission limits for new stationary combustion turbines.

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas.	Greater than 50 mmBtu/hr and less than or equal to 850 mmBtu/hr	25 ppm at 15 percent O_2 or 1.2 lb/MWh
Turbines operating at less than 75% of peak load, … and turbine operating at less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 4.7 lb/MWh.

APS is proposing to install a NO_x continuous emissions monitoring system (NOx CEMS) in accordance with the requirements in the federal Acid Rain Program in 40 CFR Part 75. In accordance with the Subpart KKKK requirements in 40 CFR § 60.4380 **How are excess emissions and monitor downtime defined for NOx?**, subparagraph (b), an excess emission is defined as:

> **§ 60.4380 How are excess emissions and monitor downtime defined for NO_X?**
>
> (b) For turbines using continuous emission monitoring, as described in §§ 60.4335(b) and 60.4345:
>
> (1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in § 60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

Therefore, the applicable NO_x emission limits under Subpart KKKK are:

1. 25 ppm at 15 percent O_2 or 1.2 lb/MWh based on a 4-hour rolling average when a valid NO_x emission rate is obtained for at least 3 of the 4 hours, and
2. 25 ppm at 15 percent O_2 or 1.2 lb/MWh based on a 30-operating day rolling average.
3. 96 ppm at 15 percent O_2 or 4.7 lb/MWh when operating at less than 75 percent of peak load, or when operating at temperatures less than 0 °F

The proposed BACT/LAER NO_x emission limit of 2.3 ppmdv at 15% excess oxygen based on a 1-hour average is more stringent than the NO_x emissions standards under Subpart KKKK.

5.3.3 General Compliance Requirement under 40 CFR § 60.4333.

Under 40 CFR § 60.4333, the CTs, the SCR, and the oxidation catalyst air pollution control equipment and monitoring equipment must be operated and maintained in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

5.3.4 NO_x Monitoring Requirements under 40 CFR § 60.4335.

The compliance monitoring requirements of Subpart KKKK allows the use of NO_x monitoring methods that are required under the federal Acid Rain Program in 40 CFR Part 75. APS proposes to install and certify a NO_x continuous emission monitoring systems (NO_x CEMS) consisting of a NO_x monitor and a diluent gas oxygen (O_2) monitor to determine the hourly NO_x emission rate in ppm corrected to 15% O_2 in accordance with the requirements of 40 CFR Part 75.

5.3.5 SO_2 Monitoring Requirements under 40 CFR § 60.4360 and § 60.4365.

Subpart KKKK also allows for several acceptable monitoring methods to demonstrate compliance with the SO_2 emission limits. To be exempted from fuel sulfur monitoring requirements, APS must demonstrate that the potential sulfur emissions expressed as SO_2 are less than 0.060 lb/mmBtu for continental US areas. The demonstration can be made by providing information from a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas use is 20 grains of sulfur or less per 100 standard cubic feet. The demonstration can also be made using representative fuel sampling data which show that the sulfur content does not exceed 0.060 lb SO_2/mmBtu. The fuel sampling data specified in 40 CFR Part 75, Appendix D, section 2.3.1.4 or 2.3.2.4 may be used to make this demonstration under Subpart KKKK.

5.3.6 Performance Tests under 40 CFR § 60.4400.

Initial performance testing is required in accordance with 40 CFR §60.8. Subsequent performance tests must be conducted on an annual basis. As described in §60.4405, the NO_x CEMS RATA tests may be used as the initial NO_x performance test. The SO_2 performance test may be a fuel analysis of the natural gas, performed by the operator, fuel vendor, or other qualified agency. The required test methods are detailed in 40 CFR §60.4415.

5.3.7 Reporting Requirements under 40 CFR § 60.4375.

For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, reports of excess emissions and monitor downtime must be submitted in accordance with 40 CFR § 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. Paragraphs § 60.4380 and § 60.4385 describe how excess emissions are defined for Subpart KKKK.

For each affected unit that conducts annual performance tests in accordance with § 60.4340(a), a written report of the results of each performance test must be submitted before the close of business on the 60th day following the completion of the performance test.

5.4 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTT.

These CTs may also be subject to the *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*, 40 CFR 60 Subpart TTTT. The applicable carbon dioxide (CO_2) requirement in Subpart TTTT, Table 2 are summarized below.

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu).
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO_2/GJ of heat input (120 lb/MMBtu) to 69 kg CO_2/GJ of heat input (160 lb/MMBtu) as determined by the procedures in § 60.5525.

However, the CO_2 emissions standards in 40 CFR 60.5520(d)(1) states:

> (1) Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (i.e., uniform fuels) that result in a consistent emission rate of 160 lb CO_2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. **These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel.** Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

Therefore, while these CTs are subject to the standards in 40 CFR 60 Subpart TTTT, in accordance with 40 CFR 60.5520(d)(1), there would be no monitoring or reporting requirements for either natural gas or diesel fuel oil-fired CTs under Subpart TTTT.

5.5 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTTa *(proposed)*.

In May 2023, the U.S. EPA proposed revised new source performance standards (NSPS) for GHG emissions from new fossil fuel-fired stationary combustion turbine EGUs. Upon promulgation of 40 CFR part 60, subpart TTTTa, stationary combustion turbines that commence construction or reconstruction after May 23, 2023 and meet the relevant applicability criteria will be subject to 40 CFR part 60, subpart TTTTa. For new and reconstructed fossil fuel-fired combustion turbines, EPA is proposing to create three subcategories based on the function the combustion turbine serves:

1. Low load ("peaking units") subcategory that consists of combustion turbines with a capacity factor of less than 20 percent;
2. Intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the combustion turbine;
3. Base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines.

For the low load subcategory, EPA is proposing that the best system of emissions reduction (BSER) is the use of lower emitting fuels (e.g., natural gas and distillate oil) with standards of performance ranging from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on the type of fuel combusted.

With this application, APS is proposing to limit the heat input to each CT to a capacity factor of 19.4% which will make these CTs low load or peaking units under Subpart TTTTa[3].

5.6 Acid Rain Program.

In accordance with the applicability requirements of the Acid Rain Program in 40 CFR § 72.6(a)(3)(i), a *utility unit* that is a *new unit* shall be an affected unit:

> **§ 72.6 Applicability.**
>
> (a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program:
>
> (1) A unit listed in table 1 of § 73.10(a) of this chapter.
>
> (2) A unit that is listed in table 2 or 3 of § 73.10 of this chapter and any other existing utility unit, except a unit under paragraph (b) of this section.
>
> (3) A utility unit, except a unit under paragraph (b) of this section, that:
>
> (i) Is a new unit;

Under 40 CFR § 72.2, "utility unit" and "new unit" mean:

> *Utility unit means a unit owned or operated by a utility:*
>
> *(1) That serves a generator in any State that produces electricity for sale, or*
>
> *(2) That during 1985, served a generator in any State that produced electricity for sale.*
>
> *New unit* means a unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25 MWe or less or that is a simple combustion turbine.

Since these CTs would produce electricity for sale, they are "utility units." The definition of "new unit" includes a unit that commences commercial operation on or after November 15, 1990, including a simple combustion turbine. "Simple combustion turbines" and "Unit" are subsequently defined as:

> *Simple combustion turbine* means a unit that is a rotary engine driven by a gas under pressure that is created by the combustion of any fuel. This term includes combined cycle units without auxiliary firing. This term excludes combined cycle units with auxiliary firing, unless the unit did not use the auxiliary firing from 1985 through 1987 and does not use auxiliary firing at any time after November 15, 1990.
>
> *Unit* means a fossil fuel-fired combustion device.

These CTs would be fossil fuel-fired combustion devices that commenced commercial operation on or after November 15, 1990. These new CTs would also be simple combustion turbine devices, and they are also utility units. Therefore, these new CTs will be affected units under the Acid Rain Program. APS will submit an Acid Rain Permit application to EPA and provide a copy to Maricopa County Air Quality Department (MCAQD).

---

[3] APS reserves the right to request a different limit should the subcategories promulgated in the final rule differ materially from the proposed subcategories.

5.7 National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines 40 CFR Part 63, Subpart YYYY.

The *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 CFR Part 63, Subpart YYYY apply to new sources located at a major source of hazardous air pollutants (HAPs). A major stationary source of HAPs is any stationary source with potential emissions of any individual HAP of more than 10 tons per year, or any stationary source with total potential HAP emissions of more than 25 tons per year. The Redhawk Power Plant is currently a minor or area source of HAPs.

In accordance with 40 CFR §63.6090(b)(4), existing CTs which commenced construction or reconstruction on or before January 14, 2003 do not have to meet the requirements of this subpart. No initial notification is necessary for any existing CT. In accordance with 40 CFR § 63.6090(a)(2), a stationary combustion turbine is new if you commenced construction of the stationary combustion turbine after January 14, 2003.

Table 5-3 is a summary of the total potential HAP emissions for the Redhawk Power Plant after the addition of the new simple cycle CT Units 3 – 10. From Table 5-3, the total potential HAP emissions after the installation of the new CTs are less than 10 tons per year for each individual HAP, and less than 25 tons per year for all HAPs combined. Therefore, the Redhawk Power Plant will remain a minor or area source after this Project, and the standards under 40 CFR Part 63 Subpart YYYY do not apply to the new (or existing) units.

TABLE 5-3. Total potential hazardous air pollutant emissions for the Redhawk Power Plant with the addition of the new simple cycle CT Units 3 - 8. All emissions are tons per year.

Hazardous Air Pollutant	CAS No.	Unit CC1	Unit CC2	New CT Units 3 - 10	Fire Pump	Cooling Towers	Total Potential to Emit
Acetaldehyde	75-07-0	0.042	0.042	0.146	0.00028		0.23
Acrolein	107-02-8	0.080	0.080	0.023	0.00003		0.18
Benzene	71-43-2	0.090	0.090	0.044	0.00034		0.22
1,3-Butadiene	106-99-0	0.005	0.005	0.002	0.00001		0.01
Ethylbenzene	100-41-4	0.090	0.090	0.116			0.30
Formaldehyde	50-00-0	0.444	0.444	1.035	0.00043		1.92
Hexane		0.305	0.305				0.61
Naphthalene	91-20-3	0.016	0.016	0.005			0.04
PAH		0.028	0.028	0.008	0.00006		0.06
Propylene	115-07-1				0.00103		0.00
Propylene Oxide	75-56-9	0.364	0.364	0.106			0.83
Toluene	108-88-3	1.630	1.630	0.473	0.00015		3.73
Xylene	1330-20-7	0.180	0.180	0.233	0.00010		0.59
TOTAL		**3.275**	**3.275**	**2.190**	**0.00243**	**0.000**	**8.74**

5.8 40 CFR 64 – Compliance Assurance Monitoring.

The Compliance Assurance Monitoring (CAM) program is codified in 40 CFR Part 64. CAM plan requirements apply to any pollutant specific emissions unit with uncontrolled potential emissions above the major source threshold of 100 tons per year that uses a control device to achieve compliance with an emission limitation or standard. Uncontrolled NO_x and CO emissions for the eight (8) simple cycle CTs exceed this threshold.

With respect to NO_x emissions, the new CTs will be subject to 40 CFR 60 Subpart KKKK and are also affected units under the Acid Rain Program in 40 CFR Part 72 – 75. In accordance with the CAM applicability requirements in 40 CFR § 64.2(b)(1)(i) and (iii), the CAM plan requirements do not apply to emission units subject to these programs.

There are no specific applicable requirements for CO emissions from these CTs under a New Source Performance Standard (NSPS) or under any National Emission Standard for Hazardous Air Pollutants (NESHAP). APS is proposing to use CEMS for monitoring CO emissions from the proposed units. In accordance with 40 CFR § 64.3(d)(2)(ii), the use of a CO CEMS that is installed and operated in accordance with 40 CFR Part 60 and Appendix B of Part 60 shall be deemed to satisfy the general design criteria CAM plans.

Chapter 6. Control Technology Review Methodology.

6.1 Best Available Control Technology (BACT).

The Clean Air Act defines "best available control technology" (BACT) as:

> "…an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under this paragraph as it existed prior to November 15, 1990."

Under the Maricopa County Air Pollution Control Regulations, Rule 100, Section 200.25, "best available control technology" (BACT) means:

200.25 BEST AVAILABLE CONTROL TECHNOLOGY (BACT): An emissions limitation, based on the maximum degree of reduction for each pollutant, subject to regulation under the Act, which would be emitted from any proposed stationary source or modification, which the Control Officer, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of such pollutant. Under no circumstances shall BACT be determined to be less stringent than the emission control required by an applicable provision of these rules or of any State or Federal laws ("Federal laws" include the EPA approved State Implementation Plan (SIP)). If the Control Officer determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The BACT requirement applies for a given pollutant to each individual new or modified emission unit when the project, on a facility-wide basis, has a significant net emissions increase for that pollutant. Individual BACT determinations are performed on a unit-by-unit, pollutant-by-pollutant basis.

6.2 Top Down BACT Methodology.

The United States Environmental Protection Agency (U.S. EPA) recommends a "top-down" approach in conducting a BACT or Lowest Available Emission Rate (LAER) analysis. This method evaluates progressively less stringent control technologies until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The five steps of a top-down BACT analysis are:

1. Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;
2. Eliminate all technically infeasible control technologies;
3. Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
4. Evaluate most effective controls and document results; and
5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The impact analysis of any BACT review includes an evaluation of environmental, energy, technical, and economic impacts. The net environmental impact associated with a control alternative may be considered if dispersion modeling analyses are performed. The energy impact analysis estimates the direct energy impacts of the control alternatives in units of energy consumption. If possible, the energy requirements for each control option are assessed in terms of total annual energy consumption. The economic impact of a control option is assessed in terms of cost effectiveness and ultimately, whether the option is economically reasonable. The economic impacts are reviewed on a cost per ton controlled basis, as directed by the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual, Fifth Edition.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decisions.

6.3 Technical Feasibility.

Step 2 of the BACT analysis involves the evaluation of all of the identified available control technologies from Step 1 to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option.

The technology must be commercially available for it to be considered as a candidate for BACT. EPA's New Source Review Workshop Manual, page B.12 states, "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

In general, if a control technology has been "demonstrated" successfully for the type of emission source under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. Page B.17 of the New Source Review Workshop Manual states:

> Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.
>
> Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:
>
> - concept stage;
> - research and patenting;
> - bench scale or laboratory testing;
> - pilot scale testing;
> - licensing and commercial demonstration; and
> - commercial sales.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission source), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission source may not be applicable to a similar source depending on differences in gas stream characteristics.

6.4 Economic Feasibility.

Economic feasibility is normally evaluated according to the average and incremental cost effectiveness of the control option. From the U.S. EPA's New Source Review Manual, page B.31, average cost effectiveness is the dollars per ton of pollutant reduced. The incremental cost effectiveness is the cost per ton reduced from the technology being evaluated as compared to the next lower technology. The EPA NSR Review Manual states that, "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those sources and the particular source under review".

In addition to the average and incremental cost effectiveness analysis, EPA has also used direct comparisons of control technology costs to overall project costs as part of recent GHG BACT determinations. Regarding economic impacts, in its PSD GHG BACT guidance EPA states[4]:

[4] EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases,* (Mar. 2011), page 42.

> EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.

The U.S. EPA evaluated the costs of CCS in its Response to Public Comments (October, 2011) for the Palmdale Hybrid Power Project, a 570 MW power plant based on approximately 520 MW of natural gas-fired combined cycle units and 50 MW of solar photovoltaic systems. In the EPA's analysis, the estimated capital costs for the Project are $615-$715 million, equal to an annualized cost of about $35 million over the 20 year lifetime of the facility. In comparison, the estimated annual cost for CCS for this Project is about $78 million, ***or more than twice the value of the facility's annual capital costs***. Based on these very high costs, EPA eliminated CCS as an economically infeasible control option. The EPA's decision to reject CCS based on these very high annual costs was upheld on appeal by the U.S. EPA's Environmental Appeals Board (EAB), PSD Appeal No. 11 -07, decided September 17, 2012.

The EAB also rejected a challenge to a PSD permit for the construction of a new ethylene production unit in Baytown, Texas. The EAB upheld the determination that the installation of CCS was too expensive, on a total cost basis, to be selected as BACT for limiting GHG emissions from the proposed unit.

6.4.1 Average Cost Effectiveness.

In the EPA's New Source Review Manual, page B.37, average cost effectiveness is calculated as:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emission rate} - \text{Control option emissions rate}}$$

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. In the draft Workshop Manual, the EPA states that the baseline emission rate represents uncontrolled emissions for the source. However, the manual also states that when calculating the cost effectiveness of adding controls to inherently lower emitting processes, baseline emissions may be assumed to be the emissions from the lower emitting process itself.

6.4.2 Incremental Cost Effectiveness.

In addition to determining the average cost effectiveness of a control option, the U.S. EPA's New Source Review Manual states that the incremental cost effectiveness between dominant control options should also be calculated. The incremental cost effectiveness compares the costs and emissions performance level of a control option to those of the next most stringent control option:

$$\text{Incremental Cost (\$ per incremental ton removed)} = \frac{\text{Control option annualized cost} - \text{Next control option annualized cost}}{\text{Next control option emission rate} - \text{Control option emissions rate}}$$

6.5 Alternative to Top-Down BACT Analysis

In the Maricopa County Air Quality Permitting Handbook, August 2023, MCAQD states that to streamline the BACT selection process, MCAQD will accept BACT for the same or similar source category as listed by the South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Air Pollution Control District (SJVAPCD), the Bay Area Air Quality Management District (BAAQMD), or another regulatory agency accepted by MCAQD as a viable alternative.

If an owner or operator of a source opts to select control technology for the same or similar source category accepted by the air quality management districts in California, the owner or operator may forego conducting the top-down BACT analysis.

6.6 Scope of the Control Technology Review.

The U.S. EPA has a longstanding policy regarding the scope of control technology options which the review agency may consider in a control technology review or BACT analysis. The scope of potential options relates directly to a proposed project's basic purpose or design. In short, the list of options should not include processes or options that would fundamentally redefine the source proposed by the applicant.

In the U.S. EPA EAB decision on the Prairie State Generating Station, PSD Appeal No. 05-05, the EAB explained (pages 27-28) that the facility's "basic purpose" or basic design," as defined by the applicant, is the fundamental touchstone of EPA's policy on "redefining the source":

> …Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through the application of BACT. The parties' arguments, properly framed in light of their agreement on this central proposition, thus concern the proper demarcation between those aspects of a proposed facility that are subject to modification through the application of BACT and those that are not.
>
> We see no fundamental conflict in looking to a facility's basic "purpose" or to its "basic design" in determining the proper scope of BACT review, nor do we believe that either approach is at odds with past Board precedent.

This EAB decision was upheld by the United States Court of Appeals, 7th Circuit.[5]

When EPA issued guidance in 2011 for conducting control technology reviews for greenhouse gas (GHG) emissions, EPA confirmed that a BACT analysis should not redefine the source's purpose:[6]

---

[5] *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

[6] U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases* 26 (Mar. 2011) (citing *Prairie State*, 13 E.A.D. at 23).

> While Step 1 [of a BACT process] is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include lower pollution processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

The EAB has analyzed the redefinition of the source concept in the context of a past permitting proceeding similar to the proposed Project. In their challenges to a PSD permit issued for the Pio Pico Energy Center, petitioners asserted before the EAB that EPA had erred in eliminating combined-cycle gas turbines in Step 2 of its BACT analysis for GHG emissions. Like the proposed project, Pio Pico is a simple cycle gas-fired facility designed to back up renewable generation by providing peaking and load-shaping capability. As the EAB recognized in its Pio Pico decision and consistent with EPA guidance, a permitting authority can consider peaking facilities, intermediate load facilities and base load facilities to be different electricity generation source types. The EAB explained how "plants operating in 'peaking mode' typically remain idle much of the time but can be started up when power demand increases … and, unlike base load plants, typically use simple-cycle rather than combined-cycle units as well as smaller turbines."[7]

The U.S. EPA has also addressed the issue of whether a peaking facility must consider energy storage such as batteries in the control technology review. In the U.S. EPA's Environmental Appeals Board (EAB) decision for the APS Ocotillo Power Plant[8], the EAB stated that "Maricopa County did not abuse its discretion when it determined that pairing energy storage at this facility would "redefine the source", making the following statements and conclusions.

> But Step 1's broad look is "not without limits." *Id*. Consideration of fundamentally different facility types than those proposed by permit applicants generally is not required. Indeed, EPA guidance and Board precedent, affirmed by the U.S. Court of Appeals for the Seventh Circuit, give permitting authorities the discretion to exclude a proposed control alternative from consideration in the BACT analysis, if that proposed alternative would "redefine the design of the source."

The EAB went on to state (page 336):

> As explained in *La Paloma*, to determine whether an emissions control option would fundamentally redefine a proposed source, permit issuers should begin by examining how the permit applicant defines the proposed facility's "end, object, aim, or purpose," i.e., its "basic design." That "basic design" typically is set forth in the permit application and supporting materials in the administrative record. *Id*. at 286; *accord Palmdale*, 15 E.A.D. at 731; *Desert Rock*, 14 E.A.D. at 530; *Prairie State*, 13 E.A.D. at 21-23. The permit issuer should then take a "hard look" at the applicant's "basic design," identifying design elements that are "inherent" to the applicant's purpose and design elements that possibly could be altered to achieve pollutant emissions reductions without disrupting that purpose.

---

[7] *In re Pio Pico Energy Center*, PSD Appeal Nos. 12-04 through 12-06, slip op. at 63 (EAB Aug. 2, 2013).

[8] In Arizona Public Services Company, PSD Appeal No. 16-01, Order Denying Review, September 1, 2016 page 328.

The EAB concluded this issue stating:

> The administrative record in this case supports Maricopa County's conclusion that integrating energy storage into the Ocotillo project would interfere with Arizona Public Service's ability to meet its customers' needs for "rapid, reliable power," as that option likely would not allow Arizona Public Service to meet "short peak demand[s]," "several short peak demands in a row," or "extended peak demand[s]" on an "immediate basis." *See* RTC at 8-9. For example, Sierra Club concedes on appeal that the paired energy storage option it advocates would not allow Arizona Public Service to fire the turbines to maximum capacity in 2 minutes. Pet. at 16 & n.12. As such, the option would not fulfill Arizona Public Service's project purpose. Maricopa County reasonably determined that energy storage would not be adequate to stabilize the electrical grid, as necessary in a situation with a large and growing proportion of intermittent power sources such as solar and wind. *See* RTC at 11-12. The record supports a determination that these aspects of the facility's design are inherent ones, central to Arizona Public Service's business purpose in proposing the Ocotillo Modernization Project, and Maricopa County appropriately identified them as such. *Id*. at 8-9, 11-12.

In the U.S. EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[9] issued for a peaking facility to be comprised of reciprocating internal combustion engines (RICE), EPA determined that "energy storage cannot be required in the Step 1 BACT analysis as a matter of law." *Id.* at 1 (explaining that "'incorporating energy storage' in Step 1 of the BACT analysis for a [RICE] resource would constitute the consideration of an alternative means of power production in violation of long-established principles for what can occur in Step 1 of the BACT analysis") (citing *Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007)). EPA concluded that energy storage, either "to replace all or part of the proposed . . . project," would fundamentally redefine the source. *Id.* at 2.

Like this Project, the purpose of the Red Gate project was to provide reliable, rapidly dispatchable power to support renewables and the transmission grid. Because "energy storage first requires separate generation and the transfer of the energy to storage to be effective . . . [it] is a fundamentally different design than a RICE resource that does not depend upon any other generation source to put energy on the grid." *Id.* Energy storage could not meet that production purpose for the duration or scale needed. *Id.* at 2-3. As EPA correctly observed, "[t]he nature of energy storage and the requirement to replenish that storage with another resource goes against the fundamental purpose of the facility." *Id.* at 3.

Similarly, in another PSD permit for a peaking facility for the Shady Hills Generating Station (Jan 2014), this time with natural gas-fired simple cycle units, EPA also concluded that energy storage would not meet the business purpose of the facility and therefore should not be considered in the BACT analysis. [10]

---

[9] *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions, PSD-TX-1322-GHG (Nov. 2014), http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-resp2sierra-club.pdfNov%2014 .

[10] Responses to Public Comments, Draft Greenhouse Gas PSD Air Permit for the Shady Hills Generating Station at 10-11 (Jan 2014), http://www.epa.gov/region04/air/permits/ghgpermits/shadyhills/ShadyHillsRTC%20_011314.pdf.

Chapter 7. Nitrogen Oxides (NO_x) Control Technology Review.

Nitrogen oxides (NO_x) consist of both nitrogen oxide (NO), and nitrogen dioxide (NO_2). During combustion, NO usually accounts for about 90% of the total NO_x emissions. However, since NO is converted to NO_2 in the atmosphere, the mass emission rate of NO_x is usually reported as NO_2.

NO_x is formed during combustion by two major mechanisms; thermal formation (Thermal NO_x), and fuel formation (Fuel NO_x). Thermal NO_x results from the high temperature oxidation of nitrogen (N_2) and oxygen (O_2). In this mechanism, N_2 is supplied from air, which is 78% N_2 by volume. Thermal NO_x formation increases exponentially with temperature, becoming significant at temperatures above 2800 °F. Fuel NO_x results from the oxidation of organic nitrogen compounds in the fuel. Because fuel bound nitrogen is more easily converted to NO_x during combustion, nitrogen levels in fuel have a significant impact on NO_x formation. However, since natural gas has only trace organic nitrogen compounds, thermal NO_x is the primary source of NO_x emissions from natural gas-fired gas turbines.

7.1 BACT Baseline.

The standards of performance for stationary gas turbines under 40 CFR Part 60, Subpart KKKK regulate emissions from these CTs. The applicable standards are described in Chapter 4 and are summarized below.

1. 25 ppm at 15 percent O_2 or 1.2 lb/MWh based on a 4-hour rolling average when a valid NO_x emission rate is obtained for at least 3 of the 4 hours,
2. 25 ppm at 15 percent O_2 or 1.2 lb/MWh based on a 30-operating day rolling average, and
3. 96 ppm at 15 percent O_2 or 4.7 lb/MWh when operating at less than 75 percent of peak load, or when operating at temperatures less than 0 °F.

7.2 BACT Control Technology Determinations.

The following BACT / LAER determinations are for simple cycle CTs. As discussed in detail in the greenhouse gas BACT analysis in Chapter 9, section 9.5.3 of this application, combined cycle CTs are not included in this control technology analysis because combined cycle CTs do not meet the purpose and need of this project, and because the high temperature selective catalytic reduction (SCR) systems required for simple cycle CTs cannot achieve the NO_x emission rates that low temperature SCR systems can achieve on combined cycle CTs.

Table 7-1 is a summary of the BACT/LAER determinations from the South Coast Air Quality Management District (SCAQMD) and the Bay Area Air Quality Management District (BAAQMD). The lowest determination has a BACT emission limit of 2.3 ppmdv at 15% O_2.

Table 7-2 is a summary of BACT determinations from the U.S. EPA's RACT/BACT/LAER Clearinghouse. Also included in Table 7-2 is the Ocotillo Power Plant. From both Tables 7-1 and 7-2, the most stringent NO_x emission limit for similar simple cycle CTs is 2.3 ppmdv at 15% O_2, based on a 1-hour average.

TABLE 7-1. NO_x LAER / BACT determinations for natural gas-fired simple cycle CTs.

Agency	Emission Unit Description	NOx Limit ppmdv at 15% O_2	Averaging Period
SCAQMD	General Electric LM6000PC 49.8 MW simple cycle CT equipped with SCR.	2.3	1-Hour
SCAQMD	General Electric LMS100PA 100 MW simple cycle CTs equipped with SCR.	2.5	1-Hour
BAAQMD 89.1.3	Simple cycle CTs greater than 40 MW with water injection and SCR.	2.5	

TABLE 7-2. NO_x BACT limits for simple-cycle, natural gas-fired gas turbines.

Facility	State	Permit Date	NO_x Limit, ppmdv at 15% O_2	Averaging Period
Bayonnne Energy Center	NJ	2018	2.5	3-hour
Troutdale Energy Center, LLC	OR	2016	2.5	3-hour
Perryman Generating Station	MD	2016	2.5	3-hour
Ocotillo Power Plant	AZ	2015	2.5	1-hour
Pio Pico Energy Center	CA	2012	2.5	1-hour
Walnut Creek Energy Park	CA	2011	2.5	1-hour

Footnotes

WI means water injection; SCR means selective catalytic reduction.

7.3 STEP 1. Identify All Available Control Technologies.

Recent BACT determinations from the U.S. EPA's RACT/BACT/LAER Clearinghouse and the review of literature indicates four major control technologies used to control NO_x emissions:

1. Water Injection (WI),
2. Dry low NO_x (DLN) combustion,
3. Selective Catalytic Reduction (SCR), including hot SCR
4. EMx™ Catalytic Absorption process (EMx or SCONOx™)
5. Selective non-catalytic reduction (SNCR).

7.3.1 Water Injection (WI).

The proposed GE LM6000PC CTs will be equipped with water injection which is designed to reduce turbine exhaust NO_x levels prior to the inlet to the SCR systems to 25 ppmdv at 15% O_2.

7.3.2 Dry low NO_x (DLN) Combustion.

Dry Low NO_x (DLN) combustion is available for the LM6000 CTs, but the proposed CTs use water injection and also utilize water spray power augmentation which injects water into the CT to increase mass flow and increase the CT power output. As a result, DLN equipped LM6000 CTs have a lower peak electric generating capacity than the water injected units. This reduction in peak generating capacity directly affects the ability of the project to meet its basic design requirements. Furthermore, DLN combustion has a significantly lower turndown capability for these CTs. Therefore, DLN combustion is not technically feasible for these peaking units. And in any case, the same level of NO_x control is expected with both water injection and DLN combustion.

7.3.3 Selective Catalytic Reduction (SCR).

Selective Catalytic Reduction (SCR) is a flue gas treatment technique for the reduction of NO_x emissions which uses an ammonia (NH_3) injection system and a catalytic reactor. An SCR system utilizes an injection grid which disperses NH_3 in the flue gas upstream of the catalyst. NH_3 reacts with NO_x in the presence of the catalyst to form nitrogen (gas) and water according to the following general equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

Catalysts are substances which evoke chemical reactions that would otherwise not take place, and act by providing a reaction mechanism that has a lower activation energy than the uncatalyzed mechanism. For SCR, the catalyst is usually a noble metal, a base metal (titanium or vanadium) oxide, or a zeolite-based material. Noble metal catalysts are not typically used in SCR because of their very high cost. To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to critical temperature considerations, the NH_3 injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x. Excessive ammonia injection will result in NH_3 emissions, called ammonia slip.

SCR has the capability to make substantial reductions in NO_x emissions. For these simple cycle CTs, the use of SCR is expected to reduce NO_x emissions by more than 90%.

7.3.4 Selective Non-Catalytic Reduction (SNCR).

In a selective non-catalytic reduction (SNCR) control system, urea or ammonia is injected into boilers where the flue gas temperature is approximately 1,600 °F to 2,100 °F. At these temperatures, urea [$CO(NH_2)_2$] or ammonia [NH_3], reacts with NO_x, forming elemental nitrogen [N_2] and water without the need for a catalyst. The overall NO_x reduction reactions are similar to those for SCR. Multiple injection points are required to thoroughly mix the reagent into the boiler furnace. The limiting factor for an SNCR system is the ability to contact NO_x with the reagent without resulting in excessive ammonia slip, and without excessive ammonia decomposition before the NO_x emissions can be reduced.

SNCR has been widely used in circulating fluidized bed (CFB) boilers where the high alkaline ash loading of the CFB boilers makes 'high dust' loading SCR systems technically infeasible. However, the time and temperature range for SNCR is not compatible with CTs. We are not aware of the application of SNCR to any gas turbine either in the U.S. or worldwide. Therefore, SNCR is not a technically feasible control technology for the Paris gas turbines.

7.3.5 EMx™ Catalytic Absorption/Oxidation (formerly SCONOx™).

EMx™ Catalytic Absorption/Oxidation (the second-generation of the SCONOx™ NOx Absorber technology) is based on a proprietary catalytic oxidation and absorption technology. EMx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce NO_x and CO emissions from natural gas fired gas turbines. The catalyst oxidizes carbon monoxide (CO) to carbon dioxide (CO_2), and nitric oxide (NO) to nitrogen dioxide (NO_2). The NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Dilute hydrogen gas is periodically passed across the surface of the catalyst to regenerate the K_2CO_3 catalyst coating. The regeneration cycle converts KNO_2 and KNO_3 to K_2CO_3, water (H_2O), and elemental nitrogen (N_2). This makes the K_2CO_3 available for further absorption and the water and nitrogen are exhausted.

ABB Alstom Power purchased a proprietary technology called SCONOx™ from Goal Line Environmental Technologies. A SCONOx™ system has been in operation since December of 1996 on the 30 MW Sun Law Energy Federal cogeneration plant in Vernon, California. Since August of 1999, SCONOx has been in operation on a 5 MW cogeneration plant at Genetics Institute in Andover, Massachusetts. The Redding Electric Utility in Redding, California installed a SCONOx™ system on a 43 MW combined cycle plant in 2002. ABB Alstom Power subsequently completed design of a scaled-up SCONOx™ system for 100 MW and greater combined cycle gas turbines.

A significant advantage of SCONOx™ is that it does not require ammonia or urea as a reagent. However, SCONOx™ is designed for operation at temperatures of 300 °F to 700 °F. Therefore, SCONOx™ has potential application to combined cycle and cogeneration gas turbines which have lower exhaust gas temperatures than simple cycle CTs. This operating range is too low for the exhaust gas temperatures from the proposed LM6000 CTs. Therefore, EMx™ Catalytic Absorption/Oxidation is not a technically feasible control option for these CTs.

7.4 STEP 2. Identify Technically Feasible Control Technologies.

The following NO_x control technologies were identified for natural gas-fired CTs. Based on the discussion in Step 1, Water Injection, Selective Catalytic Reduction, and EMx™ Catalytic Absorption process are technically feasible control options.

Control Technology	Technical Feasibility	Basis
1. Water Injection (WI).	Feasible	Proposed Technology
2. Dry low NO_x (DLN) combustion.	Infeasible	Lower peak generating capacity and reduced turndown capability cannot meet the Project's Purpose and Need.
3. Selective Catalytic Reduction (SCR).	Feasible	Proposed Technology
4. EMx™ Catalytic Absorption process (EMx or SCONOx™).	Feasible	Cannot reduce emissions below SCR rates.
5. Selective non-catalytic reduction (SNCR).	Infeasible	Time and temperature range required for SNCR is not compatible with CTs.

7.5 STEP 3. Rank the Technically Feasible Technologies.

Water injection combined with hot SCR is expected to achieve a NO_x emission rate of 2.3 ppmdv at 15% O_2. Limited data is available on the EMx™ Catalytic Absorption process, but the available data indicate that this technology cannot reliably reduce NO_x emissions below 3.0 ppmdv at 15% O_2.

7.6 STEP 4. Evaluate the Most Effective Controls.

APS proposes to utilize water injection combined with hot SCR which is the lowest emission rate technology. Therefore, further evaluation is unnecessary.

7.7 STEP 5. Proposed NO_x BACT/LAER Determination.

APS has concluded that the use of water injection in combination with the use of selective catalytic reduction (SCR) represents the best available control technology (BACT) and the Lowest Achievable Emission Rate (LAER) for the control of NO_x emissions from the proposed GE LM6000PC simple-cycle CTs. This BACT determination is the same as BACT determinations that have been approved by the South Coast Air Quality Management District (SCAQMD) and the and the Bay Area Air Quality Management District (BAAQMD). This BACT determination is also the lowest identified emission limit for similar simple cycle CTs in the U.S. EPA's RACT/BACT/LAER Clearinghouse.

7.7.1 Proposed BACT /LAER for Normal Operation.

Based on this analysis, APS proposes the following limits as the Best Available Control technology (BACT) and the Lowest Achievable Emission Rate (LAER) for the control of NO_x emissions from the new GE LM6000PC CTs:

1. Nitrogen oxide (NO_x) emissions may not exceed 2.3 parts per million, on a dry, volume basis (ppmdv) corrected to 15% O_2, based on a 1-hour average. This limit shall not apply during turbine commissioning, start-up, shutdown, and equipment tuning.

7.7.2 Proposed BACT/LAER Determination for Periods of Startup and Shutdown.

The CT air pollution control systems including the SCR and water injection systems are not operational during periods of startup and shutdown (SU/SD) because the exhaust gas temperatures are too low for these systems to function as designed. In addition, water injection used to control NO_x emissions cannot be used during startup because injecting water too soon can impact the CT flame stability and combustion dynamics, and it may also increase CO emissions. As a result, NO_x emissions may be elevated during periods of startup and shutdown. For periods of startup and shutdown, APS proposes the use of good combustion practices designed to expeditiously startup and shutdown the CTs to minimize NO_x emissions.

Water injection is used to reduce NO_x emissions from these CTs before the SCR systems. The earlier that water injection can be initiated during the startup process, the lower NO_x emissions will be during startup. However, if injection is initiated at very low loads, it can impact flame stability and combustion dynamics, and it may increase CO emissions. These concerns must be carefully balanced when determining when to initiate water injection. Oxidation catalysts and SCR pollution control systems are not functional during periods of startup and shutdown because the exhaust gas temperatures are too low for these systems to function as designed.

For simple cycle CTs, the time required for startup is much shorter than gas turbines used in combined cycle applications. The quick startup times for simple cycle CTs help minimize emissions during startup and shutdown events. For the proposed LM6000PC simple cycle CTs, the length of time for a normal startup, i.e., the time from initial fuel firing to the time that the unit goes on-line and water injection begins, is normally about 8 to 10 minutes. However, the SCR and oxidation catalyst pollution control systems are not fully operational until the temperature of the catalysts and exhaust gases in these systems is at the normal operating temperature. The time to achieve this temperature can be as long as 30 minutes from initial fuel firing. The length of time for a normal shutdown, i.e., the time from the cessation of water injection to the time when the flame is out, can be as long as 9 minutes. Therefore, the longest duration for a startup and shut down cycle or "event" is 39 minutes

Based on this analysis, APS proposes the following limits as BACT and LAER for the control of NO_x emissions from the new GE LM6000PC CTs during periods of startup and shutdown.

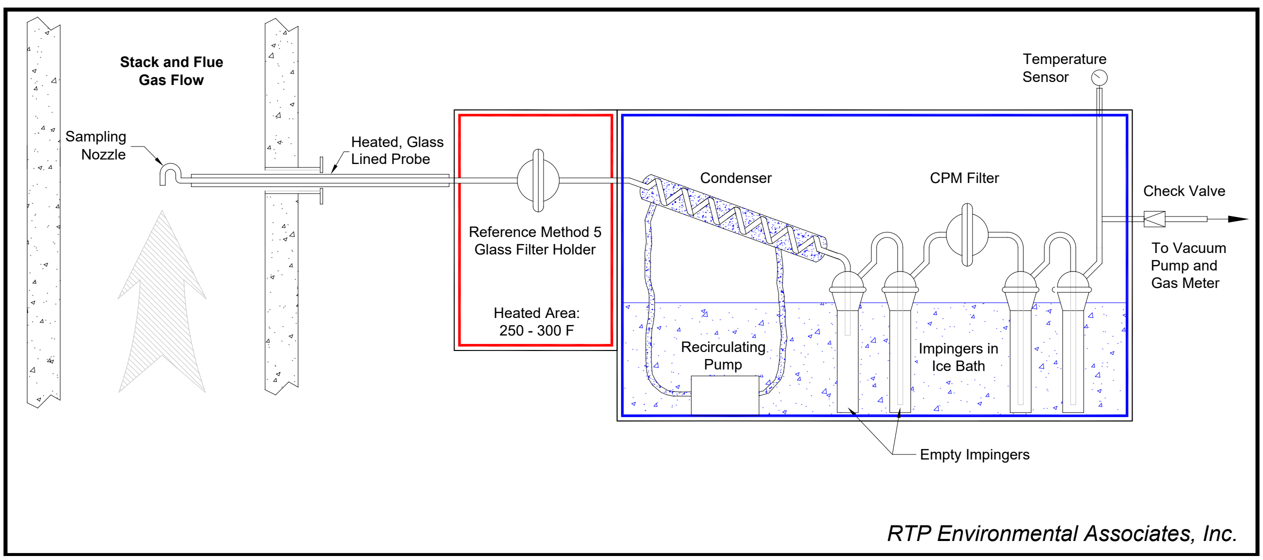
1. "Startup" is defined as the period beginning with the ignition of fuel and ending 30 minutes later.
2. "Shutdown" is defined as the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased.
3. The total NO_x emissions during any hour, including periods of startup and shutdown, may not exceed 36.2 pounds per hour.

Chapter 8. Particulate Matter, PM_{10}, and $PM_{2.5}$ Control Technology Review.

Emissions of particulate matter (PM), PM with particle sizes less than 10 microns (PM_{10}), and PM with particle sizes less than 2.5 microns ($PM_{2.5}$) from CTs result from PM in the combustion air, from ash in the fuel and injected water, and from products of incomplete combustion. For this analysis, all PM emissions from the CTs are also assumed to be PM_{10} and $PM_{2.5}$ emissions. Since natural gas has virtually no inorganic ash, fuel ash is not a significant source of PM emissions. As a result, the primary sources of PM emissions from these CTs are expected to result from products of incomplete combustion, from solids in the water used for water injection, turbine wear, and particulate matter in the ambient air.

PM which exists as a solid or liquid at temperatures of approximately 250 ^{o}F are measured using U.S. EPA's Reference Method 5 or 17 and are commonly referred to as "front half" emissions. PM which exists as a solid or liquid at the lower temperature of 32 ^{o}F are measured using U.S. EPA's Reference Method 202, and is commonly referred to as "back half" or "condensable" PM. Condensable PM may include acid gases such as sulfuric acid mist, volatile organic compounds (VOC) and other materials, but does not include condensed water vapor.

FIGURE 8-1. Reference Method 5 and Reference Method 202 sample train.



8.1 BACT Baseline.

There are currently no emission standards for combustion or gas turbines under the New Source Performance Standards.

8.2 BACT Control Technology Determinations.

In accordance with the *Maricopa County Air Quality Permitting Handbook*, August 2023, MCAQD will accept BACT for the same or similar source category as listed by the South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Air Pollution Control District (SJVAPCD), the Bay Area Air Quality Management District (BAAQMD), or another regulatory agency accepted by MCAQD as a viable alternative. We were only able to identify one BACT determination for PM_{10} emissions from the BAAQMD for simple cycle CTs larger than 40 MW. That determination, Document No. 89.1.3, identified "Exclusive use of CPUC-regulated grade natural gas" as the control technology.

Table 8-1 is a summary of PM emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database. Note that a number of the emission limits from the U.S. EPA's RBLC database are stated as a mass emission rate, expressed in pounds of PM per hour. The emission limits range from 0.0019 lb/mmBtu to 0.0171 lb/mmBtu.

TABLE 8-1. Recent PM BACT limits for simple-cycle, natural gas-fired gas turbines.

Facility	State	Permit Date	Throughput		Permit Limit, as Stated		Equivalent Calculated lb/mmBtu
Pio Pico Energy Center	CA	Feb-14	300	MW	0.0053	lb/mmBtu	0.0053
Westar Energy Emporia EC	KS	Mar-23	1780	mmBtu/hr	18	lb/hour	0.0101
Westar Energy Emporia EC	KS	Mar-23	405.3	mmBtu/hr	6	lb/hour	0.0148
Colbert Combustion Turbine Plant	AL	Mar-22	229	MW	0.008	lb/mmBtu	0.0080
LBWL Erickson Station	MI	Sep-21	667	mmBtu/hr	4.5	lb/hour	0.0067
Washington Parish Energy Center	LA	Jun-21	2201	mmBtu/hr	6.3	lb/hour	0.0029
Doswell Energy Center	VA	Jun-19	1961	mmBtu/hr	12	lb/hour	0.0061
Calcasieu Pass LNG Project	LA	Jun-19	927	mmBtu/hr	8	lb/hour	0.0086
Calcasieu Pass LNG Project	LA	Jun-19	263	mmBtu/hr	4.5	lb/hour	0.0171
Cove Point LNG Terminal	MD	May-18	130	MW	0.0033	lb/mmBtu	0.0033
Cove Point LNG Terminal	MD	May-18	130	MW	0.007	lb/mmBtu	0.0070
Waverly Facility	WV	May-18	1571	mmBtu/hr	15	lb/hour	0.0095
Montpelier Generating Station	IN	Nov-17	270.9	mmBtu/hr	0.0066	lb/mmBtu	0.0066
Lonesome Creek Gen. Station	ND	Jun-17	412	mmBtu/hr	5	lb/hour	0.0121
Invenergy Nelson Expansion LLC	IL	Apr-17	190	MW	0.005	lb/mmBtu	0.0050
R.M. Heskett Station	ND	Apr-17	986	mmBtu/hr	7.3	lb/hour	0.0074
Pioneer Generating Station	ND	Nov-16	451	mmBtu/hr	5.4	lb/hour	0.0120
Troutdale Energy Center, LLC	OR	May-16	1690	mmBtu/hr	9.1	lb/hour	0.0054
Midwest Fertilizer Corporation	IN	May-16	283	mmBtu/hr	0.0019	lb/mmBtu	0.0019

8.3 STEP 1. Identify All Available Control Technologies.

The following PM, PM_{10}, and $PM_{2.5}$ control technologies were identified for natural gas-fired CTs:

1. Water Injection,
2. Dry Low NO_x (DLN) Combustion,
3. Low Ash / Low Sulfur Fuel (i.e., natural gas and/or distillate fuel oil).
4. Post combustion control systems including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, cyclones, and multiclones.

The proposed LM6000PC CTs will be equipped with inlet air filters which remove dust and particulate matter from the inlet air. These CTs will also utilize water injection in which demineralized water is injected into the combustion section of the CT which reduces flame temperatures and reduces thermal NO_x formation. These CTs are also equipped with water spray power augmentation which injects demineralized water into the low-pressure compressor. This water flow increases the mass flow of gases through the turbines and results in higher electric power output. Both the inlet air and the demineralized water have the potential to result in PM emissions from these CTs.

Dry Low NO_x (DLN) combustion is available for the LM6000 CTs, but the proposed CTs use water spray power augmentation to increase mass flow and increase the CT power output. As a result, DLN equipped LM6000 CTs have a lower peak electric generating capacity than the water injected units. This reduction in peak generating capacity directly affects the ability of the project to meet its basic design requirements. Furthermore, DLN combustion has a significantly lower turndown capability for these CTs. Therefore, DLN combustion is not technically feasible for these peaking units. And in any case, it is unclear if any reduction in PM could be achieved through the use of DLN as compared to water injection.

The proposed CTs are internal combustion engines. Numerous other PM control systems are available for solid fuel-fired *external* combustion sources such as boilers and process heaters, including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones. However, we are not aware of any examples where these control systems have been applied to natural gas-fired CTs. This is because natural gas-fired CTs already have very low PM emission rates similar to or even less than the *controlled* emission rates from solid fuel-fired boilers after the use of these post combustion control systems. In addition, the high exhaust gas flowrates and high exhaust gas temperatures from simple cycle CTs are not compatible with these PM control technologies intended primarily for solid fuel-fired boilers.

8.4 STEP 2. Identify Technically Feasible Control Technologies.

The following PM, PM_{10}, and $PM_{2.5}$ control technologies were identified for natural gas-fired gas turbines:

1. Low Ash / Low Sulfur Fuel (i.e., natural gas)
2. Post combustion control systems including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, cyclones, and multiclones.

8.4.1 Low Ash / Low Sulfur Fuel.

PM, PM_{10}, and $PM_{2.5}$ emissions from CTs can be affected by ash and inorganic sediments in the fuel, and by the level of sulfur compounds in the fuel. While the inorganic ash and sediments may be emitted directly as particulate matter, sulfur compounds are emitted primarily as sulfur dioxide (SO_2). However, because of the high excess oxygen levels and high temperatures in the exhaust gas of CTs, SO_2 may be further oxidized to sulfur trioxide (SO_3). While SO_3 is a gas, SO_3 will spontaneously react with water when temperatures drop below the acid dew point to form sulfuric acid (H_2SO_4). Sulfuric acid mist is condensable PM, and, by definition, it is also a part of the $PM_{2.5}$ emissions.

Regardless of the reaction mechanisms, natural gas is a very low ash and a very low sulfur fuel. In fact, natural gas has the lowest ash and sulfur content of the available fossil fuels.

8.4.2 Post Combustion PM Control Systems.

As noted in Step 1, CTs are internal combustion engines. While numerous other PM control systems are available for solid fuel-fired *external* combustion sources such as boilers and process heaters, including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones, we are not aware of any examples where these control systems have been applied to natural gas-fired CTs. This is because natural gas-fired gas turbines already have very low PM emission rates similar to or even less than the *controlled* emission rates from solid fuel-fired boilers after the use of these post combustion control systems. In addition, the high exhaust gas flowrates and high exhaust gas temperatures from simple cycle gas turbines are not compatible with these PM control technologies intended for solid fuel-fired boilers.

Because there is no evidence that the use of post combustion PM control systems such as fabric filter baghouses could actually reduce the already very low PM emission rates from CTs, and because the exhaust gas temperatures from simple cycle CTs are much higher than the maximum design temperatures for these PM control systems, fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones are not technically feasible control technologies for the control of PM emissions from the proposed CTs.

8.5 STEP 3. Rank the Technically Feasible Technologies.

Based on the above analysis, the use of low ash and low sulfur containing fuels including natural gas is a technically feasible control option for these gas turbines. From Table 7-1, the use of this control is expected to achieve a PM, PM_{10}, and $PM_{2.5}$ emission rate in the range of 0.0019 lb/mmBtu to 0.0171 lb/mmBtu.

8.6 STEP 4. Evaluate the Most Effective Controls.

APS proposes to utilize the use of low ash and low sulfur fuel (natural gas) as the best available control technology. Other control options, including post combustion PM control systems, are not available and are technically infeasible control options. Therefore, further evaluation is unnecessary.

8.7 STEP 5. Proposed Particulate Matter (PM), and $PM_{2.5}$ BACT Determination.

APS has concluded that the use of low sulfur fuel (natural gas) represents the best available control technology (BACT) for the control of particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions from the proposed GE LM6000PC simple-cycle CTs. From the U.S. EPA's RACT/BACT/LAER database, the emission limits for similar natural gas-fired CTs range from 0.0019 lb/mmBtu to 0.0171 lb/mmBtu. Based on the full load heat input rate for the proposed CTs of 471 mmBtu/hr, these reported emission limits range from 0.9 to 8.0 lb/hr.

The U.S. EPA Region 9 originally established the PM_{10} and $PM_{2.5}$ Pio Pico Energy Center (PPEC) BACT limit at 0.0065 lb/mmBtu. In response to an Environmental Appeals Board decision, EPA revised their BACT analysis by reviewing the lowest permitted emission limits and recent stack test data for similar sized natural gas-fired CTs. Region 9 considered a number of technical factors with the potential to impact the reliability and usefulness of the stack test data in projecting achievable emissions. EPA noted that there was significant variability in the test data from the three facilities analyzed. In addition, data for two of the three facilities reviewed was from the initial compliance tests on new units, while for the third facility the emission units were only four years old. EPA noted in its analysis that CTs are expected to last more than 20 to 30 years. It is unclear how much PM emissions may vary as the equipment ages and therefore it would be inappropriate to rely only on this emissions data to set a limit that is achievable on an ongoing basis over the life of the equipment. Setting a BACT limit based on limited testing of new units may not address long-term achievable emissions.

EPA's review focused on three facilities that were all located in the same region and stated that because fuel sulfur content is one of the main contributors to PM emissions from gas turbines, and because the sulfur content in natural gas varies by region, that it was appropriate to use data from the same region in California as the PPEC for setting the PM emission limit. Sulfur in the natural gas will be oxidized to form sulfur dioxide (SO_2), and it may also be oxidized to form sulfur trioxide (SO_3). When the exhaust gas temperature reaches the acid dew point (which will only occur in the atmosphere or in a stack testing reference method sample train), SO_3 will react spontaneously with water to form sulfuric acid (H_2SO_4, $H_2SO_4 \cdot H_2O$, or $H_2SO_4 \cdot 2H_2O$). Sulfuric acid is "condensable" particulate matter which is measured using Reference Method 202 used for determining PM_{10} and $PM_{2.5}$ emissions. In addition, some of the sulfur dioxide in the sample flue gas may dissolve in the Method 202 sample train and eventually react with water to form sulfuric acid mist. This unintended reaction of SO_2 to form condensable particulate matter creates particulate matter which is an artifact of the reference method. In this context "artifact" means something observed (i.e., condensable particulate matter) in a scientific investigation or experiment (i.e., the reference method test) that is not naturally present but occurs as a result of the investigative procedure.

APS has reviewed information available for similar GE LM6000 CTs which are operated by APS at the Sundance Power Plant. These CTs are in the same region for purposes of representative natural gas. Table 8-2 is a summary of four (4) compliance emission tests for units at the Sundance Power Plant. From Table 8-2, compliance emission tests indicate total PM, PM_{10}, and $PM_{2.5}$ emission rates ranging from 0.004 to 0.013 lb/mmBtu.

TABLE 8-2. Compliance emission test results for particulate matter emissions from similar combustion turbines.

Unit	Date	PM_{10} Emission Rate, lb/mmBtu			
		Filterable	Condensable	Total	Total of Test
7	7/19/2018	0.002	0.002	0.004	
		0.001	0.001	0.003	
		0.002	0.002	0.004	0.004
6	7/18/2018	0.002	0.001	0.003	
		0.001	0.003	0.004	
		0.001	0.014	0.016	0.008
8	7/19/2012			0.008	
				0.015	
				0.015	0.013
4	7/17/2012			0.017	
				0.009	
				0.008	0.011
Average		**0.002**	**0.004**	**0.009**	**0.009**
Maximum		**0.002**	**0.014**	**0.017**	**0.013**
125% of Maximum					**0.015**

Because the proposed CTs have high excess oxygen levels, and because the CTs will be equipped with oxidation catalysts, relatively high percentages of SO_2 may be converted to SO_3. And based on compliance emission tests for similar CTs in the region which indicate total filterable plus condensable PM emission rates as high as 0.013 lb/mmBtu, APS has concluded that the achievable long term emission rate for the proposed CTs is 0.015 lb/mmBtu. At the full rated heat input capacity for the proposed CTs of 471 mmBtu per hour, this emission rate is equal to 7.0 pounds per hour.

Based on this analysis, APS proposes the following limits as the Best Available Control technology (BACT) for the control of particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions from the new GE LM6000PC CTs.

1. Particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions may not exceed 7.0 pounds per hour, based on a 3-hour average.

Chapter 9. Greenhouse Gas (GHG) Emissions Control Technology Review.

On May 13, 2010, the U.S. EPA issued a final "tailoring" rule that establishes requirements for greenhouse gas (GHG) emissions from stationary sources under the Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21. This rule sets thresholds for GHG emissions that establish when permits are required for new stationary sources under the PSD program. The final rule "tailors" the requirements of the PSD program to limit which facilities will be required to obtain PSD permits and meet substantive PSD program requirements for GHG emissions. After January 2, 2011, new major stationary sources that are subject to the PSD permitting program due to potential emissions of a pollutant other than GHGs would be subject to the PSD requirements for GHG emissions. GHG emission increases of 75,000 tons per year or more of total GHG, on a total CO_2 equivalent basis (CO_2e), will need to determine the Best Available Control Technology (BACT) for GHG emissions.

The final rule includes the following regulated GHG emissions:

1. Carbon dioxide (CO_2)
2. Methane (CH_4)
3. Nitrous oxide (N_2O)
4. Hydrofluorocarbons (HFCs)
5. Perfluorocarbons (PFCs)
6. Sulfur hexafluoride (SF_6)

From 40 CFR §98, Table A-1, the global warming potential for these pollutants are:

Name	Global Warming Potential (100 yr.)
1. Carbon dioxide (CO_2)	1
2. Methane (CH_4)	25
3. Nitrous oxide (N_2O)	298

The potential emission rate for each individual greenhouse gas is then multiplied by its global warming potential and summed to determine the total CO_2 equivalent emissions (CO_2e) for the source.

9.1 Project Operational Requirements.

As noted in the Purpose and Need in section 2.3 of this application, Arizona is experiencing significant growth in demand for energy generation to support residential, commercial, and industrial customer load growth. At the same time, summer energy supply is tightening in the western United States, making it difficult to purchase the required energy from the energy market. These new LM6000PC units, along with the solar and battery energy storage APS is adding to its resource portfolio, will help APS meet the more than 40% load growth that is expected in the next eight years. Having a variety of resources - including natural gas, nuclear, solar, energy storage, and customer demand response programs in APS's portfolio - makes the system more resilient to supply chain disruptions, extreme weather, and changing market conditions. Further, natural gas resources provide critical capacity during peak system demand and support reliability when customers need it most.

A critical component of this Project is that the proposed LM6000PC units are quick starting and fast ramping. These new CTs can be online in eight minutes and at full load in under 10 minutes - making them a critical resource to respond to fluctuations in renewable energy output throughout the day. Because these LM6000PC peaking units offer flexible, on-demand energy 24/7, they can provide much-needed energy during late afternoon and evening hours when customer demand is high, creating a strong complement to renewable energy resources such as solar. In short. the new units will support reliable electrical service when APS customers need it most.

APS is continuing to add renewable energy, especially solar energy, to the electric power grid. However, because renewable energy is an intermittent source of electricity, a balanced resource mix is essential to maintain reliable electric service. One of the major impediments to grid integration of solar generation is the variable nature of the power provided and how that variability impacts the electric grid. According to the Electric Power Research Institute (EPRI) study on the variability of solar power generation capacity, the total plant output for three large PV plants in Arizona have ramping events of up to 40% to 60% of the rated output power over 1-minute to 1-hour time intervals[11]. Considering only the solar capacity in Maricopa County, the required electric generating capacity ramp rate required to back up these types of solar systems is in the range of 165 to 310 MW per minute.

To back up the current and future renewable energy resources, the Project design requires quick start and power ramping capability to meet changing power demands and mitigate grid instability caused by the intermittency of renewable energy generation. To achieve these requirements, the project design is based on eight (8) General Electric (GE) LM6000PC natural gas-fired simple cycle CTs. The proposed CTs can provide an electric power ramp rate equal to 50 MW per minute per CT which is critical for the project to meet its purpose and need. When all 8 proposed CTs are operating at 50% load, the entire project can provide approximately 190 MW of ramping capacity in less than 2 minutes.

The proposed new LM6000PC units will also provide dynamic voltage control for the electric grid. Dynamic voltage control is the ability of a generating resource to maintain voltage levels within acceptable limits. This Project will also provide system electric inertia (kinetic energy stored during the units' operation) and frequency response (the ability of a generating resource to aid balance between generation and load on the grid) necessary for electric system stability. Batteries and renewable energy systems such as wind and solar cannot provide this necessary grid support. These attributes of the proposed CTs are critical when the electric supply resource portfolio includes more and more intermittent, renewable resources such as wind and solar.

---

[11] Electric Power Research Institute (EPRI) report, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, 3002001387, Technical Update, December 2013, conclusion, page 6-1.

9.2 Potential Greenhouse Gas (GHG) Emissions.

GHG emissions from natural gas-fired CTs include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The federal *Mandatory Greenhouse Gas Reporting Requirements* under 40 CFR Part 98 requires reporting of greenhouse gas (GHG) emissions from large stationary sources. Under 40 CFR Part 98, facilities that emit 25,000 metric tons or more per year of GHG emissions are required to submit annual reports to EPA. Table C-1 of this rule includes default emission factors for CO_2. The CO_2 emission factor for natural gas combustion is 53.06 kg per mmBtu, equal to 116.98 pounds per million Btu, based on the higher heating value (HHV) of natural gas.

Methane (CH_4) emissions result from incomplete combustion of natural gas. The federal *Mandatory Greenhouse Gas Reporting rule*, 40 CFR Part 98, Table C-2 lists a methane emission factor for natural gas combustion of 0.001 kg/mmBtu (0.0022 lb/mmBtu). The potential emission rate for methane is then multiplied by its global warming potential of 25 to determine the total CO_2e emissions, equal to 0.055 lb CO_2e per mmBtu of heat input.

Nitrous oxide (N_2O) emissions from gas turbines result primarily from low temperature combustion. The federal *Mandatory Greenhouse Gas Reporting rule*, 40 CFR Part 98, Table C-2 lists a default N_2O emission factor for natural gas combustion of 0.0001 kg/mmBtu (0.00022 lb/mmBtu). The potential emission rate for N_2O is then multiplied by its global warming potential of 298 to determine the total CO_2e emissions, equal to 0.066 lb CO_2e per mmBtu of heat input.

Potential GHG emissions for each CT based on the proposed operating limits in this permit application are summarized in Table 9-1. It is important to note that the emission rates for CO_2 and GHG emissions, expressed in pounds per million Btu of heat input (lb/mmBtu), are NOT elevated during periods of startup and shutdown. Therefore, total emissions may simply be based on the heat input of the CTs.

Because CO_2 emissions account for 99.9% of the GHG emissions from these CTs, this control technology review for GHG emissions will focus on CO_2 emissions.

TABLE 9-1. Potential GHG emissions for each CT based on the proposed emission limits in this application.

Pollutant		Emission Factor	Total GHG Emission Factor		Heat Input		Total GHG Emissions	
		lb / mmBtu	CO_2e Factor[4]	lb / mmBtu	mmBtu / hour	mmBtu / year	lb / hour	ton / year
Carbon Dioxide	CO_2	116.976	1	116.976	471	783,900	55,095.7	45,848.8
Methane	CH_4	0.0022	25	0.055	471	783,900	26.0	21.6
Nitrous Oxide	N_2O	0.00022	298	0.066	471	783,900	30.9	25.7
Total GHG Emissions	CO_2e	116.98		117.10	471	783,900	55,152.6	45,896.1

9.3 BACT Baseline.

9.3.1 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTT.

These CTs are subject to the *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*, 40 CFR 60 Subpart TTTT. The applicable carbon dioxide (CO_2) requirement in Subpart TTTT, Table 2 are summarized below.

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu).
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO_2/GJ of heat input (120 lb/MMBtu) to 69 kg CO_2/GJ of heat input (160 lb/MMBtu) as determined by the procedures in § 60.5525.

However, the CO_2 emissions standards in 40 CFR 60.5520(d)(1) states:

> (1) Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (i.e., uniform fuels) that result in a consistent emission rate of 160 lb CO_2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. **These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel.** Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

Therefore, while these CTs are subject to the standards in 40 CFR 60 Subpart TTTT, there would be no monitoring or reporting requirements for natural gas or diesel fuel oil-fired CTs under Subpart TTTT.

9.3.2 Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60 Subpart TTTTa *(proposed)*.

In May 2023, the U.S. EPA proposed revised new source performance standards (NSPS) for GHG emissions from new fossil fuel-fired stationary CT EGUs. Upon promulgation of 40 CFR part 60, subpart TTTTa, stationary CTs that commence construction or reconstruction after May 23, 2023 and meet the relevant applicability criteria will be subject to 40 CFR part 60, subpart TTTTa. For new and reconstructed fossil fuel-fired CTs, EPA is proposing to create three subcategories based on the function the CT serves:

1. Low load (peaking units) subcategory that consists of CTs with a capacity factor less than 20%;
2. Intermediate load subcategory for CTs with a capacity factor that ranges between 20 percent

and a source-specific upper bound that is based on the design efficiency of the CT;

3. Base load subcategory for CTs that operate above the upper-bound threshold for intermediate load turbines.

For the low load subcategory, EPA is proposing that the best system of emissions reduction (BSER) is the use of lower emitting fuels (e.g., natural gas and distillate oil) with standards of performance ranging from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on the type of fuel combusted. With this application, APS is proposing to limit the heat input to each CT to less than 20% capacity factor.[12]

9.4 BACT Control Technology Determinations.

Table 9-2 is a summary of BACT determinations from the U.S. EPA's RACT/BACT/LAER Clearinghouse. Also included in Table 9-2 is the Ocotillo Power Plant. Emission limits range from 1,260 to 1,707 lb/MWh, and also include limits of 117 and 120 lb/mmBtu, reflecting natural gas as the fuel.

TABLE 9-2. Recent GHG BACT limits for natural gas-fired simple-cycle gas turbines.

Facility	State	Permit Date	Limit	Units	Averaging Period
TVA - Johnsonville CT	TN	Mar-23	120	lb/mmBtu	
Colbert CT Plant	AL	Mar-22	120	lb/mmBtu	
Ector County Energy	TX	Sep-21	1,514	lb CO_2/MWhr	
Washington Parish Energy	LA	Jun-21	120	lb/mmBtu	Annual Ave
Cove Point LNG Terminal	MD	May-18	117	lb/mmBtu	
Mustang Station	TX	Apr-18	120	lb/mmBtu	
Gaines County Power Plant	TX	Jun-17	1,300	lb CO_2/MWhr	
Neches Station	TX	Jul-16	1,341	lb CO_2/MWhr	
Lauderdale Plant	FL	Jul-16	1,372	lb CO_2/MWhr	12-month
Fort Myers Plant	FL	Jul-16	1,374	lb CO_2/MWhr	365 day
Perryman Generating Station	MD	Jul-16	1,394	lb CO_2/MWhr	12-month
Hill County Gen. Facility	TX	Jul-16	1,434	lb CO_2/MWhr	
Troutdale Energy Center	OR	May-16	1,707	lb CO_2/MWhr(g)	12-month
Ocotillo Power Plant	AZ	Mar-16	1,460	lb CO_2/MWhr(g)	12-month
LADWP Scattergood Station	CA	Jan-13	1,260	lb CO_2e/MWhr(n)	12-month
Pio Pico Energy Center	CA	Nov-12	1,328	lb CO_2/MWhr(g)	720 hours

[12] APS reserves the right to request a different limit should the subcategories promulgated in the final rule differ materially from the proposed subcategories.

9.5 STEP 1. Identify All Potential Control Technologies.

The first step in a top-down BACT analysis is to identify all "available" control options. Available control options are those control technologies or techniques with a practical potential for application to the emissions unit and pollutant being evaluated. Air pollution control technologies and techniques include the application of production process or available methods, systems, controls, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for the affected pollutant.

Recent BACT emission limits have been expressed on a pound per MWh of electric output basis (either gross or net output) and/or a fuel composition (pounds of GHG emissions per million Btu of heat input) basis. The averaging periods for these emission limits are typically long term, 12-month limits. The available technologies for the control of CO_2 emissions from recently permitted simple cycle natural gas-fired gas turbines identified in this database includes the use of low carbon containing fuels and the use of energy efficient processes.

CO_2 emissions result from the oxidation of carbon in the fuel. When combusting natural gas, this reaction is responsible for much of the heat released in the combustion turbine and is therefore unavoidable. Broadly, there are four potential control options for reducing CO_2 emissions from these CTs:

1. **The use of low carbon containing or lower emitting primary fuels,**
2. **Good combustion, operating, and maintenance practices, including,**
   a. Steam injection,
   b. Water injection,
   c. Dry Low NO_x combustion.
3. **The use of energy efficient processes and technologies, including,**
   a. Efficient simple cycle CTs,
   b. Combined cycle CTs,
   c. Reciprocating internal combustion engine (RICE) generators,
   d. Energy storage option.
4. **Carbon capture and sequestration (CCS) as a post combustion control system.**

With respect to the use of energy efficient processes and technologies, as stated by the Bay Area Air Quality Management District in the Statement of Basis for the Russell City Energy Center, “The only effective means to reduce the amount of CO_2 generated by (a) fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant’s required power output.” Energy efficient processes and technologies include reciprocating internal combustion engines (RICE), as well as efficient simple cycle gas (combustion) turbines (CT) and combined-cycle CTs. And there are also various energy storage systems, including battery storage, liquid air energy storage (LAES), flywheel energy storage (FES), compressed air energy storage (CAES), and pumped hydroelectric storage. However, APS is proposing to install natural gas-fired simple cycle CTs to meet the specific purpose and need of the Project. The use of combined cycle CTs or other energy storage options would change the project in such a fundamental way that the requirement to use these technologies would redefine the design of the Project. As EPA noted in its guidance, *U.S. EPA, EPA-457/B-11-001, PSD and Title V Permitting Guidance for Greenhouse Gases 26 (Mar. 2011)*, page 26:

> While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

9.5.1 Use of Low Carbon Containing or Lower Emitting Primary Fuels.

EPA's guidance document "*PSD and Title V Permitting Guidance for Greenhouse Gases*" notes that because the CAA includes "clean fuels" in the definition of BACT, clean fuels which would reduce GHG emissions but do not result in the use of a different primary fuel type or a redesign of the source should be considered in the BACT analysis. Table 9-3 is a summary of the CO_2 emission rate for coal, distillate fuel oil, and natural gas. With respect to the use of lower emitting or low carbon containing "clean" fuels, APS is proposing the use of natural gas as the primary fuel for these CTs. Because natural gas is the lowest CO_2 emitting fossil fuel available for this Project, further evaluation of clean fuels is not necessary.

TABLE 9-3. Potential CO_2 emissions for various fossil fuels.

Fuel	CO_2 Emission Rate, lb/mmBtu
Bituminous Coal	205.9
Subbituminous Coal	213.9
Distillate Fuel Oil	162.7
Natural Gas	116.9

Footnotes

The CO_2 emission rates are from *Mandatory Greenhouse Gas Reporting Requirements* 40 CFR Part 98.

9.5.1.1 Hydrogen Fuel.

In the preamble to the U.S. EPA's proposed *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*, 40 CFR 60 Subpart TTTTa, the EPA noted that the combustion of hydrogen (H_2) as a fuel in CTs would produce essentially zero direct CO_2 emissions, and EPA evaluated a number of cofiring scenarios for baseload electric generating units in the proposed rule. However, EPA also noted in the preamble that the manufacture of hydrogen can generate GHG emissions. And EPA did not propose cofiring of hydrogen for low load peaking units such as these proposed CTs.

There are a number of complications to firing hydrogen in combustion turbines. As EPA stated in the Technical Support Document (TSD) *Hydrogen in Combustion Turbine Electric Generating Units*[13] "Perhaps the most significant challenge is that the flame speed of hydrogen gas is an order of magnitude higher than that of methane; at hydrogen blends of 70 percent or greater, the flame speed is essentially tripled compared to pure natural gas. A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components as well as increase thermal NO_x emissions."

Hydrogen production methods include gasification of coal, steam methane reforming, methane pyrolysis, and electrolysis of water, as well as hydrogen derived from biomass or refuse. Without carbon capture and sequestration, producing hydrogen from coal and natural gas will itself produce GHG emissions. Production by electrolysis would have essentially zero GHG emissions, but it requires electricity to electrolyze water into hydrogen and oxygen. According to the same EPA TSD, "Specific to the electricity source, electrolysis production prices are estimated to be \$5.58/kg, \$5.96/kg, and approximately \$9.00/kg for nuclear, wind, and solar electrolysis, respectively." At a higher heating value of 61,100 Btu/lb, this is equal to costs of \$42 to \$67 per million Btu of heat input. This is more than 10 times the current cost of natural gas.

While the proposed GE LM6000PC CTs are capable of cofiring up to 35% hydrogen, there is no source of hydrogen currently available for use in these CTs. The use of hydrogen as a fuel in these CTs would fundamentally change the proposed project. As EPA notes in its GHG BACT guidance, *U.S. EPA, EPA-457/B-11-001, PSD and Title V Permitting Guidance for Greenhouse Gases 26 (Mar. 2011)*, page 26:

> While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.
>
> In assessing whether an option would fundamentally redefine a proposed source, EPA recommends that permitting authorities apply the analytical framework recently articulated by the Environmental Appeals Board. Under this framework, a permitting authority should look first at the administrative record to see how the applicant defined its goal, objectives, purpose or basic design for the proposed facility in its application. The underlying record will be an essential component of a supportable BACT determination that a proposed control technology redefines the source.

Because the use of hydrogen as a fuel would fundamentally redefine the nature of the Project as stated in this application, hydrogen fuel may be eliminated in Step 1 because the required use of hydrogen as a fuel which is not available at the Redhawk Power Plant would constitute a redefinition of the source.

[13] *Hydrogen in Combustion Turbine Electric Generating Units*, Technical Support Document, Docket ID No. EPA-HQ-OAR-2023-0072, U.S. EPA Office of Air and Radiation, May 23, 2023.

9.5.2 Good Combustion, Operating, and Maintenance Practices.

Combustion turbines may use different combustion technologies to enhance performance or reduce emissions. Combustion technologies for CTs include diffusion flame combustion with water injection, diffusion flame combustion with steam injection, and lean premix combustion using dry low NO_x combustion.

9.5.2.1 Steam Injection.

GE does not offer the proposed LM6000PC CTs with steam injection. Therefore, steam injection is not an available control option for the proposed CTs and is therefore eliminated as a control technology option.

9.5.2.2 Water Injection.

Good combustion practices including the use of water injection is an effective method for controlling NO_x emissions from these CTs. Water injection is the most widely used combustion control technology for aero derivative CTs and CTs with capacities less than 100 MW. The injection of water directly into the turbine combustor lowers the peak flame temperature and reduces thermal NO_x formation.

A significant advantage of water injection for these simple cycle CTs is the ability to achieve higher peak power output levels with water injection. The use of water injection increases the mass flow through the turbine which increases power output, especially at high ambient temperatures when peak power is often needed from these CTs. This is especially important for these CTs because the Redhawk Power Plant is located in Arizona, a region with high ambient temperatures.

9.5.2.3 Dry Low NO_x Combustion.

Dry Low NO_x (DLN) combustion is available for the LM6000PC CTs and under certain operating conditions can achieve the same NO_x emission rate as water injection, equal to a CT exhaust prior to the SCR systems of 25 ppmdv at 15% O_2. However, DLN equipped LM6000PC CTs have a lower peak electric generating capacity than the water injected units. This reduction in peak generating and ramping capacity directly affects the ability of the project to meet its basic design requirements, another reason to eliminate DLN combustion in Step 1.

In addition the DLE 1.5 technology can only achieve CT exhaust NOx emission rates of less than 25 ppm NOx emissions at 75% to 100% load. Therefore, while water injected LM6000PC CTs can achieve the NO_x emission rate of 25 ppm continuously down to 50% of load, the DLN equipped units cannot achieve this NO_x emission rate at loads below 75% of load. Because a CT turndown to 50% load is a major design criterion for the Project, utilizing DLN would require changing the basic purpose and design of the facility, and is therefore properly eliminated in Step 1 as redefining the source. In addition, the lack of turndown capability for the DLN equipped CTs makes the DLN equipped CTs technically infeasible for these peaking units.

9.5.3 Use of Energy Efficient Processes and Technologies.

The following section discusses combined cycle CTs, reciprocating internal combustion engine (RICE) electric generating units, and various energy storage technologies. However, these technologies are not control technologies. The use of combined cycle CTs, RICE electric generating units, and energy storage options would change the project in such a fundamental way that the requirement to use these technologies would redefine the design of the Project.

9.5.3.1 Combined Cycle CTs.

The use of combined cycle CTs would change the project in such a fundamental way that the plant could not meet its stated purpose of a peaking power plant. As noted above, EPA states in its GHG BACT guidance, *U.S. EPA, EPA-457/B-11-001, PSD and Title V Permitting Guidance for Greenhouse Gases (Mar. 2011)* that while Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

The Redhawk CT Expansion Project is being proposed to provide quick start and power ramping capability to meet changing and peak power demands and mitigate grid instability caused in part by the intermittency of renewable energy generation. Electric utilities primarily use simple-cycle CTs as peaking units, while combined cycle CTs are installed to provide baseload capacity. The proposed CTs can provide an electric power ramp rate equal to 50 MW per minute per CT which is critical for the project to meet its purpose and need. When all eight (8) CTs are operating at 50% load, the entire project can provide approximately 190 MW of capacity in about one (1) minute. Combined cycle units cannot provide this very fast response time which is a critical design requirement of this Project.

Combined cycle CTs are also unable to respond rapidly to the large swings in generation which can be caused by a sudden drop in generation from renewable energy sources. The long startup time for combined cycle CTs is incompatible with the purpose of the Project which is to provide quick response to changes in the supply and demand of electricity. And of critical importance is the fact that these simple cycle CTs may be required to startup and shutdown multiple times per day. These design requirements make combined cycle CTs technically infeasible for the Project. This conclusion is consistent with the U.S. EPA Region 9 evaluation and conclusion regarding the technical feasibility of combined cycle CTs for the Ocotillo Power Plant and also for the Pio Pico Energy Center. This conclusion is also consistent with the U.S. EPA Region 4 conclusion regarding the use of combined cycle units at the EFS Shady Hills Project in which EPA stated, "Based on the short startup and shutdown periods the simple cycle combustion turbines (SCCTs) offer, along with the purpose of the Project, CCCTs were considered a redefinition of the source and therefore, not considered in the BACT analysis."

Combined cycle CTs have other technical problems which also make them infeasible for this Project. When a combined cycle CT is started from a full stop as is typical for a peaking unit, the CT is simply operating in the simple cycle mode. The large frame CTs often used in combined cycle applications do not have the high turndown ratio that can be achieved with aero-derivative CTs like the LM6000PC CTs. Large frame

CTs also have longer startup times. Therefore, constructing a combined cycle CT and then operating the combined cycle unit as a peaking unit to meet the fast load response required for this Project would mean that the combined cycle CTs would operate primarily in the simple cycle mode and would result in more GHG emissions than properly constructing the plant using the proposed simple cycle CTs.

Even a fast-start combined cycle CT is only capable of achieving startup within 30 minutes if the unit is already hot. If the unit is not hot, the combined cycle CT may require more than 3 hours to achieve full load under some conditions. These longer startup times are incompatible with the purpose and need of the proposed Project which is to provide a rapid electric power response to changes in the supply and demand of electricity. To keep the heat recovery steam generator (HRSG) and the steam turbine at a sufficiently high temperature to allow for quick startup, the facility would either have to operate continuously (and therefore it would no longer be a peaking facility) or it would have to operate an auxiliary boiler. The auxiliary boiler would need to be operated even when the peaking unit is not in service to keep the unit in hot standby, resulting in additional emissions of GHGs and other pollutants.

For the above reasons, combined cycle CTs may be eliminated in Step 1 because, as EPA stated in the EFS Shady Hills Project, combined cycle CTs would not meet the basic purpose and need of the Redhawk Generating Station Combustion Turbine Expansion Project and would therefore constitute a redefinition of the source.

9.5.3.2 Reciprocating Internal Combustion Engine (RICE) Generators.

If the largest available RICE electric generating units of approximately 19 MW were used for this project, this power plant would need to construct and operate at least twenty one (21) RICE engines. This would be a more complex power plant to construct and operate. While RICE electric generating units are not a control technology, RICE are further evaluated in Step 2 of the BACT analysis.

9.5.3.3 Energy Storage Options.

A number of energy storage technologies may be available including batteries, compressed air energy storage (CAES), liquid air energy storage (LAES), pumped hydro, and flywheels. When considering energy storage options as a GHG emissions control technology in Step 1 of this analysis, it is important to point out that energy *storage* options are fundamentally different than the energy *generation* project being proposed by APS. In short, incorporating energy storage into the proposed Project is not an available control option because these options would fundamentally redefine the source.

In the U.S. EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[14] issued for a peaking facility to be comprised of reciprocating internal combustion engines (RICE), EPA determined that "energy storage cannot be required in the Step 1 BACT analysis as a matter of law." And in the U.S. EPA Environmental Appeals Board (EAB) decision regarding the APS Ocotillo Power Plant in 2016, the EAB concluded that replacing part or all of the proposed electric

---

[14] *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions, PSD-TX-1322-GHG (Nov. 2014), http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-resp2sierra-club.pdfNov%2014 .

power generation with energy storage fundamentally changed the project design and therefore the permitting authority did not err in not considering energy storage as an available technology, stating[15]:

> In sum, Maricopa County's characterization of Ocotillo's project purpose and inherent design is consistent with the record materials, and its BACT analysis incorporated a "hard look" at Arizona Public Service's business purpose. Accordingly, Maricopa County did not abuse its discretion in concluding that pairing energy storage with the proposed combustion turbines at the Ocotillo facility would "redefine the source."

Like the purpose of the Redhawk Expansion Project, the purpose of the Ocotillo Modernization Project and the Red Gate Project were to provide power for renewables and transmission grid support. EPA determined that "energy storage first requires separate generation and the transfer of the energy to storage to be effective . . . [it] is a fundamentally different design than a RICE resource that does not depend upon any other generation source to put energy on the grid." *Id.* Energy storage could not meet that production purpose for the duration or scale needed. *Id.* at 2-3. As EPA correctly observed, "[t]he nature of energy storage and the requirement to replenish that storage with another resource goes against the fundamental purpose of the facility." *Id.* at 3.

Similarly, in another PSD permit for a peaking facility for the Shady Hills Generating Station consisting of natural gas-fired simple cycle CTs (Jan 2014), EPA also concluded that energy storage would not meet the business purpose of the facility and therefore should not be considered in the BACT analysis. [16]

It is also important to note that energy storage technologies are not "zero emissions" technologies. The "round trip" energy efficiency of battery energy storage systems (BESS) is typically 80 to 90%. Other types of energy storage systems are even less. Therefore, while storage technologies may have near zero emissions at the site, the technology simply stores energy produced elsewhere, and then delivers it back to the grid, but at a net loss.

9.5.3.4 Battery Storage.

The Moss Landing Battery Storage Project is one of the largest grid connected battery energy storage facilities in the U.S. Installed at the retired Moss Landing power plant site in California, the facility has a 400 MW power output and 1,600 MWh of total energy capacity. The Redhawk Expansion Project will have a similar electric power output of almost 400 MW, and a ***continuous energy generation*** of 400 MW per hour. This means that the Moss Landing facility could provide the total energy output of the proposed Redhawk Project for a maximum of 4 hours. Thus, one of the largest battery storage facilities in the U.S. could not meet the basic purpose and need of the proposed project because this storage facility cannot provide the sustained, continuous electric generating capacity required. Therefore, the battery storage option may be eliminated at Step 1 of this BACT analysis because it would not meet the business purpose

---

[15] U.S. EPA EAB PSD Appeal No. 16-01, ORDER DENYING REVIEW, September 1, 2016, page 346.

[16] Responses to Public Comments, Draft Greenhouse Gas PSD Air Permit for the Shady Hills Generating Station at 10-11 (Jan 2014), http://www.epa.gov/region04/air/permits/ghgpermits/shadyhills/ShadyHillsRTC%20_011314.pdf.

of the Project – to provide between 25 MW to 500 MW of electrical energy as needed[17] on an immediate basis, thereby redefining the source, and under Step 2 because it is not technically feasible at this time to produce up to 500 MW of electrical energy using this method.

On April 21, 2022, the U.S. EPA issued for public input a draft technical white paper on control techniques and measures that could reduce greenhouse gas (GHG) emissions from new stationary CTs entitled *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units*, April 21, 2022. This emerging technologies document discusses the successful integration of short-term storage with natural gas-fired CTs at two 50-MW peaking plants operated by Southern California Edison (SCE). In 2017, the Norwalk and Rancho Cucamonga Generating Stations began operating the world's first "Hybrid Enhanced Gas Turbine systems". The energy storage comes from co-located 10-MW/4.3-MWh lithium-ion batteries that pull excess renewable energy from the grid and then provide energy during peak demand. Note that these batteries would be capable of providing the full 10 MW of capacity for less than 26 minutes. It is also important to note that these batteries are not required under the facilities' permits for BACT.

This document states that "energy storage allows combustion turbines to minimize starts and stops and operate more continuously at optimal efficiency, both of which reduce GHG emissions." The battery storage at the two California facilities is charged by excess renewable power pulled from the grid as opposed to being charged by turbines on site. APS already has battery energy storage systems (BESS) co-located at solar energy installations. Co-locating batteries at the Redhawk facility to be charged by the CTs would increase GHG emissions from the units as compared to operation of the CTs alone because of the inherent round-trip efficiency losses for BESS.

9.5.3.5 Liquid Air Energy Storage (LAES).

Liquid air energy storage (LAES), also called cryogenic energy storage (CES), uses low temperature (cryogenic) liquids such as liquid air to store energy. This technology is being developed by Highview Power Storage in the United Kingdom. According to their website, work is now underway at Carrington; a 50MW / 300MWh plant at Trafford Energy Park near Manchester, UK. We are not aware of any commercially operating LAES facilities on the electric power output scale of the proposed Project. The "round trip" energy efficiency of LAES is expected to be 50 – 60%[18]. Therefore, like batteries, the LAES

---

[17] See the U.S. EPA's *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions PSD-TX-1322-GHG, page 7. http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-final-rtc.pdf. EPA states with respect to the use of batteries as a BACT control option, "Thus, the option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the project – to provide up 225MW of energy for necessary time periods – and it may also be eliminated at Step 2 of the BACT analysis because it does not meet the technical requirements of the project – to provide such power for multiple days."

[18] For example, the document *Liquid Air Energy Storage (LAES): Pilot Plant to Multi MW Demonstration Plant, Highview Power Storage*, LAES technology benefits include "60% efficiency in stand alone mode. Integrates well with other industrial process plant (utilizing waste heat/cold) to enhance performance e.g. 70%+" Note that the Ocotillo Power Plant does not have waste heat/cold available to achieve the higher potential efficiency.

option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project, which is to generate and provide to the grid 25 to 400 MW of electricity as needed.

9.5.3.6 Flywheel Energy Storage (FES).

Flywheel energy storage (FES) uses electric energy input to spin a flywheel and store energy in the form of rotating kinetic energy. An electric motor-generator uses electric energy to accelerate the flywheel to speed. When needed, the energy is discharged by drawing down the kinetic energy using the same motor-generator. Because FES incurs limited wear even when used repeatedly, FES are best used for low energy applications that require many cycles such as for uninterruptible power supply (UPS) applications. We are not aware of large FES systems installed to date that have the power output or energy storage comparable to the Redhawk Expansion Project. Therefore, like batteries and LAES, the flywheel energy storage option has not been developed on a scale similar to the Project and may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project.

9.5.3.7 Compressed Air Energy Storage (CAES).

Compressed air energy storage (CAES) stores compressed air in suitable underground geologic structures when off-peak power is available, and the stored high-pressure air is returned to the surface to produce power when generation is needed during peak demand periods. The round trip energy efficiency of CAES is also expected to be approximately 50 – 60%.

There are two operating CAES plants in the world; a 110 MW plant in McIntosh, Alabama (1991) and a 290 MW plant in Huntorf, Germany (1978). Both plants store air underground in excavated salt caverns produced by solution mining. Other geological structures such as basalt flows may also be feasible CAES geologic formations. However, the Redhawk Power Plant does not have any suitable geological structures in the vicinity of the plant. Like the other energy storage options, the CAES option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project, and it can also be eliminated at Step 2 of the BACT analysis as technically infeasible.

9.5.3.8 Pumped Hydroelectric Storage.

Pumped hydroelectric storage projects move water between two reservoirs located at different elevations to store energy and generate electricity. When electricity demand is low, excess electric generating capacity is used to pump water from a lower reservoir to an upper reservoir. When electricity demand is high, the stored water is released from the upper reservoir to the lower reservoir through a turbine to generate electricity. Pumped storage projects have relatively high round trip efficiencies of 70 to 80%. However, there are no available water reservoirs at or near the Redhawk Power Plant, and water resources in the Phoenix area are scarce. Therefore, this technology is not an “available control option” at the Redhawk Power Plant and may be eliminated as a BACT option in Step 1 of the BACT analysis.

9.6 STEP 2. Identify Technically Feasible Control Technologies.

Step 2 of the BACT analysis involves the evaluation of the identified available control technologies to determine their technical feasibility. Generally, a control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source. In addition, the technology must be commercially available for it to be considered as a candidate for BACT.

Potential CO_2 controls for these CTs include the use of low carbon containing fuels, energy efficient processes and technologies including efficient simple cycle CTs, combined cycle CTs, reciprocating internal combustion engines (RICE), and the use of post combustion control systems, including carbon capture and sequestration (CCS).

9.6.1 Lower Emitting Primary Fuels.

EPA's guidance document "*PSD and Title V Permitting Guidance for Greenhouse Gases*" notes that because the CAA includes "clean fuels" in the definition of BACT, clean fuels which would reduce GHG emissions but do not result in the use of a different primary fuel type or a redesign of the source should be considered in the BACT analysis. Table 9-3 is a summary of the CO_2 emission rate for coal, distillate fuel oil, and natural gas. With respect to the use of lower emitting or low carbon containing "clean" fuels, APS is proposing the use of natural gas as the primary fuel for these CTs. Because natural gas is the lowest CO_2 emitting fossil fuel available for this Project, further evaluation of clean fuels is not necessary.

As noted in Step 1, because the use of hydrogen as a fuel would fundamentally redefine the nature of the Project as stated in this application, hydrogen fuel may be eliminated in Step 1 because the required use of hydrogen as a fuel which is not available at the Redhawk Power Plant would constitute a redefinition of the source.

9.6.2 Energy Efficient Processes and Technologies.

The use of energy efficient processes and technologies is a technically feasible CO_2 control option. As stated by the Bay Area Air Quality Management District in the Statement of Basis for the Russell City Energy Center, "The only effective means to reduce the amount of CO_2 generated by (a) fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output." Energy efficient processes and technologies include efficient simple cycle gas turbines, as well as reciprocating internal combustion engines (RICE), and combined-cycle gas turbines.

9.6.2.1 High Efficiency Simple Cycle Combustion Turbines.

APS is proposing to install eight (8) GE LM6000PC natural gas-fired simple cycle CTs for this Project. The LM6000PC CTs are efficient, fast start CTs which are well suited for the proposed project. The LM6000PC CTs utilize an aero derivative CT coupled to an electric generator to produce electric energy. A CT is an internal combustion engine which uses air as a working fluid to produce mechanical power and consists of an air inlet system, a compressor section, a combustion section, and a power section. The compressor section includes an air filter, noise silencer, and a multistage axial compressor. During operation, ambient air is drawn into the compressor section where it is compressed and discharged to the combustion section of the turbine where natural gas is injected into the turbine and the air/fuel mixture is ignited. Water is also injected into the combustion section of the turbine which reduces flame temperatures and reduces thermal NO_x formation. The heated air, water, and combustion gases pass through the power or expansion section of the turbine which consists of blades attached to a rotating shaft, and fixed blades or buckets. The expanding gases cause the blades and shaft to rotate. The power section of the turbine extracts energy from the hot gases. The power section of the turbine produces the power to drive both the compressor and the electric generator.

The LM6000PC CTs achieve a simple cycle thermal efficiency of approximately 40% based on the lower heating value (LHV) of natural gas.

9.6.2.2 Combined-Cycle CTs.

Combined cycle CTs are highly efficient power plants typically designed for baseload electric power generation. However, the purpose of this Project is to construct peaking power capacity. The Redhawk Expansion Project is being proposed to provide quick start and power ramping capability over the range of 25 MW to 400 MW to meet changing and peak power demands and mitigate grid instability caused in part by the intermittency of renewable energy generation. To satisfy the basic purpose of this plant, the peaking units must be able to start quickly even under “cold” start conditions, the units must be able to repeatedly start and stop as needed, and the units must be able to operate at low loads to provide power ramping capacity. The proposed LM6000PC CTs have a startup time of 10 minutes from dispatch to baseload, and also have a 5-minute fast start capability. This fast startup time is critical to the Project’s purpose and need.

These requirements for this peaking capacity make combined-cycle CTs technically infeasible for this Project because combined cycle CTs cannot meet the rapid startup and shutdown requirements for this peak power capacity. The start-up of a combined-cycle CT is normally conducted in three steps:

1. Purging of the heat recovery steam generator (HRSG),
2. Gas turbine startup, synchronization, and loading, and
3. Steam turbine speed-up, synchronization, and loading.

The third step of the startup process is dependent on the amount of time that the unit has been shut down prior to being restarted. As a result, the startup of a combined cycle CT are often classified as “cold” starts, “warm” starts, and “hot” starts.   The HRSG and steam turbine must be started carefully to avoid severe thermal stress which can cause damage to the equipment and unsafe operating conditions for plant personnel. For this reason, the startup time for a combined cycle CT is normally much longer than that of a similarly-sized simple cycle CT. Even with fast-start technology, new combined-cycle units may require more than 3 hours to achieve full load, as compared to approximately 30 minutes to full electric output for the proposed GE Model LMS100 simple cycle gas turbines.

“Fast start” combined cycle CTs are available but require significant changes in design, including the need for auxiliary boilers to keep the heat recovery steam generator (HRSG) hot, and/or provisions to decouple the CT exhaust from the HRSG for fast start operation. But even fast start capable combined cycle CTs have longer startup times than the proposed simple cycle CTs. Because the long startup time and reduced ramp rate capacity for combined cycle CTs is incompatible with the purpose of the Project, the use of combined cycle CTs is technically infeasible for the Project. This conclusion is consistent with the EPA

Region 9 determination for the Pio Pico Energy Center and the EPA Region 4 determination for the EFS Shady Hills Project peaking projects.

9.6.2.3 Reciprocating Internal Combustion Engines.

Reciprocating internal combustion engines (RICE) are well-suited for peaking applications and are technically feasible for the proposed Project. RICE are further evaluated in this control technology review.

9.6.3 Good Combustion, Operating, and Maintenance Practices.

Good combustion and operating practices are a potential control option by improving the efficiency of any combustion related generating technology, including simple cycle CTs and RICE generators. Good combustion practices include the proper maintenance and tune-up of the CTs or RICE on an annual basis, or more frequent basis, in accordance with the manufacturer's specifications.

9.6.4 Carbon Capture and Sequestration (CCS).

There are three approaches for Carbon Capture and Sequestration (CCS), including pre-combustion capture, post-combustion capture, and oxy-fuel combustion[19]. Pre-combustion capture is applicable primarily to fuel gasification plants, where solid fuel such as coal is converted into gaseous fuels. The conversion process could allow for the separation of the carbon containing gases for sequestration. Pre-combustion capture is not technically feasible for this proposed project which is based on natural gas combustion that does not require gas conversion.

Oxy-combustion is the combustion of fuels with nearly pure oxygen and recycled flue gas instead of air. The resultant flue gas is primarily carbon dioxide (CO_2) which facilitates the capture of high-purity CO_2 without the need for a post-combustion scrubber. However, oxy-fuel combustion is not commercially available for gas turbine applications.

Post-combustion CCS is theoretically applicable for CT power plants. However, in contrast to readily-available high-efficiency simple cycle CT technologies, emerging CCS technologies are not available or applicable to simple cycle CTs. Under the final *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units* in 40 CFR 60, Subpart TTTT, EPA established standards for newly constructed "base load" and "non-base load" fossil fuel-fired stationary CTs. In setting these standards, EPA stated that there is not sufficient information to determine that CCS is adequately demonstrated for base load natural-gas fired combustion turbines.[20] Further, in setting the fuel-based standard for non-base load CTs, the EPA concluded that the low capacity factors and irregular operating patterns (i.e., frequent starting and stopping and operating at part load) of non-base load units make the technical challenges associated with CCS even greater than those associated with base load units.

---

[19] Intergovernmental Panel on Climate Change (IPCC), 2005.
[20] Pre-publication version of the Clean Power Plan *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, page 527 of 768.

A post combustion CCS system involves three steps: 1) Capturing CO_2 from the emissions unit, 2) Transporting the CO_2 to a permanent geological storage site, and 3) Permanently storing the CO_2.

Before CO_2 emitted from these CTs can be sequestered, it must be captured as a relatively pure gas. CO_2 may be captured from the CT exhaust gas using adsorption, physical absorption, chemical absorption, cryogenic separation, gas membrane separation, and mineralization. Many of these methods are either still in development or are not suitable for treating CT flue gas due to the characteristics of the exhaust stream. The low concentration of CO_2 in natural gas-fired CTs adds to the challenge of CO_2 capture over coal-fired power plants. The CTs proposed for this Project are expected to contain approximately 5 to 6% CO_2 by volume in the flue gas exhaust. This concentration is much lower than coal-fired power plants, where the CO_2 concentration is typically 12 to 15%. As a result, there are a number of serious operational challenges and additional equipment which would be required for these natural gas-fired simple cycle CTs used for peaking load operation because of the highly variable exhaust gas flow and low CO_2 concentration. These challenges and additional equipment would have significant impacts on the operation of these CTs and the ability of these CTs to meet the basic project design requirements to provide peak power capacity and high ramp rates. CCS would also significantly affect the power output, efficiency, and cost of this Project.

Post-combustion carbon capture has been demonstrated on a slipstream from a combined cycle CT exhaust at NextEra Energy's (formerly owned and operated by Florida Power and Light) natural gas power plant in Bellingham, MA. This plant captures a 40 MW slipstream from a combined cycle CT, equal to about 365 short tons per day of CO_2. However, each of the proposed CTs could produce more than 650 tons of CO_2 per day, or more than 5,000 tons per day for eight (8) CTs combined. This is 14 times the size of the CO_2 capture system at the Bellingham Energy Center.

As noted in the POWER article, *Commercially Available CO_2 Capture Technology*, Dennis Johnson; Satish Reddy, PhD; and James Brown, PE, (available at www.powermag.com/coal/2064.html), Fluor Corporation has developed an amine-based post-combustion CO_2 capture technology called Econamine FG Plus (EFG+). There are more than 25 licensed plants worldwide that employ the EFG+ technology — from steam-methane reformers to CT power plants.

Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology, and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes. Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines. Therefore, MEA is the only carbon capture technology considered in this analysis.

In 2003, Fluor and British Petroleum (BP) completed a joint feasibility study that examined capturing CO_2 from eleven simple cycle CTs at BP's Central Gas Facility (CGF) gas processing plant in Alaska (Hurst & Walker, 2005; Simmonds et al., 2003). This project was not actually implemented. The absorption of CO_2 by MEA is a reversible exothermic reaction. To actually capture CO_2 using MEA, the turbine exhaust gas must be cooled to about 50 ºC (122 ºF) to improve absorption and minimize solvent loss due to evaporation. In the feasibility study for the CGF, the CT flue gas was to be cooled by a heat recovery steam generator (HRSG) to complete most of the cooling, followed by a direct contact cooler (DCC). Hurst & Walker (2005) found that the DCC alone would be insufficient for the CTs due to the high exhaust gas temperature of 480 - 500 °C (900 – 930 °F). Note that the LM6000PC CTs have exhaust gas temperatures of 750 to 840 °F. Therefore, to be able to actually capture CO_2 emissions, the exhaust gas would need to be reduced by 630 to 720 °F. The only feasible way to achieve this significant temperature reduction is to use a HRSG.

In a carbon capture system, after the MEA is loaded with CO_2 in the absorber, it would be sent to a stripper where it is heated to reverse the reaction and liberate the CO_2. In the CGF facility study, heat for this regeneration stage was to have come from the steam generated in the HRSG, with excess steam to be used to generate electricity. Unfortunately, the integration of a HRSG to the simple cycle CTs would convert the turbines from simple-cycle to combined-cycle operation. As noted above, combined cycle CTs are not technically feasible for the proposed project because of the fast startup times required for the Project. Therefore, while carbon capture with an MEA absorption process may be technically feasible for base load combined-cycle gas turbines, it is not feasible for simple-cycle non-base load CTs. Because combined-cycle CTs are not technically feasible for this Project, CCS is also not technically feasible for this Project.

As noted above, a post combustion CCS system involves three steps: 1) Capturing CO_2 from the emissions unit, 2) Transporting the CO_2 to a permanent geological storage site, and 3) Permanently storing the CO_2. With respect to the second and third steps, the Redhawk Power Plant does not have any nearby carbon sequestration sites available. According to the U.S. Geologic Survey (USGS) *Geologic Carbon Dioxide Sequestration Interactive Map*, the closest possible sites are the Eastern Great Basin north and west of the Colorado River in Nevada and in the northwest corner of Arizona, and the San Juan Basin in northwest New Mexico. The closest of these areas is more than 200 miles from the Redhawk Power Plant. And these closest areas are not necessarily available or feasible to be used for sequestration. These distances present severe technical feasibility problems to transporting and permanently sequestering more than 300,000 tons of CO_2 annually.

9.6.5 Conclusions regarding the technically feasible control options.

Table 9-4 identifies the technically feasible and technically infeasible control technologies for the control of GHG emissions from the proposed CTs based on the above analysis.

TABLE 9-4. Summary of the technical feasibility of GHG control technologies.

Control Technology	Technical Feasibility
1. The use of low carbon containing or lower emitting primary fuels.	Feasible
2. The use of energy efficient processes and technologies, including:	
a. Efficient Simple Cycle CTs	Feasible
b. Combined Cycle CTs	Infeasible
c. Reciprocating Internal Combustion Engines (RICE)	Feasible*
3. Good combustion and operating practices.	Feasible
4. Carbon Capture and Sequestration (CCS).	Infeasible

9.7 STEP 3. Rank The Technically Feasible Control Technologies.

Based on the above analysis, the following are technically feasible control technologies for the control of GHG emissions from this proposed new peak electric generating capacity:

1. The use of natural gas, an inherently low carbon fuel,
2. Efficient simple cycle CT electric generating units,
3. Good combustion and operating practices,
4. Reciprocating internal combustion engine (RICE) electric generating units.

With respect to the use of lower emitting primary fuels, both CT and RICE electric generating units may use the lowest commercially available carbon containing fuel – natural gas. Therefore, the lowest CO_2 and GHG emitting generating technology will be based on the efficiency of the technology and the applicability of the technology to the Project's Purpose and Need.

Table 9-6 includes detailed performance data for the proposed GE LM6000PC CTs. The lowest design heat rate (i.e., the highest efficiency) for these CTs at 100% load and an ambient temperature of 20 ºF is 9,397 Btu per kWh of gross electric energy output (Btu/kWh_g). One Btu is equal to 3,413 kWh; therefore, a gross heat rate of 9,397 Btu/kWh_g is equal to an electric generating efficiency of 36% and 1,105 lb CO_2/MWh_g. Please note that this efficiency is based on the *higher heating value* (HHV) of natural gas. For natural gas, the HHV is 1.109 times the LHV, or approximately 11% higher.

One large natural gas-fired lean burn RICE engine has a design heat rate as low as approximately 8,190 Btu/kWhg based on the HHV of natural gas. This heat rate is equal to an efficiency of approximately 42% (HHV) and a CO_2 emission rate of 947 lb CO_2/MWh_g. The largest natural gas-fired engine currently manufactured has a maximum continuous rating of up to 18.3 MW. However, only one manufacturer currently makes this engine – the Wärtsilä 18V50SG. Other manufacturers make smaller natural gas engines of up to approximately 10 MW in size. Therefore, to achieve the same gross electric output, the Project would require from 20 to 40 RICE electric generating units. This would be a much more complex installation and the existing Redhawk Power Plant may not have sufficient space for this many RICE generators.

Table 9-5 is a ranking of the technically feasible GHG control technologies based on the above stated ***best case design efficiencies, heat rates, and CO_2 emission rates*** for the RICE and CT electric generating units.

TABLE 9-5. Ranking of the technically feasible GHG control technologies for the turbines.

Technology	Minimum Heat Rate Btu/kWh_g	Best Case CO_2 Emission Rate lb/MWh_g
Natural Gas-Fired RICE Engines	8,190	947
Natural Gas-Fired GE LM6000PC CTs	9,397	1,105

TABLE 9-6. Performance data for the General Electric Model LM6000PC simple cycle CTs at various load and ambient air conditions.

CASE #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Ambient Dry Bulb Temperature	**°F**	20	20	20	41	41	41	73	73	73	105	105	105	115	115	115
Relative Humidity	%	60	60	60	51	51	51	37	37	37	19	19	19	9.5	9.5	9.5
CT Load, %		100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	70%	50%
Inlet Conditioning Fogging		OFF	OFF	OFF	OFF	OFF	OFF	**ON**	OFF	OFF	**ON**	OFF	OFF	**ON**	OFF	OFF
Performance																
Generator Output, Gross	**MW**	48.75	36.58	24.37	49.58	36.89	24.79	47.36	35.51	23.68	43.86	32.90	21.76	43.45	30.41	21.72
Generator Output, Gross	kW	48,749	36,584	24,375	49,575	36,890	24,788	47,357	35,511	23,679	43,860	32,899	21,758	43,445	30,412	21,723
Heat Rate, Gross (HHV)	Btu/kWh	9,397	9,994	11,339	9,506	10,027	11,310	9,587	10,138	11,507	9,689	10,425	12,011	9,703	10,642	12,071
Estimated Auxiliary Load	kW	729	643	594	736	647	594	726	635	573	729	609	539	757	632	560
Power, Net	kW	48,020	35,941	23,781	48,839	36,243	24,194	46,631	34,876	23,106	43,131	32,290	21,219	42,688	29,779	21,163
Fuel and Water Flow																
Total Heat Input, HHV	**MMBtu/hr**	458.1	365.6	276.4	471.3	369.9	280.3	454.0	360.0	272.5	424.9	343.0	261.3	421.6	323.6	262.2
Total Heat Input, LHV	MMBtu/hr	413.5	330.0	249.5	425.4	333.9	253.1	409.8	325.0	245.9	383.6	309.6	235.9	380.5	292.1	236.7
Fuel Flow	lb/hr	19,872	15,862	11,990	20,444	16,049	12,162	19,696	15,617	11,820	18,436	14,879	11,338	18,288	14,040	11,375
NOx Water Injection Flowrate	lb/hr	23,450	17,590	14,069	23,472	17,604	14,083	19,721	14,069	10,782	17,050	9,742	6,444	16,740	19,721	19,721
Fogging Water Flowrate	lb/hr							9,200			9,200			9,200		
Exhaust Parameters																
Exhaust Temperature	°F	788	730	675	840	767	718	850	806	782	863	857	826	864	861	850
Exhaust Flow	lb/hr	1,093,320	997,200	872,280	1,058,760	973,080	844,200	1,017,000	913,680	777,960	965,880	847,800	722,520	961,560	815,760	710,280
Exhaust Volume Flow	ACFM	590,467	511,484	425,823	598,206	517,009	428,337	581,980	502,846	416,620	559,427	484,982	402,776	556,988	470,813	406,459
Exhaust Volume Flow	SCFM	231,279	209,901	183,503	224,792	206,297	177,864	216,866	194,167	163,708	206,422	180,037	153,114	205,368	174,118	152,271
Stack Emissions																
Carbon Dioxide (CO_2)	lb/MMBtu	117.6	118.7	118.2	118.1	118.8	118.0	117.9	118.5	117.7	117.8	118.2	118.0	117.7	117.7	117.9
	lb/hr	53,883	43,390	32,655	55,652	43,928	33,072	53,541	42,662	32,075	50,073	40,533	30,835	49,621	38,107	30,914
	lb/MWhr(g)	1,105	1,186	1,340	1,123	1,191	1,334	1,131	1,201	1,355	1,142	1,232	1,417	1,142	1,253	1,423

Footnotes

1. Performance data is for the General Electric LM6000PC CTs, Power Factor 1.0, altitude 880 feet, and barometric pressure of 14.24 PSIA.
2. Performance data are based on the following natural gas fuel values: 23,051 Btu/lb, Higher Heating Value (HHV) and 1,005.3 Btu per standard cubic foot, HHV.
3. CO_2 emissions are for new CTs and do not represent degradation in engine efficiency due to normal operation of the engine.

9.8 STEP 4. Evaluate the Most Effective Controls.

9.8.1 Natural Gas-Fired RICE Engines.

From Table 9-5, the use of RICE electric generating units would have the lowest potential CO_2 emission rate of the technically feasible control options. At the CO_2 emission rates in Table 9-5, the use of these RICE engines may reduce CO_2 emissions by approximately 17% during normal operation. Note that this is an estimate of the potential reduction in CO_2 emissions. The use of from 20 to 40 RICE engines rather than 8 CTs may have other issues which could impact the overall efficiency of the power plant and the total CO_2 emissions.

However, while RICE engines may have a relatively small improvement in CO_2 emissions, the use of RICE engines would have other significant environmental impacts. The U.S. EPA has a long standing policy that the use of a control technology may be eliminated if the use of that technology would lead to increases in other pollutants, and that those increases would have significant adverse effects that may outweigh the benefits from the use of that technology. In the U.S. EPA's *New Source Review Workshop Manual*, page B.49, EPA states:

> One environmental impact is the trade-off between emissions of the various pollutants resulting from the application of a specific control technology. The use of certain control technologies may lead to increases in emissions of pollutants other than those the technology was designed to control. For example, the use of certain volatile organic compound (VOC) control technologies can increase nitrogen oxides (NOx) emissions. In this instance, the reviewing authority may want to give consideration to any relevant local air quality concern relative to the secondary pollutant (in this case NOx) in the region of the proposed source. For example, if the region in the example were nonattainment for NOx, a premium could be placed on the potential NOx impact. This could lead to elimination of the most stringent VOC technology (assuming it generated high quantities of NOx) in favor of one having less of an impact on ambient NOx concentrations.

The U.S. EPA's guidance document *PSD and Title V Permitting Guidance For Greenhouse Gases*, November, 2010 recommends that the environmental impact analysis of Step 4 of a GHG BACT analysis should concentrate on impacts other than the direct impacts due to emissions of the regulated pollutant in question. EPA has recognized that consideration of a wide variety of collateral environmental impacts is appropriate in Step 4, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, demand on local water resources, and emissions of other pollutants subject to NSR or pollutants not regulated under NSR such as air toxics. Where GHG control strategies affect emissions of other regulated pollutants, permitting authorities should consider the potential trade-offs of selecting particular GHG control strategies. Permitting authorities have flexibility when evaluating the trade-offs associated with decreasing one pollutant while increasing another, and the specific considerations made will depend on the facts of the specific permit at issue.

In this case, while the use of RICE engines may result in a reduction in CO_2 emissions, the use of RICE engines may result in an increase in other regulated PSD pollutants, especially VOC emissions. With respect to VOC emissions, RICE electric generating units have substantially higher VOC emission rates than CTs. Three different PSD permits for new natural gas-fired Wärtsilä 18V50SG RICE electric generating units equipped with oxidation catalysts for CO and VOC control have VOC BACT limits of 4.49 pounds per hour. These units have a rated heat input capacity of 154 mmBtu per hour and a rated capacity of 18.8 MW. The BACT emission limit for VOC emissions for these units of 4.49 lb/hr is equal to a VOC emission rate of 0.029 lb/mmBtu. On a heat input basis, this emission rate is more than 5 times as high as the proposed VOC emission limit for the CTs in this application.

The Redhawk Power Plant is located in Maricopa County which is currently designated as a moderate nonattainment area for ozone. Based on the ozone nonattainment status of the area, it is appropriate to favor the technology that reduces NO_x and VOC emissions over relatively small and potentially uncertain reductions in GHG emissions, especially when the difference in both NO_x and VOC emissions between the two technologies is significant. EPA Region 9 considered these same types of collateral environmental impacts from RICE generators in Step 4 of the Pio Pico GHG BACT analysis and concluded that it was appropriate to eliminate RICE engines because of these adverse collateral environmental impacts.

9.8.2 Carbon Capture and Sequestration.

As stated above in Step 2, CCS is not a technically feasible control option for these simple cycle CTs. However, even if the severe technical feasibility issues could somehow be resolved, CCS is not an economically feasible control technology for these CTs. In the preamble to the proposed standards of performance for GHG emissions for electric generating units, 40 CFR 60 Subpart TTTTa, the EPA stated[21]:

> The EPA is not proposing the use of CCS or hydrogen co-firing as the BSER (or as a component of the BSER) for low load combustion turbines. As described in the section discussing the second component of BSER for the intermediate load subcategory, the EPA is not proposing that CCS is the BSER for simple cycle combustion turbines based on the Agency's assessment that CCS may not be cost-effective for such combustion turbines when operated at intermediate load. This rationale applies with even greater force for low load combustion turbines. In addition, currently available post-combustion amine-based carbon capture systems require that the exhaust from a combustion turbine be cooled prior to entering the carbon capture equipment. The most energy efficient way to do this is to use a HSRG, which is an integral component of a combined cycle turbine system but is not incorporated in a simple cycle unit. For these reasons, the Agency is not proposing that CCS qualifies as the BSER for this subcategory of sources.

Regarding economic impacts, in its PSD BACT guidance EPA states[22]:

> EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power

[21] Federal Register, Vol. 88, No. 99, Tuesday, May 23, 2023, page 33286.
[22] U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases,* (Mar. 2011), page 42.

> plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.

For example, even though the U.S. EPA rejected CCS as a technically infeasible GHG emissions control technology option for the Palmdale Hybrid Power Project, the EPA evaluated the costs of CCS in its Response to Public Comments (October, 2011). (Please note that while EPA approved the permit for this facility, the project was never constructed.) The proposed Palmdale Hybrid Power Project included 520 MW natural gas-fired combined cycle units and 50 MW of solar photovoltaic systems. In the EPA's analysis, the estimated capital costs for the Project were $615 - $715 million, equal to an annualized cost of about $35 million. In comparison, the estimated annual cost for CCS for this Project is about $78 million, ***or more than twice the value of the facility's annual capital costs***. Based on these very high costs, EPA eliminated CCS as an economically infeasible control option. The EPA's decision to reject CCS based on these very high annual costs was upheld on appeal by the U.S. EPA's Environmental Appeals Board, PSD Appeal No. 11-07, decided September 17, 2012.

Like the Palmdale Project, the Redhawk Power Plant does not have any nearby carbon sequestration sites available. As noted in section 9.6.4, the closest of these areas is more than 200 miles from the Redhawk Power Plant. Therefore, even if the severe technical feasibility issues for the application of CCS to these simple cycle CTs could somehow be resolved, the use of CCS for this Project is not an economically feasible control technology option for these simple cycle CTs.

9.9 STEP 5. Proposed Greenhouse Gas BACT Determination.

Based on this control technology review, the use of efficient, natural gas-fired simple-cycle CTs combined with good combustion and maintenance practices represents BACT for the control of GHG emissions from the proposed CTs. Therefore, BACT will be achieved by the CT design and by the proper operation and maintenance of the CTs.

9.9.1 Combustion Turbine Design.

The proposed natural gas-fired General Electric Model LM6000PC aeroderivative simple cycle CTs are efficient, low CO_2 emitting CTs. The lowest design heat rate (i.e., the highest efficiency) for these CTs at 100% load and an ambient temperature of 20 °F is 9,397 Btu per kWh_g, equal to an electric efficiency of 36% and 1,105 lb CO_2/MWh_g.

9.9.2 Emission Limit.

9.9.2.1 Emission Limit Based on the Worst-Case Operation.

The BACT emission limit must be achievable at all times and across all load ranges for which these CTs are designed to operate. As stated in the Project Description, the new units need the ability to start quickly, change load quickly, and idle at low load. The latter requirement will allow the CTs to ramp very quickly when needed to respond to demand requirements which can occur for many reasons, including simply cloud cover reducing solar output. To provide this capability, the CTs will be designed to meet the BACT emission limits for NO_x, PM, PM_{10}, and $PM_{2.5}$ emissions at steady state loads as low as 25% of the maximum output capability of the CTs.

The CT efficiency decreases and the CO_2 emission rate increases as the load is decreased. In addition, the CO_2 emission rate may vary between CTs due to normal variation in the manufacturing process, and even with proper operation and maintenance, the CO_2 emission rate may increase over time due to the normal operation and wear of the CT components. Variation in turbines is expected to be about 3%, and degradation in performance due to normal wear is expected to be an additional 3%[23]. This variation and degradation in performance can result in a 6% increase above the design values in Table 9-6. From Table 9-6, these CTs have a design CO_2 emission rate of 1,423 lb/MWh_g at 50% load and an ambient condition of 115 °F. Therefore, this CO_2 emission rate may degrade to 1,510 lb/MWh_g over time. Furthermore, this rate does not consider startup and shutdown emissions when no energy is produced.

9.9.2.2 Emission Limit Based on the Expected Operation.

The operation of these CTs may vary substantially from day to day. The U.S. EPA Region 9 provided a framework for addressing the variation of turbine efficiency and resulting GHG emission rate as a function of load in their "*Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Pio Pico Energy Center*", November 2012. EPA stated that it is not possible to predict the extent of part load operation during every year for the life of the generating facility and that facilities are designed to meet a range of operating levels. Therefore, EPA stated it is inappropriate to establish a GHG

---

[23] U.S. EPA Region IX, *Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit, Pio Pico Energy Center*, PSD Permit Number SD 11-01, June 2012.

permit limit that prevents the facility from generating electricity as intended. For the Pio Pico PSD permit, EPA determined that the appropriate methodology for setting the GHG BACT emission limit was to set the final BACT limit at a level achievable during the lowest load, "worst-case" normal operating conditions. This methodology was also used to develop the GHG BACT limit for the APS Ocotillo CTs.

Table 9-7 is a summary of a typical anticipated run time operating scenario for these CTs. The run time scenario includes the heat input for up to 540 startup/shutdown events per year, and a projection of low, mid, and high CT load operation at five (5) ambient temperature conditions. The annual average CO_2 emission rate for the CTs based on this expected operation and including all periods of operation, including startup and shutdown, is 1,370 lb/MWh_g.

Note that the analysis in Table 9-7 is based on the design values for a new GE LM6000PC CT and does not represent the variation in CTs and the degradation in performance due to normal wear which can result in a 6% increase above the design values. Therefore, based on this analysis, the long term achievable CO_2 emission rate for these CTs is 1,450 lb CO_2/MWh_g.

TABLE 9-7. Expected operation and CO_2 emission rate for the GE LM6000PC CTs based on the non-degraded design heat rates.

Operation	Ambient Condition	% of Total	Heat Input	Heat Rate	Generation	CO_2 Emissions	
	°F	%	mmBtu/yr	Btu/kWh_g	MWh	ton/yr	lb/MWh_g
Startup / Shutdown			125,980			7,368	
Low Load: 50 - 74%	20	0.0%	70	11,339	6	4	1,326
Mid Load: 75 - 99%		0.0%	70	9,994	7	4	1,169
High Load: 100%		0.1%	699	9,397	74	41	1,099
Low Load: 50 - 74%	41	0.1%	699	11,310	62	41	1,323
Mid Load: 75 - 99%		1%	6,992	10,027	697	409	1,173
High Load: 100%		8%	55,937	9,506	5,884	3,272	1,112
Low Load: 50 - 74%	73	1%	6,992	11,507	608	409	1,346
Mid Load: 75 - 99%		14%	97,889	10,138	9,655	5,725	1,186
High Load: 100%		24%	167,810	9,587	17,505	9,815	1,121
Low Load: 50 - 74%	105	1%	6,992	12,011	582	409	1,405
Mid Load: 75 - 99%		23%	160,818	10,425	15,426	9,406	1,219
High Load: 100%		18%	125,858	9,689	12,990	7,361	1,133
Low Load: 50 - 74%	115	1%	5,454	12,071	452	319	1,412
Mid Load: 75 - 99%		2%	13,984	10,642	1,314	818	1,245
High Load: 100%		7%	48,945	9,703	5,044	2,863	1,135
Total, All Operation		**100%**	**825,190**		**70,307**	**48,263.7**	**1,370**

Because the GHG emission rate varies with ambient air temperatures, and because the operating load will vary not only with the time of day but also the time of year, the averaging period for the GHG BACT limit must be long enough to encompass this variability in operation. A 12-month rolling average basis is consistent with the majority of the CO_2 BACT emission limits and is also consistent with the final CO_2 emission standard under 40 CFR 60 Subpart TTTT. In the preamble to this proposed rule, EPA stated[24] "This 12-operating-month period is important due the inherent variability in power plant GHG emissions rates." EPA went on to say, "a 12-operating month rolling average explicitly accounts for variable operating conditions, allows for a more protective standard and decreased compliance burden, allows EGUs to have and use a consistent basis for calculating compliance (i.e., ensuring that 12 operating months of data would be used to calculate compliance irrespective of the number of long-term outages), and simplifies compliance for state permitting authorities". EPA Region 9 also stated in the Pio Pico response to comments that "EPA believes that annual averaging periods are appropriate for GHG limits in PSD permits because climate change occurs over a period of decades or longer, and because such averaging periods allow facilities some degree of flexibility while still being practically enforceable". For these reasons, APS believes that the operational limit should be based on a 12-month rolling average.

9.9.3 Gas Turbine Maintenance Requirements.

To achieve the proposed BACT emission limits, these CTs must be maintained properly to ensure peak performance of the turbines and ensure that good combustion and operating practices are maintained. Therefore, BACT also includes a requirement to prepare and follow a maintenance plan for each CT. Good CT maintenance practices normally include annual boroscopic inspections of the turbine, generator testing, control system inspections, and periodic fuel sampling and analysis. Good CT maintenance practices also includes major overhauls conducted as recommended by the manufacturer.

9.9.4 Proposed GHG BACT Requirements.

Because the GHG emission rate varies with ambient air temperatures, and because the operating load of the CTs will vary not only with the time of day but also the time of year, the averaging period for the GHG BACT limit must be long enough to encompass this variability. A 12-month rolling average basis is consistent with the majority of the CO_2 BACT emission limits and is also consistent with the final CO_2 emission standard under 40 CFR 60 Subpart TTTT. In the preamble to this proposed rule, EPA stated[25] "This 12-operating-month period is important due the inherent variability in power plant GHG emissions rates." EPA went on to say "a 12-operating month rolling average explicitly accounts for variable operating conditions, allows for a more protective standard and decreased compliance burden, allows EGUs to have and use a consistent basis for calculating compliance (i.e., ensuring that 12 operating months of data would be used to calculate compliance irrespective of the number of long-term outages), and simplifies compliance for state permitting authorities". For these reasons, APS believes that the GHG BACT emission limit should be based on a 12-month rolling average.

---

[24] Federal Register, Vol. 79, No. 5, January 8, 2014, page 1,481.

[25] Federal Register, Vol. 79, No. 5, January 8, 2014, page 1,481.

Based on this analysis, APS has concluded that the use of efficient simple cycle combustion turbines and the use of good combustion practices in combination with low carbon containing fuel (natural gas) represents the best available control technology (BACT) for the control of GHG emissions from the proposed GE LM6000PC simple-cycle combustion turbines. Based on this analysis, APS proposes the following limits as BACT for the control of GHG emissions from the new CTs:

1. CO_2 emissions may not exceed 1,450 lb CO_2 per MWh of gross electric output for all periods of operation, including periods of startup and shutdown, based on a 12-operating month rolling average.
2. The total heat input to each combustion turbine may not exceed 783,900 mmBtu based on a 12-operating month rolling average.
3. The permittee shall prepare and follow a Maintenance Plan for each CT.

9.10 Natural Gas Piping Systems GHG Control Technology Review.

The Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21 includes methane (CH_4) as a regulated GHG substance or pollutant. Natural gas piping components including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections can leak and result in fugitive natural gas emissions. Since natural gas consists of from 70 to almost 100% methane, leaks in the natural gas piping can result in methane emissions, and methane is a regulated greenhouse gas.

The Mandatory Greenhouse Gas Reporting Rules in 40 CFR Part 98, Subpart W include methods for estimating GHG emissions from petroleum and natural gas systems. Table 3-4 summarizes the estimated fugitive methane emissions and the equivalent GHG emissions, expressed as CO_2e, which are expected to result from a properly operated and maintained natural gas piping system for new CTs.

9.10.1 STEP 1. Identify All Potential Control Technologies.

The following technologies are available to control fugitive methane emissions from natural gas piping systems.

1. Leakless technology components,
2. Leak detection and repair (LDAR) program,
3. Alternative monitoring using remote sensing technology, and
4. Audio/visual/olfactory (AVO) monitoring program.

9.10.2 STEP 2. Identify Technically Feasible Control Technologies.

“Leakless” technologies such as bellows or seal valves can reduce fugitive natural gas emissions by eliminating valve gasket and flange leak paths. Other leak paths nevertheless do exist so that this technology does not eliminate fugitive emissions. Leakless technology components are used for highly toxic and hazardous materials but are not normally used in natural gas piping systems because of the high cost for these components and the difficulty in maintaining and repairing these components. For example, if a welded or threaded and seal welded bonnet joint valve fails, the failed component cannot be repaired without a unit shutdown, and the repair may result in additional maintenance related natural gas venting which can reduce its overall control effectiveness. Seal valves have other limitations which limit their use, including cycle life, pressure retention capability, and size limitations. Because these components are not a standard used in natural gas piping systems, the use of leakless valves is not considered a technically feasible control option for the CT Project natural gas piping systems.

Leak detection and repair (LDAR) programs, alternative monitoring using remote sensing technology, and audio/visual/olfactory (AVO) monitoring programs are technically feasible control options.

9.10.3 STEP 3. Rank the Technically Feasible Control Technologies.

Leak detection and repair (LDAR) programs using instrument monitoring are effective for identifying leaking components and is an accepted practice for limiting VOC emissions from gas processing and chemical plants. Quarterly monitoring with an instrument and a leak definition of 500 ppm is considered to have a control efficiency of 97% for valves, flanges, and connectors. Remote sensing using infrared imaging is also effective in detecting leaks, especially for components in difficult to monitor areas and is considered to be equivalent to LDAR.

Audio/visual/olfactory (AVO) monitoring is also an effective monitoring method for odorous and low vapor pressure compounds such as natural gas, especially because the observations can be substantially more frequent than for LDAR. Pipeline natural gas is purposely odorized with mercaptan for safety. As a result, natural gas leaks have a discernible odor. Larger leaks can be detected by sound and sight, either directly or as a secondary indicator such as condensation around a leaking source due to the adiabatic cooling effect of the expanding gas as it leaves the leaking component. Thus, observations for leaking valves or components can be made when plant personnel make routine walk-downs of the plant. As a result, AVO observation is an effective method for identifying and correcting leaks in natural gas systems, especially larger leaks that can result in increased emissions and potentially hazardous conditions. The Texas Commission on Environmental Quality (TCEQ) also assigns a 97% control effectiveness for AVO for odorous and low vapor pressure compounds such as natural gas.

9.10.4 STEP 4. Evaluate the Most Effective Controls.

The use of audio/visual/olfactory (AVO) monitoring is an effective monitoring method for the control of fugitive methane emissions from the natural gas piping systems. The proposed project will also utilize high quality components and materials of construction that are compatible with the service in which they are employed. This is the highest level of control available for the control of methane emissions from the piping systems. Therefore, no further evaluation is necessary.

9.10.5 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of audio/visual/olfactory (AVO) monitoring represents the Best Available Control Technology (BACT) for the control of fugitive methane emissions from the natural gas piping systems. APS proposes the following conditions as BACT:

1. The permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaks in the Project natural gas piping components.
2. AVO monitoring shall be performed in accordance with a written monitoring program.

9.11 SF_6 Insulated Electrical Equipment GHG Control Technology Review.

Under the Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21, sulfur hexafluoride (SF_6), Chemical Abstract Service (CAS) No. 2551-62-4, is also listed as regulated GHG. The new Project will include circuit breakers and switch gear for the CTs which will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, inert, and non-toxic gas. SF_6 has a very stable molecular structure and has a very high ionization energy which makes it an excellent electrical insulator. The gas is used for electrical insulation, arc suppression, and current interruption in high-voltage electrical equipment.

The electrical equipment containing SF_6 is designed not to leak, because if too much gas leaks out, the equipment may not operate correctly and could become unsafe. State-of-the-art circuit breakers are gas-tight and are designed to achieve a leak rate of less than or equal to 0.5% per year (by weight). This is the same leak rate from the U.S. EPA report, *SF_6 Leak Rates from High Voltage Circuit Breakers - EPA Investigates Potential Greenhouse Gas Emission Source*, J. Blackman, Program Manager, EPA, and M. Avery, ICF Consulting, and Z. Taylor, ICF Consulting. This is also the International Electrotechnical Commission (IEC) maximum leak rate standard.

Table 3-5 summarizes the potential SF_6 emissions for the planned equipment based on this leak rate. Note that these emissions represent less than 0.03% of the total GHG emissions from the proposed Project.

9.12 STEP 1. Identify All Potential Control Technologies.

The following technologies are available to control fugitive SF_6 emissions from electrical equipment:

1. State-of-the-art enclosed-pressure SF_6 technology with leak detection.
2. Use of a non-GHG emission dielectric material in the breakers.

9.13 STEP 2. Identify Technically Feasible Control Technologies.

State-of-the-art enclosed-pressure SF_6 technology with leak detection is an available technology used to limit fugitive SF_6 emissions.

There are no available alternative insulating material or substances as available alternatives. In the report *SF_6 Emission Reduction Partnership for Electric Power Systems, 2014 Annual Report*, U.S. EPA, March 2015, (http://www.epa.gov/electricpower-sf6/documents/SF6_AnnRep_2015_v9.pdf), EPA states "Because there is no clear alternative to SF_6, Partners reduce their greenhouse gas emissions through implementing emission reduction strategies such as detecting, repairing, and/or replacing problem equipment, as well as educating gas handlers on proper handling techniques of SF_6 gas during equipment installation, servicing, and disposal." Therefore, the use of alternative substances as dielectric materials is not considered a technically feasible control option for these circuit breakers.

9.14 STEP 3. Rank the Technically Feasible Control Technologies.

The use of state-of-the-art enclosed SF_6 technology with leak detection is the highest ranked technically feasible control technology to limit fugitive SF_6 emissions from the proposed electrical equipment.

9.15 STEP 4. Evaluate the Most Effective Controls.

The use of state-of-the-art enclosed SF_6 technology with leak detection for the control of SF_6 emissions from the proposed electrical equipment is the highest level of control available for the control of SF_6 emissions. Therefore, further evaluation is unnecessary.

9.16 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of state-of-the-art enclosed SF_6 technology with leak detection represents the Best Available Control technology (BACT) for the control of fugitive SF_6 emissions from the proposed electrical equipment. APS proposes the following conditions as BACT:

1. The Permittee shall install, operate, and maintain enclosed-pressure SF_6 circuit breakers with a maximum design annual leakage rate of 0.5% by weight.
2. The new circuit breakers shall be equipped with a leak detection system.
3. The permittee shall maintain records of the date that any leak is detected in a circuit breaker and the leak amount in weight percent.
4. The permittee shall maintain records of the date and the amount of SF_6 added to the circuit breakers.

Chapter 10. Emission Offset Requirements.

Maricopa County and the Redhawk Power Plant are classified as a marginal nonattainment area for the 8-hour ozone standard. The regulated ozone nonattainment area pollutants are NO_x and VOC. Major modifications of a major stationary source are subject to review under the permit requirements for new major sources or major modifications located in nonattainment areas in County Rule 240, Section 304 which incorporates 40 CFR §51.165(a)(1).

A major modification to a major stationary source in an ozone nonattainment area is defined as modification with a significant emissions increase and a significant net emissions increase in NO_x or VOC emissions. In accordance with 40 CFR §51.165(a)(1)(x)(A), for a marginal ozone nonattainment area, the significant threshold for both NO_x and VOC emissions is 40 tons per year. From Table 5-2, and in accordance with the proposed emission limits in Chapter 4 of this application, the proposed Project will result in significant emissions increase and a significant net emissions increase for NO_x emissions. This project is not subject to review under the NANSR program for VOC emissions.

Maricopa County may be reclassified as a serious nonattainment area in the near future. In accordance with 40 CFR §51.165(a)(1)(x)(B) and (C), for a serious ozone nonattainment area, the significant threshold for both NO_x and VOC emissions is 25 tons per year. If Maricopa County is reclassified as a serious ozone nonattainment area, this Project will still be subject to review under the NANSR program for NO_x emissions and not subject to NANSR review for VOC emissions.

10.1 Nonattainment Area Offset Requirements.

The total tonnage of increased emissions, in tons per year, resulting from a major modification that must be offset in accordance with section 173(a)(1)(A) of the Clean Air Act shall be determined by summing the difference between the allowable emissions after the modification and the actual emissions before the modification for each emissions unit. Because the actual emissions for the emissions units in this application are zero, the offset requirements are based on the potential to emit after the Project, or 60.4 tons per year.

In accordance with 40 CFR §51.165(a)(9)(ii)(B), for a marginal ozone nonattainment area, the ratio of total actual emissions reductions of VOC (and/or NO_x) to the emissions increase of VOC (and/or NO_x) shall be at least 1.15:1. In accordance with 40 CFR §51.165(a)(9)(ii)(C), for a serious ozone nonattainment area, the offset ratio is 1.2:1. Based on the proposed potential NO_x emissions limit of 59.0 tons per year for this Project, the NO_x emission offset or Emission Reduction Credit (ERC) requirements for this Project are:

Moderate Nonattainment Area:	(59.0 ton NOx/year)(1.15)	=	68 tons per year
Serious Nonattainment Area:	(59.0 ton NOx/year)(1.20)	=	71 tons per year

Section 173 of the Clean Air Act requires that any emission reductions required as a precondition of the issuance of a permit under paragraph (1) shall be federally enforceable before such permit may be issued. APS will surrender the necessary NO_x Emission Reduction Credits for this Project prior to issuance of the permit authorizing this Project.

Chapter 11. Ambient Air Quality Assessment.

A PSD air quality impact analysis has been performed for the pollutants NOx, PM_{10}, and $PM_{2.5}$. A minor-NSR modeling analysis has been performed for CO. The analyses follow all relevant EPA, Arizona Department of Environmental Quality (ADEQ), and Maricopa County air modeling guidance. Appendix B of this application presents the ambient air quality assessment modeling protocol and report.

The air quality impacts from the Project are insignificant for all pollutants and averaging intervals except for 1-hr NO_2 and 24-hr $PM_{2.5}$ impacts. For those two pollutants, cumulative NAAQS and PSD increment modeling analyses were performed that included the existing Redhawk emission units and other nearby sources. The results of the cumulative analyses demonstrate compliance with the NAAQS and PSD increments.

Additional PSD impact analyses were performed for soils and vegetation, Class II visibility, and associated growth. No adverse impacts were identified.

Class I area screening analyses were performed, which demonstrate that the Project impacts at the nearest Class I area (Superstition Wilderness area) are below the Class I Significant Impact Levels, and do not trigger Air Quality Relative Values (AQRV) analysis requirements.

Chapter 12. Compliance Statement.

Section 173(3) of the Clean Air Act requires the following permit requirement:

> (a) IN GENERAL.—The permit program required by section 172(b)(6) 70 shall provide that permits to construct and operate may be issued if—
>
> (3) the owner or operator of the proposed new or modified source has demonstrated that all major stationary sources owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in such State are subject to emission limitations and are in compliance, or on a schedule for compliance, with all applicable emission limitations and standards under this Act;

With this application, APS certifies that all major stationary sources owned or operated by Arizona Public Service in the State of Arizona are in compliance, or on a schedule for compliance, with all applicable emission limitations and standards under the Clean Air Act and as required by Maricopa County. The general certification of truth and accuracy for this permit application contained in the Maricopa County Air Quality Department's form *TITLE V PERMIT APPLICATION* and included in Appendix A of this application applies to this compliance statement.

Chapter 13. Alternatives Analysis.

Section 173(3) of the Clean Air Act requires the following permit requirement:

> (5) an analysis of alternative sites, sizes, production processes,
> and environmental control techniques for such proposed
> source demonstrates that benefits of the proposed source significantly
> outweigh the environmental and social costs imposed
> as a result of its location, construction, or modification.

This Project will result in significant emissions increase and a significant net emissions increase for NO_x emissions (but not VOC emissions). Therefore, this Project is subject to NANSR review for NO_x emissions. The following information and analysis of alternative sites, sizes, production processes, and environmental control techniques is being provided to demonstrate that benefits of the proposed Project significantly outweigh the environmental and social costs imposed as a result of the proposed location and modification of the Redhawk Power Plant.

13.1 Alternative Sites.

The Redhawk Power Plant is an existing electric power generating station which has already been constructed and has been in service for more than 20 years. This site is in a rural area and already has the necessary natural gas pipelines and electric transmission system infrastructure necessary for this Project. If this Project were constructed at a different site outside of the Maricopa County nonattainment area, the new site would require the installation of natural gas pipelines and electric transmission lines which would increase the environmental impact and social costs of this new electric power generation.

13.2 Alternate Sizes.

To avoid the applicability of the nonattainment new source review requirements for this Project at the Redhawk Power Plant, the installed capacity would need to be less than one-half of the proposed capacity. This much smaller installed capacity would not meet the electric power demands of the customers of APS and may lead to significant electric power reliability concerns in the region.

13.3 Alternative Production Processes.

A detailed analysis of the technically feasible electric power production techniques and an evaluation of the technically feasible options is included in the greenhouse gas emissions control technology review in Chapter 9 of this application. As detailed in that analysis, battery energy storage systems (BESS) and combined cycle combustion turbine electric generating units are not technically feasible alternative production processes for this proposed project. The only technically feasible alternative production process is the use of reciprocating internal combustion engine (RICE)-based electric generating units.

While the use of RICE electric generating units is a technically feasible alternative production process, the use of RICE may result in an increase in other regulated PSD pollutants, including NO_x, PM_{10}, and VOC emissions. With respect to VOC emissions, RICE electric generating units have substantially higher VOC emission rates than CTs. The Tucson Electric's Sundt Generating Station was permitted in 2018 to construct and operate ten (10) new natural gas-fired Wärtsilä 18V50SG RICE electric generating units equipped with oxidation catalysts for CO and VOC control. These units have a rated heat input capacity of 154 mmBtu per hour and a rated capacity of 18.8 MW. The BACT emission limit for VOC emissions for these units is 4.49 lb/hr, equal to a VOC emission rate of 0.029 lb/mmBtu. This emission rate is more than 5 times higher than the proposed VOC emission limit for the CTs in this application of 0.005 lb VOC/mmBtu.

The NO_x emission rate representing BACT for RICE engines equipped with selective catalytic reduction (SCR) is typically 5 to 6 ppm. For example, the air permit for Pacific Gas & Electric Company's Humboldt Bay Power Plant in Eureka, California authorized the use of 10 new Wärtsilä 18V50DF 16.3 MW lean-burn RICE generators equipped with SCR and oxidation catalysts. This permit was issued in 2009 and limits NO_x emissions to 6.0 ppmdv at 15% O_2, more than twice the emission concentration for the proposed CTs. Tucson Electric's Sundt Generating Station was permitted in 2018 and while not subject to NOx BACT requirements, the facility was permitted for 10 RICE units at a total capacity of 180 MW and a NOx emission increase of 170 tons per year. This is equal to a NO_x emission rate of 1,800 pounds per MW of capacity. Based on the emission limitations proposed in this application, these CTs will have a NO_x emission rate of 314 lb NOx per MW of installed capacity. And the City of Tallahassee - Arvah B. Hopkins Generating Station in Florida was permitted in 2020 to construct and operate 18.8 MW Wärtsilä 18V50SG RICE units. These units have NO_x emission limits of 2.55 lb/hr and 5 ppm at 15% O_2.

This Project is subject to the NANSR program because the Redhawk Power Plant is located in Maricopa County which is currently designated as a moderate nonattainment area for ozone. Even if RICE-based electric generating units could achieve the same NO_x emission rate as the proposed CTs, the significantly higher VOC emissions from RICE-based units would result in even greater environmental impacts to the ozone nonattainment area. These adverse collateral environmental impacts from the use of RICE generators eliminates this option as an alternative production process. After the elimination of RICE generators from this analysis, the proposed high efficiency simple-cycle CTs represent the only feasible production process.

13.4 Alternative Environmental Control Techniques.

A detailed NO_x control technology review is included in Chapter 7 of this application. Based on that control technology review, APS is proposing the lowest emission rate identified for any similar simple cycle combustion turbine. There are no alternative environmental control techniques available that can reduce NOx emissions below the proposed NOx emission limit which represents LAER for these proposed simple cycle combustion turbines.

13.5 Emission Offsets.

Based on the offsets analysis in Chapter 10 of this application, APS will surrender NOx emission reduction credits (ERCs) or emissions offsets at a ratio of 1.15 to 1 or 1.2 to 1 depending on the nonattainment classification of Maricopa County at the time of issuance of this permit. Offsets are emission reductions obtained from existing sources located in the vicinity of the Redhawk Power Plant which offset the emissions increase from the proposed modification and provide a net air quality benefit. The purpose for requiring offsets (or offsetting emissions decreases) is to allow an area to move towards attainment while still allowing growth.

Chapter 14. Environmental Justice.

14.1 Purpose.

The purpose of this Environmental Justice (EJ) evaluation is to identify any "*potential EJ concerns*," defined by United States Environmental Protection Agency (EPA) as "the actual or potential lack of fair treatment or meaningful involvement of minority populations, low-income populations, tribes, and indigenous peoples…[including] disproportionate impacts on minority populations, low-income populations, and/or indigenous peoples that may exist prior to or that may be created by the proposed" Redhawk Expansion Project.[26]

14.2 EPA's Definition of Environmental Justice.

The EPA defines EJ as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. An environmental justice analysis accomplishes two important policy objectives: (1) it addresses the principle of fair treatment by further evaluating adverse and disproportionate impacts and identifying ways to prevent or mitigate such impacts; and (2) it addresses the principle of meaningful involvement by fostering enhanced community engagement in the permitting decision.

14.3 Overview of EPA's Environmental Justice Guidance.

APS's evaluation and actions are generally consistent with EPA and other federal agency guidance on EJ, including:

- EPA, Environmental Justice Website (https://www.epa.gov/environmentaljustice)
- EPA, EJ in Air Permitting - Principles for Addressing Environmental Justice Concerns in Air Permitting (Dec. 22, 2022, https://www.epa.gov/caa-permitting/ej-air-permitting-principles-addressing-environmental-justice-concerns-air)
- EPA, Clean Air Power Sector Programs, Power Plants and Neighboring Communities (https://www.epa.gov/power-sector/power-plants-and-neighboring-communities)
- EPA, EJ Screen: Environmental Justice Screening and Mapping Tool, How to Interpret EJScreen Data (https://www.epa.gov/ejscreen/how-interpret-ejscreen-data#:~:text=For%20early%20applications%20of%20EJScreen,potential%20candidate%20for%20further%20review)

- Federal Interagency Working Group on Environmental Justice & NEPA Committee, Promising Practices for EJ Methodologies in NEPA Reviews (March 2016, https://www.epa.gov/sites/default/files/2016-08/documents/nepa_promising_practices_document_2016.pdf)
- EPA, EPA Activities To Promote Environmental Justice in the Permit Application Process,78 Fed. Reg. 27220, 27227 (May 9, 2013, https://www.federalregister.gov/documents/2013/05/09/2013-10945/epa-activities-to-promote-environmental-justice-in-the-permit-application-process)
- EPA, Technical Guidance for Assessing Environmental Justice in Regulatory Analysis (June 2016, https://www.epa.gov/sites/default/files/2016-06/documents/ejtg_5_6_16_v5.1.pdf)

Apart from recent guidance issued in December 2022, EPA has issued little guidance or methodologies for air permit *applicants* to follow in conducting EJ evaluations; rather, EPA's EJ guidance is largely focused on actions the *agency* must undertake to ensure a robust consideration of "potential EJ concerns." Nonetheless, EPA's suite of guidance documents provides a general framework for how air permit applicants could approach EJ analyses.

14.3.1 Step One: Define the Study Area.

EPA's guidance suggests that applicants should define a "study area" that comprises a three (3) mile radius around the project site, for EJ evaluation purposes. EJ Screening Report for the Clean Power Plan."[27]

14.3.2 Step Two: Evaluate the Study Area Utilizing EPA's EJScreen Tool.

EPA's guidance emphasizes the utilization of EPA's EJScreen tool (EJScreen).[28] EJScreen is "EPA's environmental justice mapping and screening tool that provides EPA with a nationally consistent dataset and approach for combining environmental and demographic socioeconomic indicators."[29] Users identify a defined study area within the tool and the tool then provides demographic, socioeconomic and environmental information for that area.

EJScreen provides four sets of data for the study area, including:

- Thirteen (13) Environmental Indicators;
- Thirteen (13) Environmental Index scores that combine each Environmental Indicator with two (2) demographic factors (income and people of color);
- Seven (7) Socioeconomic Indicators designed to identify disadvantaged communities; and

[27] EPA, Power Plants and Neighboring Communities (epa.gov)

[28] EPA, EJ Screening Tool (epa.gov)

[29] EPA, What Is EJScreen? (epa.gov)

- Supplemental Index score that averages five (5) Socioeconomic Indicators with the Environmental Indicator to quantify community-level vulnerabilities.

14.3.3 Step Three: Identify Potentially Adverse or Disproportionate Impacts within the Study Area.

EPA defines "disproportionate impacts" as differences in impacts or risks that are "extensive enough that they may merit Agency action." EPA further states that the higher the average differences between the potentially affected study area communities and the comparison groups (in our case, the county and state populations) the greater the potential for a disproportionate adverse impact.

EPAs guidance provides that a study area with any of the 13 EJ Index Scores at or above the 80th percentile nationally should be considered as a potential candidate for further EJ review due to potential adverse or disproportionate impacts[30]. It is important to note that exceeding this screening level does not automatically confer EJ status for a community, but rather is a starting point that identifies potential areas of concern.

14.3.4 Step Four: Ensure Meaningful Involvement of Potentially Impacted Community Members.

If a community is identified as adversely and disproportionately impacted in steps one through three, EPA's guidance instructs that these communities be afforded the opportunity for "meaningful involvement" in agency decision-making. EPA defines "meaningful involvement" as comprising four elements:

1. Potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health;
2. The population's contribution can influence EPA's decisions;
3. The concerns of all participants involved are considered in the decision-making process; and
4. EPA will seek out and facilitate the involvement of populations potentially affected by EPA's decisions.[31]

---

[30] EPA, How To Interpret EJScreen Data (epa.gov)

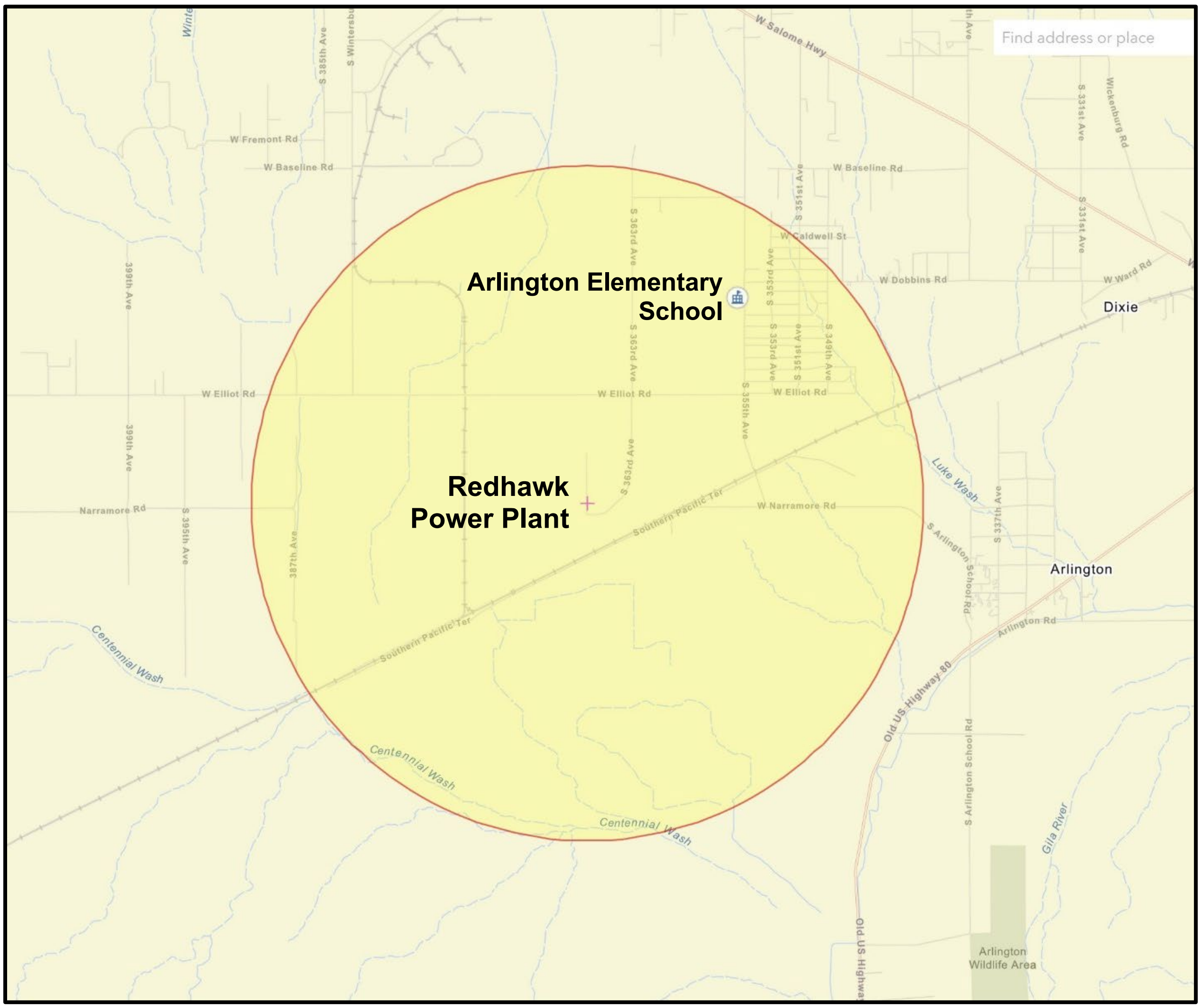
[31] EPA, Technical Guidance for Assessing Environmental Justice in Regulatory Actions (June 2016)

14.4 EJ Analysis Step One: Define the Study Area

The Redhawk Power Plant (SPP) is located at 11600 South 363rd Avenue, Arlington, Arizona, in Maricopa County. The site is located in an area designated as attainment or maintenance for all criteria air pollutants, except for the 8-hour ozone standard. The area is classified as a marginal nonattainment area for the ozone standard.

This EJ analysis utilized the U.S. EPA's recommended three-mile radius in considering the potential for adverse and disproportionate impacts. Figure 14-1 shows the study area from EJScreen.

FIGURE 14-1. Environmental Justice "Study Area" for the Redhawk Power Plant.



14.5 EJ Analysis Step Two: Evaluate the Study Area Utilizing EPA's EJScreen Tool.

It is important to note the following limitations to the data and evaluation in the following analysis. The census data used has inherent measurement of error (MOE) and in some cases may be outdated because the most recent data comes from 2021 and community profiles have likely evolved over the past two years.

14.5.1 Demographics.

There is little guidance around how to assess or value differences between the study area and the broader communities, state and nation — there are no defined thresholds for what constitutes a meaningful difference. The Federal Interagency Working Group on Environmental Justice and NEPA Committee's guidance document *Promising Practices for EJ Methodologies in NEPA Reviews* provides some insights into how to define "minority communities" and when differentials may be significant:

- A population is identified as "minority" if the minority population exceeds 50 percent of the study area; and
- A difference between the study area and the broader reference community is "meaningfully greater" if it is "ten or twenty percent greater than the reference community."[32]

In accordance with EJ guidance, this analysis will identify the study area as a "minority community" if the population is 50% or greater minority; and we flag any parameters in which the study area's demographics differ from Maricopa County or the State of Arizona by a factor of 10% or more.

For example, if a census tract classifies 35% of the population as low income but the county consists of 30% low income, the census tract would exceed the county average by 16.7% and thus be flagged as a potential area of concern. For this report, census data from the 2020 Census, American Community Survey, were used. The U.S. Census Bureau standard for the margin of error (MOE) is at the 90% confidence level. On the other hand, if a census tract indicates that 25% of the area is made up of people of color, but the county average is 35%, this element would not be flagged as a potential concern.

Table 12-1 is a summary of the EJ screening socioeconomic factors from EPA's EJScreen mapping tool. In this analysis, the **bolded and blue** data for the area within a three-mile radius of the proposed site—referred to as the "study area"—indicate a difference greater than 10% and a potential concern for the study area when compared to Maricopa County. The **bolded and orange** data indicate a difference greater than 10% and a potential concern for the study area when compared to the State of Arizona. Bolded data indicates a difference of greater than 10% but not a potential concern for the study area.

From Table 14-1, the study area has a lower percentage of individuals in all selected variables except "Less Than High School Education" and "Low Life Expectancy" as compared to both Maricopa County and the

[32]Federal Interagency Working Group on Environmental Justice and NEPA Committee, Promising Practices for EJ Methodologies in NEPA Reviews (Mar. 2016).

State of Arizona. The study area has a higher population with less than a high school education than both Maricopa County and the State of Arizona. With respect to "Low Life Expectancy", the study area has a slightly higher low life expectancy (20%) than the state as a whole (19%).

TABLE 14-1. Summary of the environmental justice screening socioeconomic factors from EJScreen.

Selected Variable	Study Area	Maricopa County	State Average	Percentile in State
Demographic Index	26%	**38%**	**38%**	37
People of Color	37%	**45%**	**44%**	47
Low Income	16%	**30%**	**32%**	28
Unemployment Rate	2%	**5%**	**6%**	35
Limited English Speaking	0%	**3%**	**4%**	0
Less Than High School Education	31%	**12%**	**12%**	90
Population under Age 5	4%	**6%**	**5%**	47
Population over Age 64	11%	**15%**	**20%**	38
Low Life Expectancy	20%		19%	59

Footnotes

Source: U.S. EPA EJScreen.

Bolded and orange data indicate a difference greater than 10% and a potential concern when compared to the state.

Bolded and blue data indicate a difference greater than 10% and a potential concern when compared to the county.

All bolded data indicate a difference greater than 10% compared to the county or state.

14.5.2 Ethnicity and Race.

14.5.2.1 Regional Setting.

Table 14-2 is a summary of the 2021 U.S. Census Bureau data for Maricopa County, the State of Arizona, and the 3-mile radius study area around the proposed site. Note that the study area has a very low population of only 217 individuals in an area of 28.27 square miles, equal to a population density of less than 8 individuals per square mile.

From Table 14-2, Arizona's population totals 7,276,316 individuals. The three most populous racial groups across the state are: White 77.6%; Hispanic or Latino (of any race) 32.3%; and Two or More Races 20.1%. Maricopa County has a total population of 4,412,779 individuals. Similar to the state as a whole, the three most common racial groups within the county are: White (73.8%); Hispanic or Latino (of any race) (31.1%); and two or more races (7.1%). In the composition of the three most populous racial groups, Maricopa County and the State of Arizona are similar.

In Table 14-2, the **bolded and orange** data indicate a difference greater than 10% and a potential concern when comparing the study area to the State of Arizona. The populations of all ethnic groups are lower as a percentage than the state as a whole except for the total Hispanic population which is 35% as compared to the state as a whole of 32.3%.

14.5.2.2 Local Setting.

The total population within the study area of the proposed site is 217 individuals. Within this area, the largest population is White at 63% and 137 individuals, followed by Hispanic of any race at 35% and 76 individuals.

In Table 14-2, the **bolded and blue** data for the study area indicate a difference greater than 10% and a potential concern when compared to Maricopa County. Like the comparison to the state as a whole, the populations of all ethnic groups are lower as a percentage than the state as a whole except for the total Hispanic population which is 35% as compared to Maricopa County at 31.1%.

TABLE 14-2. Summary of the U.S. Census Bureau data by race for Maricopa County, the State of Arizona, and the study area around the Redhawk Power Plant.

Race and Ethnicity	Study Area		Maricopa County		Arizona	
	Number	Percent	Number	Percent	Number	Percent
Total Population	217	100.0%	4,412,779	100.0%	7,276,316	100.0%
White	137	63.0%	3,256,087	**73.8%**	5,645,464	**77.6%**
Black or African American	0	0.0%	249,691	**5.7%**	326,638	**4.5%**
American Indian or Alaska Native	0	0.0%	85,061	**1.9%**	294,658	**4.0%**
Asian	0	0.0%	187,298	**4.2%**	245,285	**3.4%**
Native Hawaiian and Other Pacific Islander	0	0.0%	9696	**0.2%**	12,432	**0.2%**
Some other Race	0	0.0%	313,146	**7.1%**	693,486	**9.5%**
Two or More Races	2	1.0%	311,800	**7.1%**	1,462,148	**20.1%**
Total Hispanic Population (of any race)	76	35.0%	1,374,312	**31.1%**	2,351,124	32.3%

Footnotes

Source: U.S. EPA EJScreen.

Bolded and orange data indicate a difference greater than 10% and a potential concern when compared to the state.

Bolded and blue data indicate a difference greater than 10% and a potential concern when compared to the county.

All bolded data indicate a difference greater than 10% compared to the county or state.

14.5.3 Age and Sex.

14.5.3.1 Regional Setting.

According to the U.S. Census Bureau data summarized in Table 14-3, Arizona has a total population of 7,276,316 individuals, with almost 79% of the population older than 18 years of age, and almost 20% of the population 65 years and older. Maricopa County has a total population of 4,412,779 individuals, with 76% of the population older than 18 years of age and 15% of the population 65 years and older. Maricopa County's population is similar in age to the state as a whole, except that Maricopa County has a slightly larger percentage of the population 0 to 4 years old, and a smaller percentage of the population 65 years and older. The composition of both Maricopa County and the study area are similar to the state as a whole with respect to sex.

14.5.3.2 Local Setting.

From Table 14-3, the study area has an age distribution which is more than 10% different than both the county and the state for all age ranges. The study area is generally older than either Maricopa County or the State of Arizona, with smaller percentages of individuals 0 – 4 and 0 – 17 years of age, and more individuals greater than 18 years of age and greater than 65 years of age. With respect to sex, while the local population percentages do not vary by more than 10% from state or local populations, the local area does have a higher male population than both Maricopa County and the State of Arizona.

TABLE 14-3. Summary of the U.S. Census Bureau data by age and sex for Maricopa County, the State of Arizona, and the study area around the Redhawk Power Plant.

Age and Sex	Study Area		Maricopa County		Arizona	
	Number	Percent	Number	Percent	Number	Percent
Total Population	217	100.0%	4,412,779	100.0%	7,276,316	100.0%
Male	117	54.0%	2,181,967	49.4%	3,629,620	49.9%
Female	100	46.0%	2,230,812	50.6%	3,646,696	50.1%
Population Age 0-4	9	4.0%	277,315	**6.3%**	402,255	**5.5%**
Population Age 0-17	24	11.0%	1,051,018	**23.8%**	1,614,284	**22.2%**
Population Age 18+	193	89.0%	3,361,761	**76.2%**	5,662,032	**77.8%**
Population Age 65+	24	11.0%	671,096	**15.2%**	1,333,985	**18.3%**

Footnotes

Source: U.S. Census Bureau, American Community Survey (ACS) 2017 – 2021 (EJScreen).

Bolded and orange data indicate a difference greater than 10% and a potential concern when compared to the state.

Bolded and blue data indicate a difference greater than 10% and a potential concern when compared to the county.

All bolded data indicate a difference greater than 10% compared to the county or state.

14.5.4 Household Income and Poverty.

14.5.4.1 Regional Setting.

From the U.S. Census Bureau data in Table 14-4, the State of Arizona has an average per capita income of \$38,334, with 12.8% of the total population being low income. Maricopa County has an average per capita income of \$37,570, with 29% of the total population being low income.

14.5.4.2 Local Setting.

From Table 14-4, the study area has a total population of 217 individuals and 75 households. The data indicate an average of 2.9 persons per household, which is similar to both the state and county averages. The percentage of the population with low income in the study area is more than 10% less than Maricopa County and the State of Arizona. The per capita income in the study area is also less than both Maricopa County and the State of Arizona by more than 10%, indicating that the local population is in general poorer than the county or state averages.

TABLE 14-4. Summary of the U.S. Census Bureau household income data for the State of Arizona, Maricopa County, and the study area around the proposed site.

Income Levels	Study Area		Maricopa County		Arizona	
	Number	Percent	Number	Percent	Number	Percent
Total Population	217	100.0%	4,412,779	100.0%	7,276,316	100.0%
Low Income		16.0%		**29.0%**		**12.8%**
Unemployment Rate		2.0%		**5.0%**		**32.0%**
Number of Households	75		1,632,151		2,739,136	
Persons per Household	2.9		2.7		2.7	
Owner Occupied Housing		87.0%		**64.0%**		**66.3%**
Per Capita Income	\$33,108		**\$37,570**		**\$38,334**	

Footnotes

Source: U.S. EPA EJScreen.

Bolded and orange data indicate a difference greater than 10% and a potential concern when compared to the state.

Bolded and blue data indicate a difference greater than 10% and a potential concern when compared to the county.

All bolded data indicate a difference greater than 10% compared to the county or state.

14.5.5 Limited English Proficiency.

14.5.5.1 Regional Setting.

From Table 14-5, 74% of the households in Maricopa County speak English at home, and 3% of the households had limited English proficiency. For the State of Arizona, 74% of the households speak English at home, and a slightly higher percentage of 4% of the households had limited English proficiency. For both Maricopa County and the State of Arizona, 20% of the households have Spanish spoken at home.

14.5.5.2 Local Setting.

As set forth in Table 14-5, of the 217 individuals and 75 households in the study area, none of the households have limited English proficiency or speak another language at home. Thus, the study area appears to have a very high English proficiency.

TABLE 14-5. Summary of the U.S. Census Bureau English proficiency data for Maricopa County and the study area.

English Proficiency Levels	Study Area		Maricopa County		Arizona	
	Number	Percent	Number	Percent	Number	Percent
Number of Households	75		1,632,151		2,739,136	
Limited English Households		0.0%		**3.0%**		**4.0%**
English Spoken at Home				**74.0%**		**73.8%**
Spanish Spoken at Home		0.0%		**20.0%**		**19.8%**
Other Asian and Pacific Island		0.0%		**1.0%**		**2.2%**
Other Indo-European		0.0%		**1.0%**		**1.9%**
Other and Unspecified		0.0%		**1.0%**		**2.3%**
Total Non-English		0.0%		**26.0%**		**26.0%**

Footnotes

Source: U.S. EPA EJScreen.

Bolded and orange data indicate a difference greater than 10% and a potential concern when compared to the state.

Bolded and blue data indicate a difference greater than 10% and a potential concern when compared to the county.

All bolded data indicate a difference greater than 10% compared to the county or state.

14.5.6 Health.

The University of Wisconsin Population Health Institute, in collaboration with the Robert Wood Johnson Foundation, maintains a County Health Rankings system for all states in the United States. These rankings measures two elements: "Health Outcomes" and "Health Factors."[33]

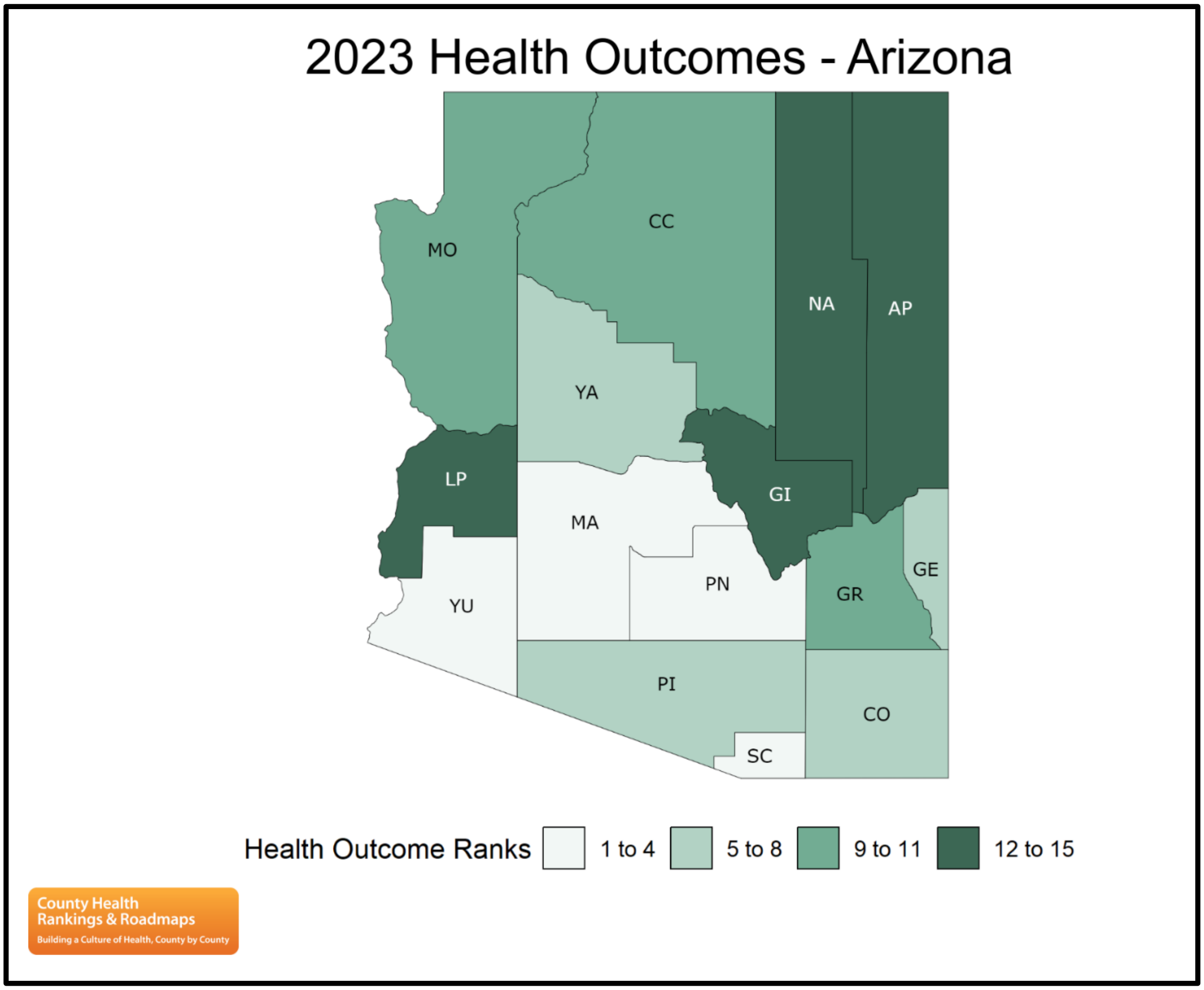
The "Health Outcomes" data represent the *current* health of a county's residents, in terms of length and quality of life. They reflect the physical and mental well-being of residents through measures representing the length and quality of life typically experienced in the community. Maricopa County ranks 1st out of 15 Arizona counties for Health Outcomes. Figure 14-2 shows the 2023 Health Outcomes ranks for the counties in Arizona.

The "Health Factors" data represent those things that can be modified to improve the length and quality of life for residents; they are predictors of how healthy a community may become in the future. The four Health Factors considered in the model include Health Behaviors, Clinical Care, Social & Economic Factors, and Physical Environment. Maricopa County ranks 3rd out of 15 Arizona counties for Health Factors. Figure 14-3 shows the 2023 Health Factors ranks for the counties in Arizona.

These data indicate that residents in Maricopa County enjoy better Health Outcomes than residents in other Arizona counties and have good opportunities to continue to improve Health Factors that can extend and enhance the quality of life.

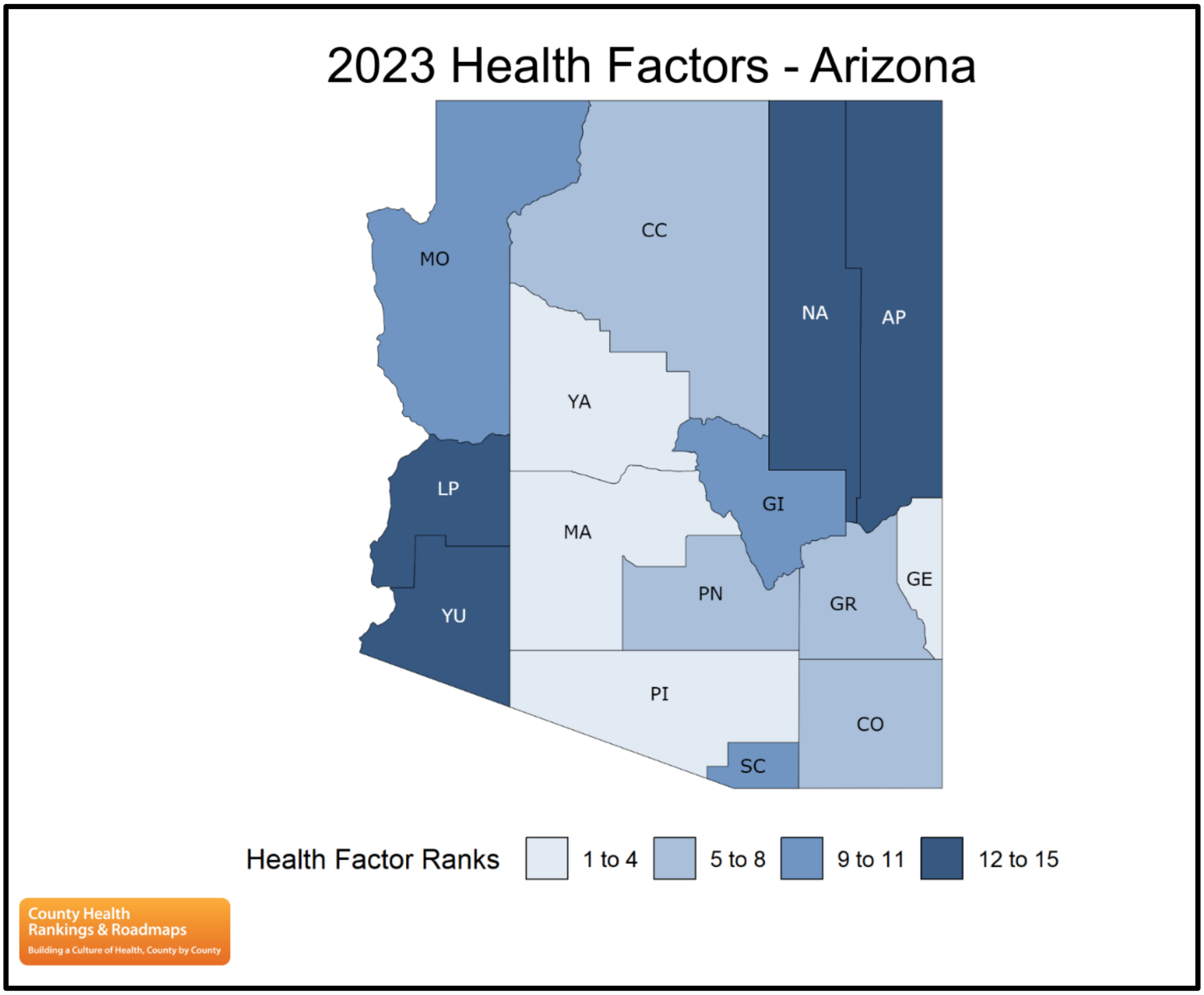
[33] University of Wisconsin Population Health Institute | County Health Rankings

FIGURE 14-2. Year 2023 Health Outcome ranks for Arizona counties.



Source: University of Wisconsin Population Health Institute and the Robert Wood Johnson Foundation, available at https://www.countyhealthrankings.org/explore-health-rankings/arizona/data-and-resources.

FIGURE 14-3. Year 2023 Health Factors ranks Arizona counties.



Source: University of Wisconsin Population Health Institute and the Robert Wood Johnson Foundation, available at https://www.countyhealthrankings.org/explore-health-rankings/arizona/data-and-resources.

14.5.7 Environmental Indicators.

The EPA EJScreen tool was used to evaluate the Environmental Indicators and the Environmental Indices for the study area. The Environmental Indicators quantify proximity to and the numbers of certain types of potential sources of exposure to environmental pollutants. EJScreen calculates the Environmental Index by using the Environmental Indicator percentile for a block group, as defined by the U.S. Census Bureau, multiplied by the Demographic Index for the block group. The EPA EJScreen Demographic Index refers to people within the socioeconomic groups outlined in Table 14-1. Per the screening guidance[34], any Environmental Indicator over the 80th percentile is a candidate for further review. The following EJ indicators were evaluated for the study area:

- Particulate Matter 2.5
- Ozone
- Diesel Particulate Matter
- Air Toxics Cancer Risks
- Air Toxics Respiratory Hazard Index
- Toxic Releases to Air
- Traffic Proximity
- Lead Paint
- Superfund Proximity
- RMP Facility Proximity
- Hazardous Waste Proximity
- Underground Storage Tanks
- Wastewater Discharge

Table 14-6 summarizes the EJ indicators from EJScreen which were evaluated for the study area. From Table 14-6, only Superfund Proximity, i.e., the site count/km distance, exceeded the 80th percentile.

[34] U.S. EPA, EJScreen Tool | US EPA

TABLE 14-6. Pollution and Sources Environmental Indicators from EJScreen.

Selected Variable	Study Area	State Average	Percentile in State	National Average	Percentile in Nation
Particulate Matter < 2.5µm (µg/m^3)	5.83	5.87	42%	8.08	7%
Ozone (ppb)	59.2	66.1	3%	61.6	33%
Diesel Particulate Matter (µg/m^3)	0.0813	0.278	16%	0.261	<50th
Air Toxics Cancer Risk* (lifetime risk per million)	20	25	13%	25	<50th
Air Toxics Respiratory Hazard Index*	0.23	0.31	10%	0.31	<50th
Toxic Releases to Air	140	2800	24%	4600	27%
Traffic Proximity (daily traffic count/distance to road)	2.7	190	3%	210	8%
Lead Paint (% Pre-1960 Housing)	0.0016	0.089	0%	0.3	0%
Superfund Proximity (site count/km distance)	0.11	0.077	**84%**	0.13	69%
RMP Facility Proximity (facility count/km distance)	0.15	0.38	50%	0.43	44%
Hazardous Waste Proximity (facility count/km distance)	0.021	0.71	5%	1.9	2%
Underground Storage Tanks (count/km^2)	0.018	1.7	31%	3.9	23%
Wastewater Discharge (toxicity-weighted concentration/m distance)	0.27	5.8	66%	22	**87%**

Footnotes

Source: EPA, EJ Screening Tool 2.2

All bolded data indicate a potential concern.

Particulate Matter 2.5 ($PM_{2.5}$). EPA defines particulate matter as solid particles and liquid droplets found in the air.[35] Particulate matter 2.5 ($PM_{2.5}$) comprises inhalable particles with a diameter less than 2.5 micrometers. According to EPA's EJScreen tool, $PM_{2.5}$ measures 5.83 µg/m^3 within the study area around the plant. In comparison, the average $PM_{2.5}$ value for the State of Arizona is 5.87 µg/m^3; the average $PM_{2.5}$ value across the nation is 8.08 µg/m^3. The study area is at the 42nd percentile for the state (slightly better than average) and the 7th percentile for the nation (significantly better). For the $PM_{2.5}$ EJ Index, the study area is at the 45th percentile for the state and the 12th percentile for the nation, meaning the $PM_{2.5}$ air quality for people within the study area is slightly better compared to the rest of the state and much better (i.e., lower) than the average compared to the nation.

Ozone. The ozone (O_3) variable refers to the average annual top 10 daily maximum 8-hour concentrations of ozone in the air. The study area has a value of 59.2 parts per billion (ppb) for ozone. In comparison, the average value for the state is 66.1 ppb, and the average value nationally is 61.6 ppb. The study area is at the 42nd percentile for the state and 33rd percentile for the nation, meaning the ozone exposure in the study area is lower than the average in the state and also lower than the average in the country. For the ozone EJ Index, the study area is at the 5th percentile for the state and the 43rd percentile for the nation, meaning that the ozone exposure to people within the study area much lower than the rest of the state and slightly lower than the rest of the country.

Diesel Particulate Matter (PM). The Diesel PM variable describes the amount of diesel particulate matter in the air. The study area has a value of 0.0813 µg/m^3; the average value for the state is 0.278 µg/m^3; and the average value for the nation is 0.261 µg/m^3. The study area is in the 16th percentile for the state and is less than the 50th percentile for the nation, meaning there is less diesel PM in the air compared to both the state and the country. For the Diesel Particulate Matter EJ Index, the study area is at the 21st percentile for both the state and the nation, meaning that exposure to diesel particulate matter is below both the state and national averages.

Air Toxics Cancer Risk. The Air Toxics Cancer Risk variable refers to the lifetime cancer risk from inhaling toxic air contaminants. The study area has a value of 20 for the Air Toxics Cancer Risk variable, measured as a lifetime risk per one million population. In comparison, the average state value is 25, and the average national value is also 25. The study area is in the 13th percentile for the state and less than the 50th percentile for the nation, meaning that the risk for getting cancer from inhaling toxic air contaminants is lower in the study area than in both the state and the country. For the Air Toxics Cancer Risk EJ Index, the study area is at the 25th percentile for the state and the 30th percentile for the nation. This also indicates that the risk of getting cancer from inhaling toxic air contaminants by people within the study area is lower than the rest of the state and is also less than the average of the country.

Air Toxics Respiratory Hazard Index. The Air Toxics Respiratory Hazard Index (HI) measures the ratio of exposure concentrations of toxics in the air to the health-based reference concentrations set by EPA. The study area has a value of 0.23 (unitless index) for the Air Toxics HI variable. In comparison, the average

[35] Environmental Protection Agency | EPA Particulate Matter PM Basics

value for the state is 0.31, and the average value nationally is also 0.31. The study area is at the 10th percentile for the state and less than the 50th percentile nationally, meaning that exposure to high concentrations of air toxins is lower in the study area compared to the state and nation. For the Air Toxics Respiratory HI EJ Index, the study area is at the 30th percentile for the state and the 37th percentile for the nation, indicating that air toxics exposure is less than the state and national averages.

Toxic Releases to Air. The Toxics Releases to Air indicator quantifies relative potential human health impacts of certain chemicals included on the list of toxic chemicals from the Emergency Planning and Community Right-to-Know Act (EPCRA), based on the amount released by facilities. The study area has a value of 140 (unitless score) for the Toxic Releases to Air score. In comparison, the average score for the state is 2,800, and the average score nationally is 4,600. The study area is at the 24th percentile for the state and the 27th percentile nationally, meaning there are significantly fewer toxic releases to the ambient air in the study area than in both the state and the nation. For the Toxic Releases to Air EJ Index, the study area is at the 30th percentile for the State and the 29th percentile nationally, meaning toxic chemical releases are lower in the study area than both the state and national averages.

Traffic Proximity. The Traffic Proximity indicator quantifies the volume of vehicles at major roads within 500 meters divided by the distance to the road. The study area has a value of 2.7 (unitless score) for Traffic Proximity. In comparison, the average score for the state is 190, and the average score nationally is 210. The study area is at the 3rd percentile for the state and the 8th percentile nationally, meaning there are significantly fewer vehicles within 500 meters in the study area than both the state and the nation. For the Traffic Proximity EJ Index, the study area is at the 5th percentile for the state and the 12th percentile nationally, meaning the exposure within the EPA EJScreen demographic index to traffic is much lower than the average for both state and the country.

Lead Paint (% Pre-1960 Housing). The lead paint indicator is simply the percentage of occupied housing units built before 1960. This is a surrogate for the potential prevalence of lead paint. The study area has a value of 0.0016% Lead Paint %. In comparison the average score for the state is 0.089% which puts the study area value in the zero percentile for the state. The national average lead paint indicator value is 0.3% for nation, also placing the study area in the zero percentile nationally. The study area has a significantly less potential lead paint exposure than both the state and nation. The study area also has an EJ Index for Lead Paint in the zero percentile as compared to the state and nation.

Superfund Proximity. The Superfund proximity indicator is reflective of the total count of sites proposed and listed (final) on the National Priorities List (NPL). This is calculated by assigning distance-weighted scores for those NPL sites within 5 km. The value for the study area is 0.11 sites/km distance. The state average score is 0.077 which places the study area in the 84th percentile for the state. The national Superfund proximity indicator score is 0.13 which places the study area in the 69th percentile nationally, meaning that the study area is well above the state and national levels.

The Superfund proximity indicator is the only EJ environmental indicator which is more than 80 percent above the state average. This means that the proposed site is closer than the state and national averages to a Superfund site. The Hassayampa Landfill is located approximately six miles northeast of the proposed site. According to the Arizona Department of Environmental Quality[36], the Hassayampa Landfill (site) is located about 10 miles west of Buckeye, Arizona, and approximately six miles east of the Palo Verde Nuclear Generating Station. The site consists of about 10 acres formerly used for hazardous waste disposal which lies adjacent to the 47-acre former sanitary landfill. The contaminants of concern in groundwater include various volatile organic compounds (VOCs) such as 1,1-dichloroethene (DCE), trichlorotrifluoroethane (Freon 113), 1,1,1-trichloroethane (TCA); 1,1-dichloroethane (DCA), trichloroethene (TCE), tetrachloroethene (PCE), trichlorofluoromethane (Freon 11); 1,2-dichloroethene (DCE), 1,2-dichloropropane, and toluene. Soils beneath the waste pits contain VOCs, heavy metals, pesticides, and lime wastes. Contaminants of concern at the site may change as new data becomes available.

Risk assessment results indicate that potential health risks may exist for individuals who might ingest the contaminated groundwater or come into direct contact with hazardous wastes present. The landfill is capped and enclosed by a perimeter fence; therefore, there is no potential for adverse health effects due to inhalation of VOCs in the air or direct contact with the hazardous wastes present below the ground surface. Contamination in the groundwater is contained within the site boundaries. The groundwater contamination is restricted to the shallow aquifer which is not used as a potable water source.

RMP Facility Proximity. The RMP (Risk Management Plan) facility proximity reflects the total count of active RMP facilities within 5 km. This is calculated by assigning distance weighted scores from active sites in EPA's Facility Registry Services (FRS) website. The study area value is 0.15 sites/km distance. The state value is 0.38 which puts the study area in the 50th percentile for the state. On a national level, the RMP facility proximity value is 0.43, putting the study area at the 44th percentile nationally. Therefore, the study area is at or slightly below the median for both the state and nation for proximity to facilities that have risk management plans.

Hazardous Waste Proximity. The Hazardous Waste Proximity indicator reflects the total count of hazardous waste facilities in each block group within 5 km of the average resident. This is calculated by assigning distance-weighted scores of hazardous waste facilities (Resource Conservation and Recovery Act handlers that are either operating Treatment, Storage, and Disposal Facilities (TSDFs) or hazardous waste Large Quantity Generator (LGQs)). The study area value for hazardous waste proximity is 0.021 facilities/km distance. When compared to the state value of 0.71, the study area is in the 5th percentile. The national Hazardous Waste Proximity indicator value is 1.9, putting the Study Area in the 2nd percentile. This means that the study area has a much lower proximity to hazardous waste facilities than either the state or national averages.

Underground Storage Tanks. The Underground Storage Tanks (UST) indicator quantifies the relative risk of being affected by a leaking underground storage tank (LUST). This is calculated by adding the number of LUSTs (multiplied by 7.7) and the number of USTs within 1500 ft of a block group. The value of the study area is 0.018 UST/km^2. This value is much less than the average value for the state of 1.7 and far below the national average of 3.9. This puts the study area in the 31st and 23rd percentile for the state

[36] https://azdeq.gov/node/3840

and national average, respectively. Therefore, the study area is much less likely to have leaking underground storage tanks nearby than in the state or nation.

Wastewater Discharge. The wastewater discharge indicator quantifies a block group's relative risk of exposure to pollutants in downstream water bodies. This is calculated from the Discharge Monitoring Report and RSEI model using a toxicity-weighted concentration in stream reach segments within 500 meters. The study area value of 0.27 is in the 66th percentile for the state which has an average value of 5.8. From a national perspective, it is in the 87th percentile where the national average is 22. This means that the study area has an elevated potential for exposure to pollutants from wastewater discharge as compared to both the state and nation.

14.5.8 Local Sensitive Receptors.

EPA's EJ guidance suggests that sensitive receptors include, but are not limited to, hospitals, schools, daycare facilities, elderly housing and convalescent facilities[37]. These are areas where the occupants are more susceptible to the adverse effects of exposure to toxic chemicals, pesticides, and other pollutants. For instance, children and the elderly may have a higher risk of developing asthma from elevated levels of certain air pollutants than healthy individuals between the ages of 18 and 64. Extra care must be taken when dealing with pollutants in close proximity to areas recognized as sensitive receptors.

The only sensitive public receptor identified within the study area is the Arlington Elementary School:

Arlington Elementary School
9410 S 355th Avenue
Arlington, AZ 85322
School ID: 040084000044
School district ID: 0400840

14.5.9 Step Three: Identify Potentially Adverse or Disproportionate Impacts within the Study Area.

Figure 14-4 depicts EPA's EJScreen "EJ Index" results for the study area. As previously noted, the EJ Index is an amalgam of the specific Environmental Indicator and two Demographic Indicators (low income and people of color).

From Figure 14-4, all of the thirteen (13) EJ Indexes for the study area are below EPA's 80th percentile flag for further scrutiny. However, from the EJ report, the Superfund proximity indicator for the study area was at the 84th percentile for the state which is the only EJ environmental indicator more than 80 percent above the state average. The Hassayampa Landfill is located approximately 6 miles northeast of the proposed site. Risk assessment results indicate that potential health risks may exist for individuals who might ingest the

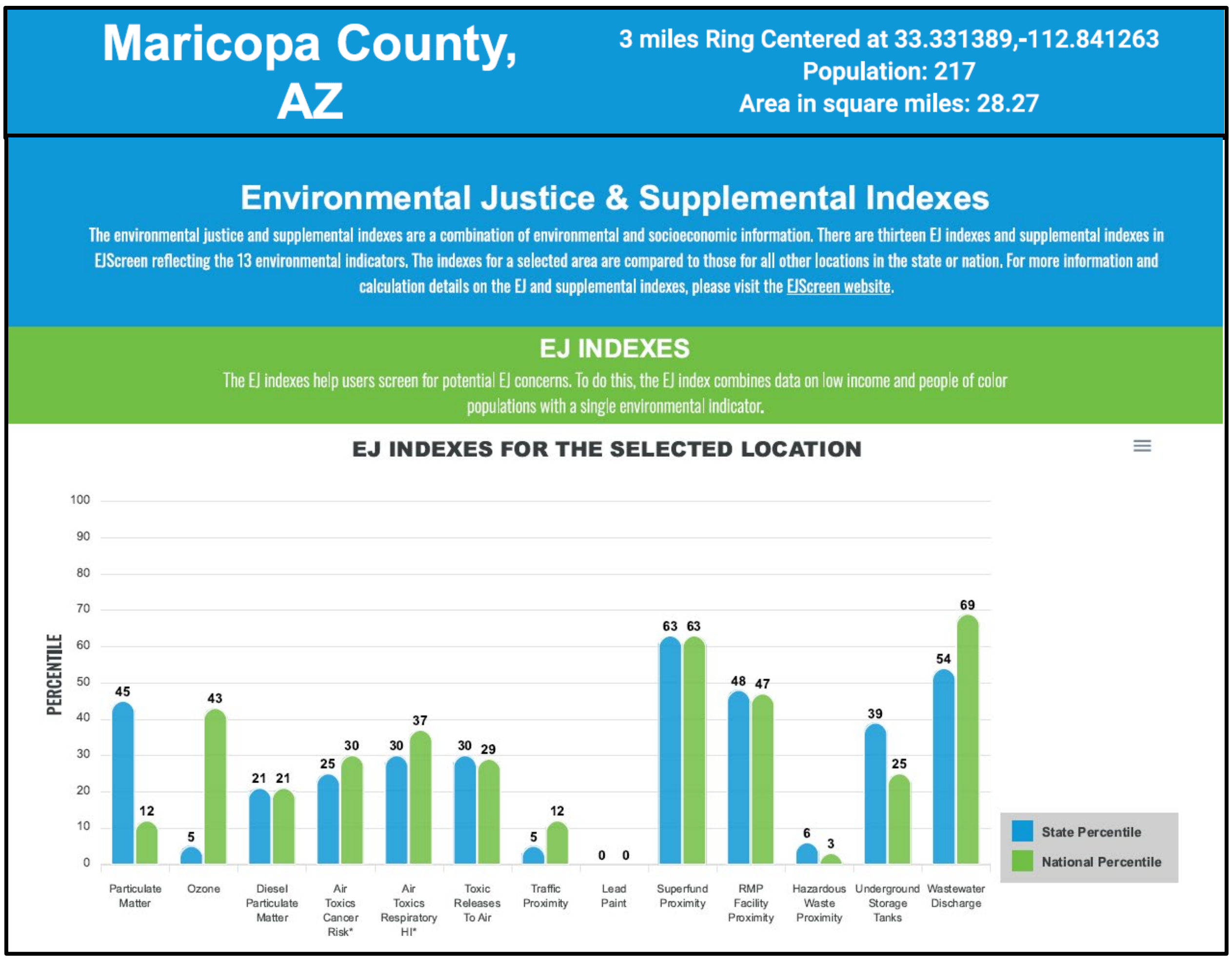
[37] Environmental Protection Agency | Environmental Issues of Concern for Urban Communities: Resources

contaminated groundwater or come into direct contact with hazardous wastes present. The landfill is capped and enclosed by a perimeter fence; therefore, there is no potential for adverse health effects due to inhalation of VOCs in the air or direct contact with the hazardous wastes present below the ground surface. Contamination in the groundwater is contained within the site boundaries.

The present application is for an air permit amendment and is unrelated to and has no potential to impact the Hassayampa Landfill. Indeed, there are no relevant applicable requirements that could be inserted into this air permit that would mitigate or address concerns related to superfund sites which would be outside the purview of this application.

Based upon a review of all of the information in Steps one through three, this EJ analysis did not identify a community that is adversely or disproportionately impacted by the project.

FIGURE 14-4. EJ Index results for the Power Plant Study Area.



14.5.10 Step Four: Ensure Meaningful Involvement of Potentially Impacted Community Members.

Although APS did not identify a community with potentially adverse or disproportionate impacts, the spirit of environmental justice is to ensure the fair treatment and meaningful involvement of all communities. APS is working to ensure potentially affected populations have an appropriate opportunity to participate in decisions about our proposed activity and has listened to the concerns of all participants involved.

The following is a brief overview of the Communications Outreach that has been conducted to date.

14.5.11 Communication and Public Outreach.

The Redhawk Power Plant is a Title V major source and operates under Title V permit No. P0009401. APS is seeking a significant revision and major modification to this Permit to construct and operate eight additional combustion turbines with selective catalytic reduction (SCR) and oxidation catalyst air quality control systems. Maricopa County Rule 210 § 408.2 requires the Maricopa County control Officer to provide public notice of receipt of a complete application for major modifications by publishing a notice in a newspaper of general circulation in Maricopa County. Maricopa County Rule 210 § 408.1(b) also requires the Maricopa County Control Officer to provide public notice, an opportunity for public comment, and an opportunity for a hearing before issuing or denying a significant permit revision. This requirement to provide public notice, an opportunity for public comment, and an opportunity for a hearing will help to facilitate meaningful community engagement before a final decision on this permit revision application is made.

APS will conduct community outreach for this permit application, to ensure that potentially impacted community members and businesses have an opportunity to better understand the project and its anticipated impacts, to ask questions, and to voice any concerns. Residents within three miles of the RHPPEP have a high proficiency with the English language. Regardless, 20% of homes in the Maricopa County area primarily speak Spanish. As part of its public outreach, APS will ensure that materials are published in both English and Spanish.

To provide information about the project and ample opportunity for the community to provide comment, APS will provide a variety of engagement opportunities and an in-person open house event as follows:

- On or around April 12, 2024, mail newsletters to homes and businesses within the study area, informing community members about the project and inviting them to the in-person and virtual open houses. The newsletter will be in both English and Spanish.
- On or around June 6, 2024, hold an in-person open house for community members. The timing of the event will be chosen to provide a long enough window to accommodate varying work and family schedules.
- A virtual open house (www.apsredhawkproject.com) will be made available to the public, commencing on 04/10/24 and will include informational materials in English and Spanish, and an opportunity to leave comments, concerns, or questions. This provides an opportunity for those

who cannot attend the in-person open house an alterative option for learning more and engaging with comments or questions.

- All project materials contain an e-mail address (apsredhawkproject@aps.com), a phone number (800-484-1358), and a project web address (www.apsredhawkproject.com) for community members who wish to engage and communicate with project staff. These channels of communication will be monitored, and responses will be provided in a timely manner.
- On or around May 7 through May 21, 2024, geotargeted social media ads will be placed to inform community members and businesses about the project and the virtual and in-person open house options.

APS will continue to monitor input from community members, and as additional community input is gathered, APS will supplement the permit record for this application.

14.6 Conclusions.

Environmental Justice (EJ) is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This EJ evaluation examined the demographic and environmental conditions within the three-mile radius, known as the "study area," centered around the existing Redhawk Power Plant in Maricopa County, and compared those demographic and environmental conditions to the County, the State of Arizona, and to the nation as a whole. This analysis did not identify any potentially significant adverse or disproportionate impacts to the community within the study area. The following are the major findings for the study area in this analysis.

1. The study area has a low population of only 217 individuals in an area of 28.27 square miles, equal to a population density of less than 8 individuals per square mile.
2. The EJ screening socioeconomic factors for the study area have a lower percentage of individuals in all selected EJ screening variables except "Less Than High School Education" and "Low Life Expectancy" as compared to both the County and the State.
    a. The study area has a higher percentage of the population (31%) with less than a high school education than both the County (12%) and the State (12%).
    b. The study area has a slightly higher low life expectancy (20%) than the state as a whole (19%).
3. The study area's population of all ethnic groups is lower as a percentage than the County and State except for the total Hispanic population (35%) which is 10% greater than the County (31.1%).

4. The per capita income in the study area ($33,108) is also more than 10% less than both Maricopa County ($37,570) and the State of Arizona ($38,334), indicating that the local population has a lower income than the county or state averages.
5. None of the households have limited English proficiency or speak another language at home. Thus, the study area appears to have a very high English proficiency.
6. The Superfund proximity indicator for the study area was the only EJ environmental indicator which is more than 80 percent above the state average. However, the landfill is capped. There is no potential for adverse health effects due to inhalation of VOCs in the air or direct contact with the hazardous wastes present below the ground surface.

Even though APS did not find adverse or disproportionate impacts to the community, APS will work to ensure that there was and will continue to be meaningful involvement, engagement and dialogue with the community around the proposed new power plant.

Appendix A.

Maricopa County Air Quality Department Forms.

SECTION 1 STANDARD PERMIT APPLICATION FORM

TITLE V PERMIT APPLICATION

As required by A.R.S. § 49-480 and Rule 210 (Title V Permit Provisions)

ALL APPLICANTS MUST COMPLETE THE ENTIRE APPLICATION

Important: Please note that as the engineer reviews your application and prepares your permit, email will be the **primary** means for communication with you, unless you do not have an email address. Please ensure your email address is correct.

1. Permit to be issued to (Business license name of organization that is to receive permit):
Arizona Public Service Company (APS)

2. Mailing Address: **400 N. 5th Street, Mail Station 9303**

City: **Phoenix**	State: **Arizona**	Zip Code: **85004**

3. Plant Name (if different from item #1 above): Redhawk Generating Station

4. Name (or names) of Owner or Operator:
Arizona Public Service Company
Phone: ______ Email : ______

5. Name of Owner's Agent: **Mark Hajduk**
Phone: 602-**250-3394**

6. Plant/Site Manager or Contact Person: **Andre Bodrog**
Phone: **(602) 407-7801**

7. Proposed Equipment/Plant Location Address:
11600 South 363rd Avenue

City: **Arlington**	County: **MARICOPA**	Zip Code: **85322**

Section/Township/Range: ______

Latitude: **33.3332**	Longitude: **-112.8412**	Zip Code:

8. General Nature of Business: **Electrical Power Generation**

Standard Industrial Classification Code: **4911**

9. Type of Organization: ■ Corporation ☐ Individual Owner ☐ Partnership ☐ Govt. Entity
Government Facility Code: ______

10. Permit Application Basis (Check all that apply.): ☐ New Source ☐ Renewal of Existing Permit ■ Revision P0009401 ☐ Portable Source

For renewal or modification, include existing permit number and Date of Commencement of Construction or Modification: 04/01/2023

Is **any** of the equipment to be leased to another individual or entity? ☐ Yes ■ No

11. Signature of Responsible Official: *Andre Bodrog*
Official Title of Signer: ______

12. Typed or Printed Name of Signer: Andre Bodrog

Date: 12/11/2024 Phone: (602) 407-7801

For Office Use Only	Date Received:	Log Number:

Appendix B.

Air Quality Modeling Protocol and Report.

Appendix C.

Environmental Justice EJScreen Data for the Redhawk Power Plant Project.