Exhibit 5

Ocotillo Power Plant, Modified Air Permit Application
(“Revised App.) (Sept. 30, 2015)

aps

MARICOPA COUNTY
AIR QUALITY DEPT

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September 29, 2015

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Mr. Phillip A. McNeely, Director
Maricopa County Air Quality Department
1001 North Central Ave, Suite 125
Phoenix, AZ 85004

Subject: Amended Application for the Significant Permit Modification Application for Air Quality Permit V95-007 – Ocotillo Power Plant

Mr. McNeely,

This document is being submitted pursuant to Rule 210, Section 406 of the Maricopa County Air Pollution Control Regulations, and constitutes an amended application by Arizona Public Service (APS) for the significant permit modification to the Ocotillo Title V Air Quality Operating Permit (V95-007).

This amended application submittal incorporates revisions that include; updated GHG BACT analysis and emergency generator information as well as other information requested by Maricopa County. Please note, additional information regarding the air quality analysis protocol and report and Environmental Justice will be submitted at a later date.

If you require additional information or have any questions regarding the application, please contact Anne Carlton at (602) 250-5153.

Based on the information and belief formed after reasonable inquiry, the statements and information in this document are true, accurate, and complete.

Sincerely,

Dennis L Irvin

Dennis Irvin
Plant Manager
Ocotillo Power Plant
Arizona Public Service Company

cc: US EPA, Region IX
Air Permits Office
75 Hawthorne St
San Francisco, CA 94105

Title V Operating Permit Revision and Prevention of Significant Deterioration

Air Pollution Control Permit Application

Ocotillo Power Plant Modernization Project

Application to construct five (5) new natural gas-fired General Electric LMS100 simple cycle gas turbines.

Original Date: **April, 2014**
Updated: **September 30, 2015**

Prepared for:

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Executive Summary.

This document is submitted pursuant to Rules 210 and 240 of the Maricopa County Air Pollution Control Regulations (MCAPCR), and constitutes an updated application by Arizona Public Service Company (APS) for a significant permit revision to construct and operate new electric power generation equipment at the existing Ocotillo Power Plant in Tempe, Maricopa County, Arizona.

APS plans a major modernization project at the Ocotillo Power Plant (the Project). APS plans to install five General Electric Model LMS100 102-megawatts net (nominal summer rating) simple-cycle gas turbine generators (GTs) powered by clean pipeline-quality natural gas. The two existing 1960s-era steam electric generators and the associated cooling towers will be decommissioned as part of the Project. This Project will provide many benefits for customers and the surrounding area. The Project will create a cleaner-running, more efficient plant; support service reliability and renewable resources for customers in the Phoenix metro area; and create jobs and additional tax revenue for the local economy.

The Project will utilize state-of-the-art gas turbine technology to generate electricity. 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. This means that APS must have firm electric capacity which can be quickly and reliably dispatched when renewable power or other distributed energy sources are unavailable. In addition, because customers use energy in different ways and at different times, this can create multiple times of peak demand throughout the day. The LMS100 GTs have the quick start and power escalation capability that is necessary to meet changing power demands and mitigate grid instability caused by the intermittency of renewable energy generation. The new units need the ability to start quickly, change load quickly, and idle at low load. This capability is very important for normal grid stability, but absolutely necessary to integrate with and fully realize the benefits of distributed energy such as solar power and other renewable resources. To achieve these requirements, these GTs will be designed to meet the proposed air emission limits at steady state loads as low as 25% of the maximum output capability of the turbines.

This application describes the proposed Project equipment and schedule, the Project air emissions and proposed control technologies, the regulatory programs that apply to the GTs, an air quality impact analysis, and the proposed permit conditions and compliance demonstration methods. The conclusions presented in this air permit application for the Ocotillo Modernization Project are that:

- The Ocotillo plant will utilize highly efficient simple-cycle gas turbines.
- PSD permitting requirements apply to the Project only for CO, PM, $PM_{2.5}$, and GHG emissions. The proposed control technologies and emission limits for these pollutants represent the Best Available Control Technology (BACT) for simple-cycle gas turbines.
- After completion of the Project, the Ocotillo Plant will no longer be a major source of PM_{10}.
- Nonattainment NSR permitting requirements do not apply to the Project.
- Air quality impacts of the Project are insignificant when compared to EPA impact thresholds.

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Chapter 1. Introduction.

This document is submitted pursuant to Rules 210 and 240 of the Maricopa County Air Pollution Control Regulations (MCAPCR), and constitutes an updated application by Arizona Public Services Company (APS) for a significant permit revision to construct and operate new electric power generation equipment at the existing APS Ocotillo Power Plant in Tempe, Maricopa County, Arizona. The Ocotillo Modernization Project (the Project) is being proposed because of the need for additional electrical generation in the Phoenix area. The Project will utilize state-of-the-art gas turbine technology.

The Ocotillo Power Plant is located at 1500 East University Drive, Tempe Arizona, 85281, in Maricopa County. The Ocotillo Power Plant and the proposed Project are classified under Standard Industrial Classification (SIC) code 4911. The plant latitude is 33.425 and longitude is 111.909 at a base elevation of 1,175 feet above mean sea level (AMSL). The Ocotillo plant has been in operation since 1960 and currently consists of two steam boiler generating units and two simple cycle gas turbine generators (GTs). The steam boiler generating units have a rated heat input capacity of 1,210 MMBtu/hr and an electric power output capacity of 110 MW each. Two cooling towers are used to supply cooled circulating water to the steam unit condensers, with rated capacities of 58,800 gallons per minute (gpm). The existing GTs are General Electric (GE) Model 501-AA units installed in 1972 and 1973. Each turbine has a rated heat input capacity of 915 MMBtu/hr and an electric output capacity of 55 MW. A GENRAC 125 hp propane-fired emergency generator is also installed at Ocotillo. This unit is limited to no more than 500 operating hours per year. The Ocotillo Power Plant is a major stationary air emission source as defined in MCAPCR Rules 210 and 240, and operates under Title V Operating Permit V95-007.

APS is planning to install five (5) new natural gas-fired GE Model LMS100 simple cycle GTs and associated equipment at the Ocotillo Power Plant. As part of the Project, APS plans to retire the existing steam electric generating units 1 and 2 and associated cooling towers before commencing commercial operation of the proposed new GTs. This document is an application by APS for a significant permit revision to allow for construction and operation of the proposed Project. Chapter 2 of this application is a description of the proposed Project equipment and schedule. Chapter 3 presents a summary of Project emissions and proposed emission limits. Chapter 4 describes the regulatory programs that apply to the GTs, including two sets of New Source Review (NSR) regulatory applicability analyses, one that addresses the Prevention of Significant Deterioration (PSD) rules and a second that address Non-Attainment NSR (NANSR) rules. Chapter 5 summarizes the proposed control technologies and emission limits. Chapter 6 discusses the air quality impact analyses. Chapter 7 presents the proposed permit conditions, limits, and compliance demonstration methods.

1.1 Permit Application Forms.

Included in Appendix A of this application are the Maricopa County Air Quality Department STANDARD PERMIT APPLICATION FORM and the EMISSION SOURCES FORM for each emissions unit. Also attached is the information requirements identified in the STANDARD PERMIT APPLICATION FORM AND FILING INSTRUCTIONS. Table 1-1 summarizes the location of this required information in the permit application.

TABLE 1-1. Summary of the Maricopa County Air Quality Department's permit application additional 19 information items, and the location of this information in this application.

Item	Description	Location of Information in this Application
1	Description of process to be carried out in each unit (include Source Class. Code, if known).	Chapter 2
2	Description of product.	Chapter 2 (Product is electricity.)
3	Description of alternate operating scenario, if desired by applicant.	NONE REQUESTED
4	Description of alternate operating scenario product, if applicable.	NONE REQUESTED
5	A flow diagram for all processes.	Chapter 2
6	A material balance for all processes (only if emission calcs are based on a material balance).	Chapter 2 and Appendix B (for GHG emissions).
7	Emissions related information: a. Potential emissions of regulated air pollutants. b. Identify and describe all points of emissions.	Chapter 2, Chapter 6, and Appendix A.
8	Citation and description of all applicable requirements.	Chapter 4
9	Explanation of any voluntarily accepted limits established pursuant to Rule 220 and any proposed exemptions from applicable requirements.	Chapters 3, 4, 5, and 8
10.	The following information to the extent it is needed to determine or regulate emissions or to comply with the requirements of Rule 220:	
10a.	Maximum annual process rate for each piece of equipment which generates air emissions.	Chapter 2 and Chapter 3
10b.	Maximum annual process rate for the whole plant.	Based on voluntarily accepted limits described in Chapters 4 and 5.
10c.	Maximum rated hourly process rate for each piece of equipment which generates air emissions.	Chapter 2 and Chapter 3 (The maximum process rate is based on the maximum capacity of each emissions unit).
10d.	Maximum rated hourly process rate for the whole plant.	The maximum rated hourly process rate for the whole plant is based on all emissions units operating simultaneously at their maximum rated capacities.
10e.	For all fuel burning equipment, a description of fuel use, including type, quantity per year, quantity per hour, and HHV of the fuel.	Chapter 2 and Chapter 3
10f.	Description of all raw materials used and the maximum annual, hourly, monthly, or quarterly quantities of each material used.	Chapter 2. Raw materials include natural gas fuel, water for cooling and NO_X control, and ammonia (NH3) for SCR NO_X control.
10g.	Anticipated operating schedules: 1. Percent of annual production by season. 2. Days of the week normally in operation. 3. Shifts or hours of the day normally in operation. 4. Number of days per year in operation.	The units will be operated on an "as-needed" basis 365 days per year

TABLE 1-1. Summary of the Maricopa County Air Quality Department's permit application additional 19 information items, and the location of this information in this application.

Item	Description	Location of Information in this Application
10h.	Limitations on source operations and any work practice standards affecting emissions.	Based on voluntarily accepted limits described in Chapters 3, 4, 5, and 8.
10i.	A demonstration of how the source will meet any limits accepted voluntarily pursuant to Rule 220.	Chapters 3 and 8.
11	A description of all process and control equipment for which permits are required including: Name, Make, Model, Serial number, Date of manufacture, Size/production capacity, and Type.	Chapter 2 and Chapter 3.
12	Stack Information, including Identification, Description, Building dimensions, Exit gas temperature, Exit gas velocity, Height, and Inside dimensions.	Chapter 2 and Chapter 6, and attached Standard Forms.
13	Site diagram which includes Property boundaries, Adjacent streets, Directional arrow, Elevation, Closest distance between equipment and property boundary, Equipment layout, Location of emission sources or points, Location of emission points and areas, Location of air pollution control equipment.	Chapter 2 and Chapter 6.
14	Air pollution control information:	
14a.	Description of test method for determining compliance with each applicable requirement.	Chapter 8.
14b.	Identification, description and location of air pollution control equipment, and compliance monitoring devices or activities.	Chapters 2 and 3 and Appendix B.
14c.	The rated and operating efficiency of air pollution control equipment.	Chapters 2 and 3 and Appendix B.
14d.	Data necessary to establish required efficiency for air pollution control equipment (warranty information).	Chapters 2 and 3 and Appendices B and C.
14e.	Evidence that operation of the equipment will not violate any ambient air quality standards, or maximum allowable increases.	Chapter 6.
15	Equipment manufacturer's bulletins and shop drawings may be acceptable where appropriate.	Not applicable.
16	Compliance Plan	Chapter 4.
17	Compliance Certification	Appendix A.
18	Rule 240 submittal information	Chapters 4 and 8.
19	Calculations on which all information requested in this Appendix is based.	Chapters 2, 3, and 6.

Chapter 2. Project and Process Description.

2.1 Project Overview.

APS is planning to install five (5) new natural gas-fired General Electric Model LMS100 simple cycle gas turbine generators, a hybrid cooling system, and associated equipment at the Ocotillo Power Plant in Tempe, Maricopa County, Arizona. Figure 2-1 presents the general location of the Ocotillo Power Plant, and Figure 2-2 presents an aerial image of the existing plant.

FIGURE 2-1. Locus map showing the general location of the Ocotillo Power Plant.

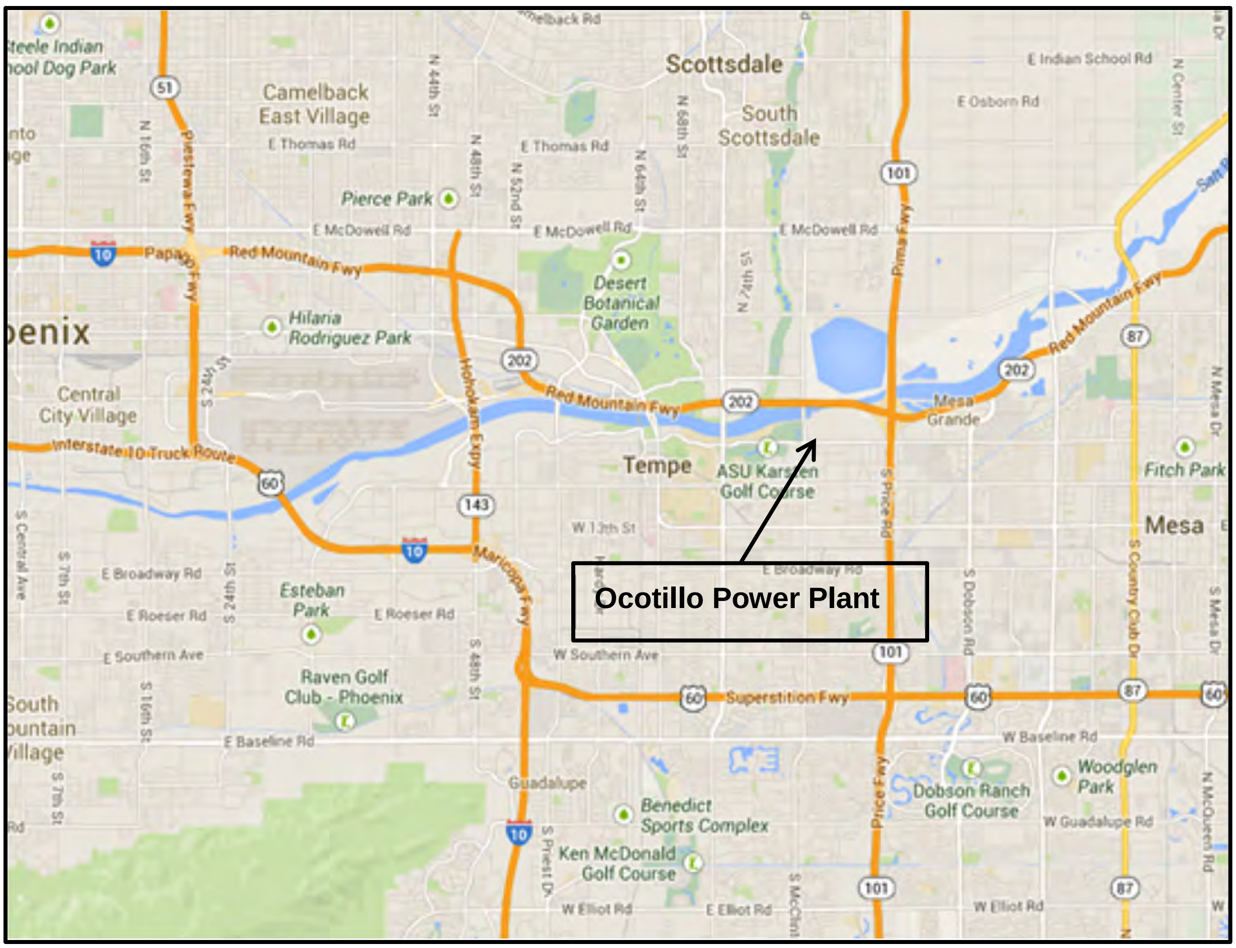

FIGURE 2-2. Aerial image of the existing Ocotillo Power Plant.

2.2 Project Purpose and Need.

The purposes for the Project are to provide peaking and load shaping electric capacity in the range of 25 to 500 MW (including quick ramping capability to backup renewable power and other distributed energy sources), to replace the 200MW of peak generation that will be retired at Ocotillo with cleaner units, and to provide an additional 300MW of peak generation to handle future growth. This Project has been reviewed and the Certificate of Environmental Compatibility has been approved by the Arizona Corporation Commission (ACC) after a lengthy public comment period and hearing process.

APS is continuing to add renewable energy, especially solar energy, to the electric power grid, with the goal of achieving a renewable portfolio equal to 15% of APS's total generating capacity by 2025 as mandated by the ACC. However, because renewable energy is an intermittent source of electricity, a balanced resource mix is essential to maintain reliable electric service. As of January 1, 2015, APS has approximately 1,200 MW of renewable generation and an additional 46 MW in development. Within Maricopa County and the Phoenix metropolitan area, APS has about 115 MW of solar power and there is an additional 300 – 400 MW of rooftop Photovoltaic (PV) solar systems.

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, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, 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[1]. Considering the solar capacity in Maricopa County, the required electric generating capacity ramp rate required to back up these types of solar systems would therefore range from 165 to 310 MW per minute. The actual renewable energy load swings experienced on the APS system have also shown rapid load changes from renewable energy sources of 25 to 300 MW in very short time periods, in agreement with the estimates found in the EPRI study.

To backup the current and future renewable energy resources, the Project design requires quick start and power escalation 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 five General Electric (GE) LMS100 gas-fired simple cycle combustion turbine generators (GTs), which have the capability to meet these design needs while complying with the proposed BACT air emission limits at loads ranging from 25% to 100% of the maximum output capability of the turbines. The proposed LMS100 GTs can provide an electric power ramp rate equal to 50 MW per minute per GT which is critical for the project to meet its purpose. When all 5 proposed GTs are operating at 25% load, the entire project can provide approximately 375 MW of ramping capacity (i.e., from 125 to 500 MW) in less than 2 minutes.

[1] 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.

2.3 GE LMS 100 Gas Turbine Generators

The General Electric Model LMS100 simple cycle gas turbine (GT) generator utilizes an aero derivative gas turbine coupled to an electric generator to produce electric energy. A gas turbine 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, inlet chiller, 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 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 the electric generator.

Figure 2-3 presents a process flow diagram for the LMS 100 turbine. The LMS100 GTs are 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 by contacting the air with an inlet chiller. The filtered and cooled air is drawn into the low-pressure compressor section of the gas turbine where the air is compressed. The air temperature rises along with the increase in pressure. The LMS100 then uses an innovative intercooling system which takes the air out of the turbine, cools it to an optimum temperature in an external water-cooled heat exchanger (the intercooler), and then redelivers it to the high-pressure compressor. The near constant stream of low temperature air to the high pressure compressor reduces the work of compression, resulting in a higher pressure ratio (42:1), increased mass flow, and increased power output. This reduced work of compression also improves the overall gas turbine thermal efficiency.

The high-pressure compressed air from the high-pressure compressor discharge flows to the combustion section of the turbine 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 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 compressed gases which cools and reduces the pressure of the exhausted gases. The power section of the turbine produces the power to drive the electric generator. The use of the intercooler combined with higher combustor firing temperatures allows the LMS100 to achieve a simple cycle thermal efficiency of approximately 43.9% ast ISO conditions.

A typical LMS 100 installation is shown in Figure 2-4. The general specifications for these turbines are summarized in Table 2-1. Note that the specifications in Table 2-1 are for new turbines which have not undergone any performance degradation due to normal operation, and also do not account for efficiency reductions due to additional post combustion emission control systems.

FIGURE 2-3. Diagram of a General Electric Model LMS100 simple cycle gas turbine (from General Electric Company).

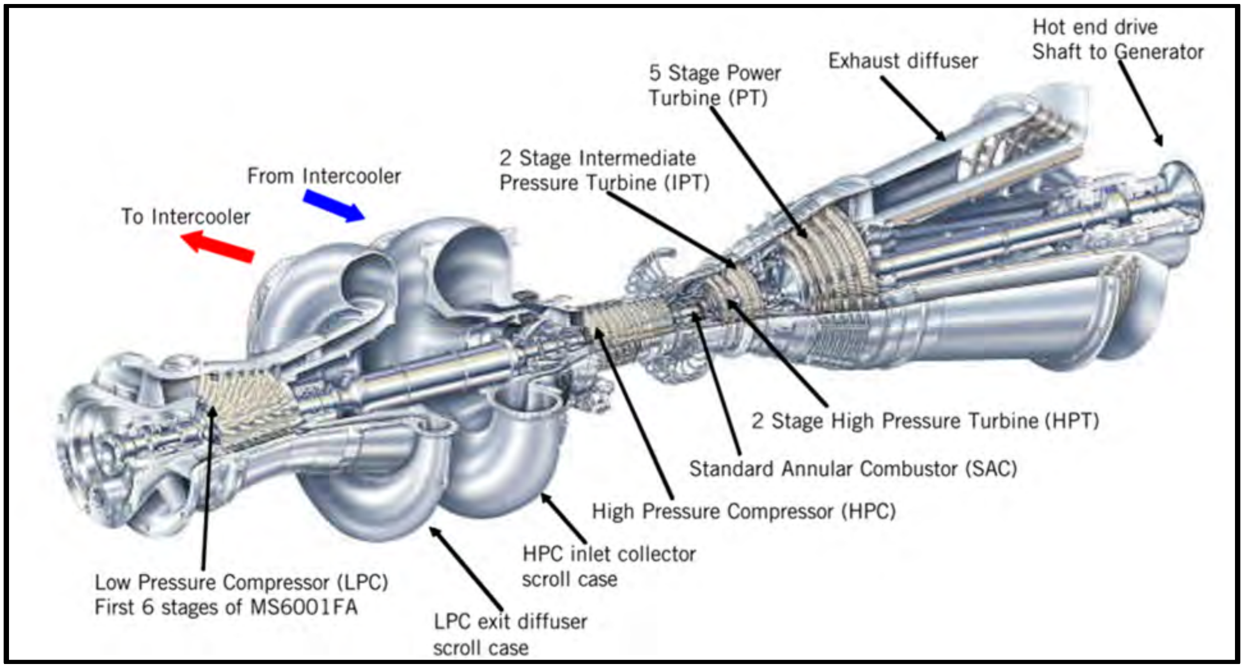

FIGURE 2-4. Typical installation of a General Electric Model LMS100 simple cycle gas turbine (from General Electric Company).

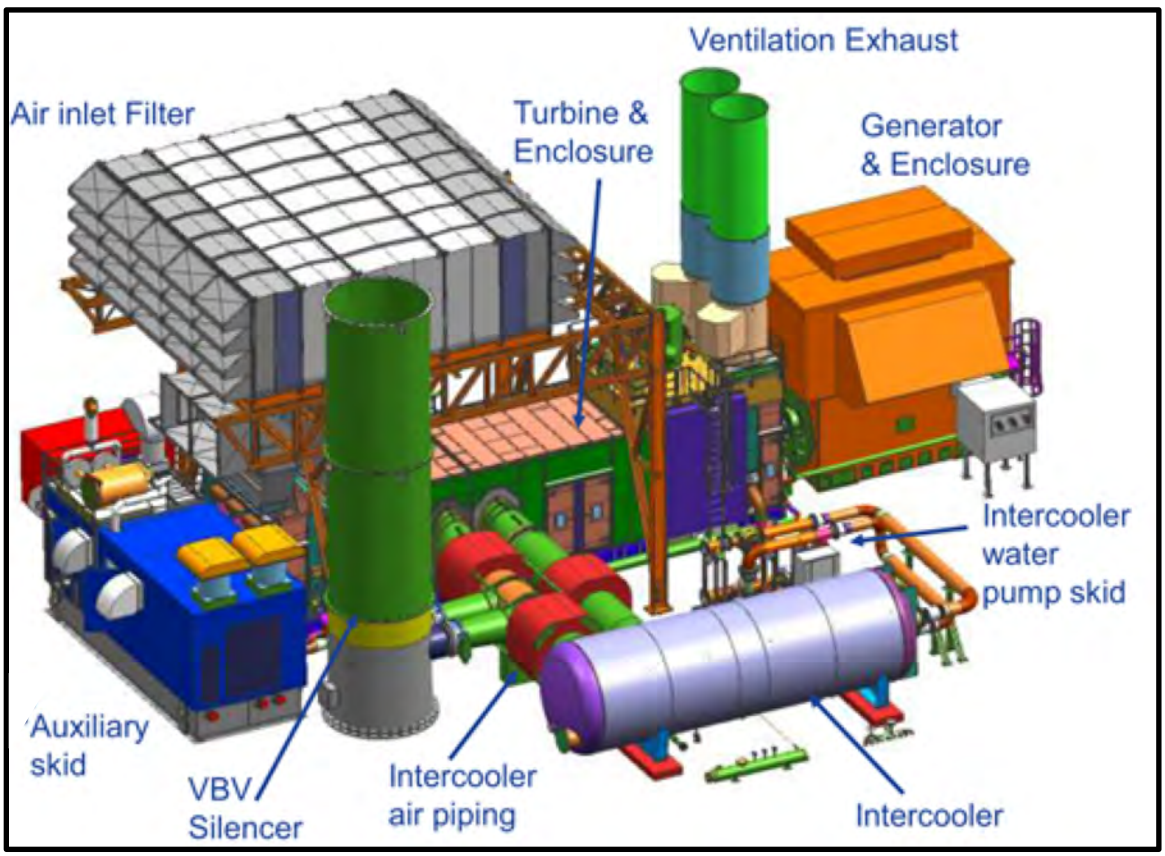

TABLE 2-1. General specifications for the proposed General Electric Model LMS100 simple cycle gas turbines.

LMS100 Model	PA - 60 Hz
Output Power (gross)	111MW
Efficiency (ISO)	43.9%
LPT Speed	3,600 RPM
Heat Rate ISO Full Load (gross)	8,939 Btu/kWh HHV

The gas turbine and generator will be enclosed in a metal acoustical enclosure which will also contain accessory equipment. The GTs will be equipped with the following equipment:

- Inlet air filters
- Inlet air chillers
- Metal acoustical enclosure to reduce sound emissions
- Duplex shell and tube lube oil coolers for the turbine and generator
- Annular standard combustor combustion system
- Water injection system for NO_x control
- Compressor intercooler system
- Water saving hybrid intercooler cooling system
- 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.

2.3.1 Post Combustion Air Quality Control Systems.

The combustion gases exit the turbine at approximately 760ºF. 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.

For natural gas-fired gas turbines applications, CO and VOC emission 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). Oxidation catalysts have the potential to achieve 90% reduction in uncontrolled CO emissions at steady state operation. VOC reduction capabilities are expected to be less.

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 vapor. For this simple cycle gas turbine application, the SCR system will be a hot SCR which operates at relatively high flue gas temperatures in excess of approximately 750 ^oF.

During operation, a 19% aqueous solution of ammonia will be vaporized and injected into the turbine exhaust gas stream upstream of the SCR catalyst. The ammonia will react with NO_X, with expected NO_X reduction efficiencies of approximately 90%. After passing through the SCR, the exhaust gases exit through a separate stack for each GT.

2.4 Hybrid Cooling Tower.

The closed-loop cooling system provides water cooling for the High Temperature Intercooler (HTIC) at each LMS100 GT. The HTIC water flow requirements for all GTs are combined into a common system that uses a hybrid Partial Dry Cooling System (PDCS) closed cycle cooling water rated at 52,500 gallons per minute (gpm) and wet cooling of 61,500 gpm to provide the cooling necessary for maximum performance and efficiency of the GTs.

In this hybrid PDCS system, the heat is rejected using ambient air in a dry cooling system followed by a conventional wet cooling tower. This PDCS reduces water consumption in two ways. The dry-cooling section reduces the amount of heat going to the wet cooling tower which reduced water use. The dry cooling portion has no air emissions. The mechanical induced-draft cooling tower will have emissions of particulate matter (PM). The plant design specifies a Marley model F454A45E4.006A 6-cell counter flow cooling tower with the TU12 Drift Eliminator system.

2.5 Emergency Diesel Electric Generators.

The Ocotillo Modernization Project will include the proposed installation of two 2.5 megawatt (MWe) mission critical emergency generators powered by diesel (compression ignition) engines. Because these new generators will be used as emergency diesel generators, APS is proposing to utilize generators equipped with Tier 2 engines and with operational limits for each generator of no more than 500 hours in any 12 consecutive month period. This operational limit is explained in more detail in Chapters 3 and 4. Table 2-2 is a summary of the technical specifications for each emergency generator.

TABLE 2-2. Specifications for the proposed new emergency generators.

Generator Standby Rating, kW	2,500
Engine Type	Diesel (Compression Ingnition)
Engine Power at Standby Output, brake-horsepower	3,386
Engine Displacement, L	78
Engine Cylinders	V-16
Engine Displacement per Cylinder, L	4.88
Maximum Diesel Fuel Consumption Rate, gal/hr	175
Exhaust Gas Flowrate, acfm	19,600
Exhaust Gas Temperature, ^{o}F	794
NO_x Emission Controls	None
PM and VOC Emission Controls	None

Footnotes

The maximum generator output rating, fuel consumption rating, emissions, and flowrates are based on the generator standby rating, which is the maximum short term capacity of the generator.

2.6 Summary of the Project Emission Units.

In addition to the combustion turbines, cooling tower, and emergency generators, the Project equipment will include two 10,000 gallon diesel fuel oil storage tanks, SF_6 insulated electrical equipment, and natural gas piping systems and components. Table 2-3 is a summary of the proposed new emission units for the Ocotillo Modernization Project.

TABLE 2-3. Proposed emission units for the Ocotillo Modernization Project

Emission Unit	Designation	Description
1	GT3	GE Model LMS100 simple cycle gas turbine Unit 3
2	GT4	GE Model LMS100 simple cycle gas turbine Unit 4
3	GT5	GE Model LMS100 simple cycle gas turbine Unit 5
4	GT6	GE Model LMS100 simple cycle gas turbine Unit 6
5	GT7	GE Model LMS100 simple cycle gas turbine Unit 7
6	GTCT	Cooling Tower
7	EG1	Emergency Diesel Generator 1
8	EG2	Emergency Diesel Generator 2
9	SF6	SF_6 Insulated Electrical Equipment
10	DFT1 and DFT2	Two 10,000 gallon diesel fuel oil storage tanks
11	NGPS	Natural Gas Piping Systems

Chapter 3. Project Emissions.

3.1 GE LMS 100 Gas Turbine Generators.

3.1.1 Normal Operation

The manufacturer's emissions data are presented in Appendix C for a wide range of unit operating load and ambient air conditions. The potential emissions for each GT are based on the maximum nominal rated heat input for the gas turbines of 970 mmBtu per hour (higher heating value or HHV), and the proposed BACT emission limits and manufacturer's maximum hourly emission rates. In this application, APS is not proposing limits on the hours of turbine operation. Instead, to increase operational flexibility, APS is proposing the following enforceable emission and operating limits which will limit the potential emissions of each regulated pollutant:

- Emission caps across the proposed new gas turbines GT3 - GT7 and the two new emergency generators of 125.3 tons per year (TPY) for NO_x so that the Project (in combination with the contemporaneous emission decreases from retiring of the steam units) does not result in a net emission increase greater than 40 TPY. This emission cap ensures that the Project does not trigger PSD or NANSR permitting requirements for NO_X emissions,
- A plant-wide PM_{10} emission cap of 63.0 TPY to reclassify the Ocotillo Plant as a minor source of PM_{10} emissions under the PM_{10} NANSR rules, so that the Project does not trigger NANSR permitting requirements for PM_{10},
- An annual fuel use limit of 18,800,000 MMBtu/year (HHV) combined across the new gas turbines GT3 - GT7 to limit the potential emissions of CO, VOC, HAPs, SO_2, and Greenhouse Gases (GHG),
- A startup and shutdown limit of 2,490 hours of total startup and shutdown for all 5 new gas turbines GT3 – GT7 combined averaged over any consecutive 12-month period, to limit CO and VOC emissions,
- An operating limit on each new emergency generators of 500 hours in any consecutive 12-month period,
- The net electric sales for each GT will be limited to no more than the design efficiency times the potential electric output on a 3-year rolling average. The design efficiency and potential electric output will be determined during the initial performance test using the methods referenced in 40 CFR 60 Subpart TTTT.
- An annual fuel use limit of 2,928,000 MMBtu/year (HHV) (1,600 hours per year per turbine) combined across the existing gas turbines GT1 - GT2 to limit the potential emissions for VOCs and HAPs, and
- Combustion of only pipeline quality natural gas in all of the existing and new gas turbines GT1 through GT7.

Compliance with these limits will be demonstrated using a combination of Continuous Emission Monitoring System (CEMS) data, fuel use data, emission factors, and operating hour records. Refer to Section 8 of this application for a detailed summary of the proposed emission limits and compliance demonstration methods. The potential emissions during normal operations for GT3 - GT7, based on the proposed annual fuel use limit, are summarized in Table 3-1.

3.1.2 Startup and Shutdown Emissions.

The gas turbine air pollution control systems including selective catalytic reduction (SCR) and oxidation catalysts are not operational during the startup and shutdown of gas turbines. 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.Water injection is also used to reduce NO_x emissions from these GTs 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.

For simple cycle gas turbines, the time required for startup is much shorter than gas turbines used in combined cycle applications. The expected emissions during a normal startup and shutdown are summarized in Table 3-2. For the LMS100 GT, the maximum length of time for a normal startup (the time from initial fuel firing to when the unit goes on line and water injection begins) is approximately 30 minutes. The maximum length of time for a normal shutdown, that is, the time from the cessation of water injection to the time when the flame is out, is normally 11 minutes. Therefore, the maximum normal duration for a normal startup and shutdown cycle or “event” is 41 minutes. In Table 3-2, the startup and shutdown emissions are detailed for one event, and the maximum emissions in one hour, assuming that the remaining 19 minutes in the hour are with the GT operating at its maximum rated capacity and maximum emission rate. The startup and shutdown annual emissions have been calculated based on a startup and shutdown annual operating limit of 2,490 hours of total startup and shutdown for all 5 new gas turbines combined. In addition, the fuel use during startup and shutdown is estimated based on 366 MMBtu per startup sequence and 43 MMBtu per shutdown sequence for a total of 409 MMBtu per 41 minute event. This equates to 1.49×10^6 MMBtu per year for all startup/shutdown events for all 5 turbines combined.

3.1.3 Potential Emissions for GTs.

The total potential emissions for the GTs are the sum of emissions during normal operation and the number of startup/shutdown hours, and are presented in Table 3-3.

TABLE 3-1. Potential emissions for the proposed new Model LMS100 gas turbines GT3-GT7 during normal operation.

POLLUTANT		Heat Input per GT	Maximum Emission Rate		Fuel Use Limit	Emissions per GT	Emissions for GT3-GT7
		NORMAL OPERATION					
		mmBtu /hr	ppmdv @ 15% O_2	lb/hr	10^6 MMBtu/yr	ton/year	ton/year
Carbon Monoxide	CO	970	6.0	13.5	18.8	24.1	120.7
Nitrogen Oxides	NOx	970	2.5	9.3	18.8	16.5	82.6
Particulate Matter	PM	970	NA	5.4	18.8	9.6	48.2
Particulate Matter	PM_{10}	970	NA	5.4	18.8	9.6	48.2
Particulate Matter	$PM_{2.5}$	970	NA	5.4	18.8	9.6	48.2
Sulfur Dioxide	SO_2	970	NA	0.6	18.8	1.0	5.2
Volatile Organic Compounds	VOC	970	2.0	2.6	18.8	4.7	23.6
Sulfuric Acid Mist	H_2SO_4	970	NA	0.06	18.8	0.10	0.52
Fluorides (as HF)	HF	970	NA	0.00	18.8	0.0000	0.0000
Lead	Pb	970	NA	0.00049	18.8	0.00087	0.0043
Carbon Dioxide	CO_2	970	NA	113,467	18.8	202,438	1,012,190
Greenhouse Gases	CO_2e	970	NA	113,584	18.8	202,647	1,013,235

Footnotes

1. Normal operation emissions are based on the total fuel use limit of 18.8 x 10^6 MMBtu/yr **LESS** fuel use during startup/shutdown of 1.49 x 10^6 MMBtu/yr.
2. The SO_2 emission factor of 0.0006 lb/MMBtu is based on pipeline quality natural gas. Sulfuric acid mist is estimated as 10% of the SO_2 emissions.
3. The emission factors for the greenhouse gases are from 40 CFR 98, Tables C-1 and C-2 and 40 CFR 98, Subpart A, Table A-1.

Pollutant		Emission Factor	Total GHG Emission Factor	
		lb/mmBtu	CO_2e Factor[4]	lb/mmBtu
Carbon Dioxide	CO_2	116.98	1	116.976
Methane	CH_4	0.0022	25	0.055
Nitrous Oxide	N_2O	0.00022	298	0.066
TOTAL GHG EMISSIONS, AS CO_2e				**117.1**

TABLE 3-2. Potential emissions for the proposed new Model LMS100 gas turbines GT3-GT7 during periods of startup and shutdown.

POLLUTANT		STARTUP/SHUTDOWN EMISSIONS										
		Startup		Shutdown		Normal Operation		Total		Estimated SU/SD per GT	Emissions per GT	Emissions GT3 - GT7 Combined
		minutes	lb per event	minutes	lb per event	minutes	lb per event	lb per event	lb per hour	events per year	ton/year	ton/year
Carbon Monoxide	CO	30	17.9	11	47.0	19	4.3	64.9	69.2	730	23.7	118.4
Nitrogen Oxides	NO_x	30	22.5	11	6.0	19	2.9	28.5	31.4	730	10.4	52.0
Particulate Matter	PM	30	2.7	11	1.0	19	1.7	3.7	5.4	730	1.3	6.7
Particulate Matter	PM_{10}	30	2.7	11	1.0	19	1.7	3.7	5.4	730	1.3	6.7
Particulate Matter	$PM_{2.5}$	30	2.7	11	1.0	19	1.7	3.7	5.4	730	1.3	6.7
Sulfur Dioxide	SO_2	30	0.3	11	0.1	19	0.2	0.4	0.6	730	0.1	0.7
Volatile Organic Cmds	VOC	30	5.8	11	4.9	19	0.8	10.7	11.5	730	3.9	19.5
Sulfuric Acid Mist	H_2SO_4	30	0.0	11	0.0	19	0.0	0.0	0.1	730	0.0	0.1
Fluorides (as HF)	HF	30	0.0	11	0.0	19	0.0	0.0	0.0	730	0.0	0.0
Lead	Pb	30	0.0	11	0.0	19	0.0	0.0	0.0	730	0.0	0.0006
Carbon Dioxide	CO_2	30	42,813	11	5,030	19	35,931	47,843	83,774	730	17,463	87,314
Greenhouse Gases	CO_2e	30	42,857	11	5,035	19	35,968	47,893	83,861	730	17,481	87,404

Footnotes

The fuel use during startup and shutdown is estimated based on 366 MMBtu per startup sequence and 43 MMBtu per shutdown sequence for a total of 409 MMBtu per 41 minute event. This equates to 1.49 x 10^6 MMBtu per year for all startup/shutdown events for all 5 turbines combined.

TABLE 3-3. Total potential emissions for the General Electric Model LMS100 gas turbines for all periods of operation, including startup and shutdown.

POLLUTANT		TOTAL POTENTIAL TO EMIT		
		Normal Operation GT3-GT7 ton/year	Startup / Shutdown GT3-GT7 ton/year	Total Emissions ton/year
Carbon Monoxide	CO	120.7	118.4	239.2
Nitrogen Oxides	NO_X	82.6	52.0	134.6
Particulate Matter	PM	48.2	6.7	54.9
Particulate Matter	PM_{10}	48.2	6.7	54.9
Particulate Matter	$PM_{2.5}$	48.2	6.7	54.9
Sulfur Dioxide	SO_2	5.2	0.7	5.9
Vol. Org. Compounds	VOC	23.6	19.5	43.1
Sulfuric Acid Mist	H_2SO_4	0.5	0.1	0.6
Fluorides (as HF)	HF	0.0	0.0	0.0
Lead	Pb	0.0043	0.0006	0.0049
Carbon Dioxide	CO_2	1,012,190	87,314	1,099,504
Greenhouse Gases	CO_2e	1,013,235	87,404	1,100,640

3.2 Hazardous Air Pollutant (HAP) Emissions.

Gas turbines are also a source of hazardous air pollutants (HAPs). However, natural gas-fired GTs are a relatively small source of HAPs. Potential HAP emissions for the proposed new GE Model LMS100 gas turbines are detailed in Table 3-4. The HAP emission factors are from the U.S. EPA's WebFIRE database and *Compilation of Air Pollutant Emission Factors, AP-42*, Volume 1: Stationary Point and Area Sources, Section 3.1, Stationary Gas Turbines for Electricity Generation.

Under 40 CFR Part 63, a major source of HAPs is any facility which emits, or has the potential to emit, of 10 tons per year or more of any single HAP, or 25 tons per year or more of all HAPs combined. From Table 3-4, the proposed new GTs will not have HAP emissions in excess of these major source levels. The Ocotillo Power Plant is currently a minor or area source of HAPs, and the proposed modification in this application will not change the minor HAP source status of this facility.

TABLE 3-4. Potential hazardous air pollutant (HAP) emission for GT3-GT7.

POLLUTANT	CAS No.	Emission Factor lb/mmBtu	Maximum Heat Input mmBtu/hr	Potential to Emit, each turbine tons/year	Potential to Emit, all 5 turbines tons/year
Acetaldehyde	75-07-0	4.0E-05	970	0.075	0.38
Acrolein	107-02-8	6.4E-06	970	0.012	0.06
Benzene	71-43-2	1.2E-05	970	0.023	0.11
1,3-Butadiene	106-99-0	4.3E-07	970	0.001	0.004
Ethylbenzene	100-41-4	3.2E-05	970	0.060	0.30
Formaldehyde	50-00-0	7.1E-04	970	1.335	6.67
Xylene	1330-20-7	6.4E-05	970	0.120	0.60
Naphthalene	91-20-3	1.3E-06	970	0.002	0.01
PAH		2.2E-06	970	0.004	0.02
Propylene oxide	75-56-9	2.9E-05	970	0.055	0.27
Toluene	108-88-3	1.3E-04	970	0.244	1.22
TOTAL				**1.93**	**9.66**

Footnotes

1. The emission factors are from the U.S. EPA's WebFIRE database. These factors are 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.
2. The emission factor for formaldehyde (CH_2O) emissions are based on the uncontrolled factor, i.e., without the additional reduction from oxidation catalysts.
3. Potential emissions in tons per year are based on the following fuel use limit for all 5 turbines combined:
   Annual heat input limit of 18,800,000 MMBtu/year (HHV)

3.3 Cooling Tower Emissions.

A new mechanical draft cooling tower will be installed as part of the Ocotillo Power Plant Modernization Project. The specifications for the new cooling tower are summarized in Table 3-5.

TABLE 3-5. Specifications for the new mechanical draft cooling tower.

Total Circulating Water Flow to Cooling Tower, gpm	61,500
Number of Cells	6
Maximum Total Dissolved Solids, ppm	8,000
Design Drift Loss, %	0.0005%
Release Height, feet	42.5
Tower Enclosure Height, feet	29
Exit Diameter per cell, feet	30

3.3.1 Cooling Tower Emissions.

In a mechanical draft cooling tower, the circulating cooling water is introduced into the top of the tower. As the water falls through the tower, an air flow is induced in a countercurrent flow using induced draft fans. A portion of the circulating water evaporates, cooling the remaining water. A small amount of the water is entrained in the induced air flow in the form of liquid phase droplets or mist. Mist eliminators or demisters are used at the outlet of cooling towers to reduce the amount of water droplets entrained in the air. The water droplets that pass through the demisters and are emitted to the atmosphere are called *drift loss*. When these droplets evaporate, the dissolved solids in the droplet become particulate matter. Therefore, cooling towers are sources of PM, PM_{10}, and $PM_{2.5}$ emissions.

Cooling tower PM emissions are calculated based on the circulating water flow rate, the total dissolved solids (TDS) in the circulating water, and the design drift loss according to the following AP-42 equation:

$$E = kQ(60\ \text{min/hr})(8.345\ \text{lb water/gal})\left[\frac{C_{TDS}}{10^6}\right]\left[\frac{\%DL}{100}\right] \qquad \textbf{\textit{Equation 1}}$$

Where,

	E	=	Particulate matter emissions, pounds per hour
	Q	=	Circulating water flow rate, gallons per minute = 61,500 gpm
	C_{TDS}	=	Circulating water total dissolved solids, parts per million = 8,000 ppm
	DL	=	Drift loss, % = 0.0005%
	k	=	particle size multiplier, dimensionless

The particle size multiplier “k” has been added to the AP-42 equation to calculate emissions for various PM size ranges, including PM_{10} and $PM_{2.5}$. AP-42 Section 13.4 presents data that suggests the PM_{10} fraction is 1% of the total PM emission rate, however no information is provided on $PM_{2.5}$ emissions.
Maricopa County had developed a “k” emission factor of 31.5% to convert total cooling tower PM emissions to PM_{10} emissions based on tests performed at the Gila Bend Power Plant. During the PSD permitting of the Hydrogen Energy California (HECA) project by the San Joaquin Valley Air Pollution Control District (SJVAPCD), the applicant used a ratio of 0.6 to convert cooling tower PM_{10} emissions to $PM_{2.5}$ emissions. This ratio was based on data in the California Emission Inventory Development and Reporting System (CEIDARS) data base, along with further documentation including an analysis of the emission data that formed the basis of the CEIDARS ratio, and discussions with various California Air Resources Board and EPA research staff. This PSD permit was reviewed and commented upon by the California Energy Commission and EPA Region 9, and these agencies accepted this factor for use in cooling tower $PM_{2.5}$ emission estimates.

Table 4 presents the calculated PM, PM_{10}, and $PM_{2.5}$ emissions for the cooling tower based on theparticle size multipliers of 0.315 for PM_{10} emissions and 0.189 (0.315 x 0.6) for $PM_{2.5}$ emissionswhich have been previously approved in PSD permitting actions.

TABLE 3-6. Potential emissions for the new mechanical draft cooling tower.

POLLUTANT		*Q* Flowrate	C_{TDS} Blowdown TDS Conc.	%DL Drift Loss	*k* Particle Size Multiplier	Potential to Emit	
		gallon/min	ppm	%		lb/hr	ton/yr
Particulate Matter	PM	61,500	8,000	0.0005%	1.00	1.23	5.39
Particulate Matter	PM_{10}	61,500	8,000	0.0005%	0.315	0.39	1.70
Particulate Matter	$PM_{2.5}$	61,500	8,000	0.0005%	0.189	0.23	1.02

3.4 Emergency Diesel Generator Emissions.

The new emergency generator diesel engines will be subject to the New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines in 40 CFR 60, Subpart IIII.
In accordance with 40 CFR §60.4201, manufacturers of new emergency stationary CI engines (defined as engines that are operated less than 100 hours per year for non-emergency use) must meet the following requirements:

> **§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?**
> (b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.
> (2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

The standards under 40 CFR 89.112 are listed in Table 3-7. The standards for emergency stationary CI engines are based on the Tier 2 standards. In addition, in accordance with 40 CFR §60.4207(b), both emergency and non-emergency engines must use diesel fuel that meets the requirements of 40 CFR §80.510(b) for nonroad diesel fuel. The sulfur content requirement for nonroad (NR) diesel fuel in 40 CFR §60.4207(b)(1)(i) is 15 ppm.

With this application, APS is proposing to install diesel generators which comply with the Tier 2 emission standards under 40 CFR §89.112. In addition, APS is proposing to limit the total operation of each generator to no more than 500 hours per year (100 hours testing and maintenance, and 400 hours for emergency use), based on a 12-month rolling average. These operating limits comply with the definition of emergency engines at Maricopa County Rule 324. The potential emissions for each 2.5 MW diesel-fired emergency electric generator, based on these proposed limitations, are summarized in Table 3-8.

TABLE 3-7. Emergency diesel engine standards under 40 CFR 60, Subpart IIII.

POLLUTANT		Emergency CI Engine Tier 2 Standards	
		g/kWhr	g/hp-hr
Carbon Monoxide	CO	3.5	2.61
Nitrogen Oxides	NO_x	6.4*	4.77*
Particulate Matter	PM	0.20	0.15
Non-Methane Hydrocarbons	NMHC	n/a	n/a

Footnotes

* The NO_x standards for Tier 2 engines are the sum of the NOx and NMHC.
The Tier 2 standards are for engines greater than 750 hp.

TABLE 3-8. Potential emissions for each 2.5 MW generator and for both generators combined.

POLLUTANT		Emission Factor	Power Output	Potential to Emit, Each Generator		Potential to Emit, Both Generators
		g/hp-hr	hp	lb/hr	ton/year	ton/year
Carbon Monoxide	CO	2.61	3,750	21.56	5.39	10.78
Nitrogen Oxides	NO_x	4.77	3,750	39.42	9.86	19.71
Particulate Matter	PM	0.15	3,750	1.24	0.31	0.62
Particulate Matter	PM_{10}	0.15	3,750	1.24	0.31	0.62
Particulate Matter	$PM_{2.5}$	0.15	3,750	1.24	0.31	0.62
Sulfur Dioxide	SO_2	0.0044	3,750	0.037	0.01	0.0184
Vol. Org. Cmpds	VOC	0.20	3,750	1.65	0.413	0.83
Sulfuric Acid Mist	H_2SO_4	4.4E-04	3,750	0.0037	0.00	0.00184
Flourides	F	7.9E-04	3,750	0.0065	0.00	0.00326
Lead	Pb	2.7E-05	3,750	0.0002	0.00	0.00011
Carbon Dioxide	CO_2	476.7	3,750	3,937.7	984.43	1,968.86
Greenhouse Gases	CO_2e	478.4	3,750	3,951.2	987.81	1,975.61

Footnotes

1. Potential emissions are based on 500 hours per year of total operation.
2. The CO, NOx, PM, and VOC emission rates are based on the Tier 2 engine standards in 40 CFR §89.112, and a maximum engine rating of 3,750 horsepower.
3. All PM emissions are also assumed to be PM_{10} and $PM_{2.5}$ emissions.
4. SO_2 emissions are based on a maximum fuel consumption rate of 175 gal/hr, and a sulfur content of 0.0015%.
5. Sulfuric acid mist emissions are based on 10% conversion of SO_2 to SO_3 in the flue gas.
6. Lead and fluoride emissions are based on the emission factor for oil combustion in the *U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42*, section 1.3, oil combustion, Tables 1.3-10 and 1.3-11., respectively, AND a maximum fuel oil consumption rate of 175 gallons per hour.
7. Emission factors for GHG emissions 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.

Diesel engines are also a source of hazardous air pollutants (HAPs). Potential HAP emissions are summarized in Table 3-9. The potential HAP emissions in Table 3-9 are based on emission factors from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, 5th Edition, Tables 3.4-3 and 3.4-4.

TABLE 3-9. Potential hazardous air pollutant (HAP) emissions for the emergency generators.

AIR POLLUTANT	CAS #	Emission Factor[1]	Heat Input	Potential to Emit, Each Generator		Potential to Emit, Both Generators
		lb/mmBtu	mmBtu/hr	lb/hr	ton/year	ton/year
Benzene	71-43-2	7.76E-04	24.3	0.0189	0.004719	0.00944
Toluene	108-88-3	2.81E-04	24.3	0.0068	0.001709	0.00342
Xylene	1330-20-7	1.93E-04	24.3	0.0047	0.001174	0.00235
Formaldehyde	50-00-0	7.89E-05	24.3	0.0019	0.000480	0.00096
Acetaldehyde	75-07-0	2.52E-05	24.3	0.0006	0.000153	0.00031
Acrolein	107-02-8	7.88E-06	24.3	0.0002	0.000048	0.00010
Naphthalene	91-20-3	1.30E-04	24.3	0.0032	0.000791	0.00158
Total PAH		2.12E-04	24.3	0.0052	0.001289	0.00258
Arsenic		1.10E-05	24.3	0.0003	0.000067	0.00013
Beryllium		3.10E-07	24.3	0.0000	0.000002	0.00000
Cadmium		4.80E-06	24.3	0.0001	0.000029	0.00006
Chromium		1.10E-05	24.3	0.0003	0.000067	0.00013
Manganese		1.40E-05	24.3	0.0003	0.000085	0.00017
Mercury		1.20E-06	24.3	0.0000	0.000007	0.00001
Nickel		4.60E-06	24.3	0.0001	0.000028	0.00006
Selenium		2.50E-05	24.3	0.0006	0.000152	0.00030
TOTAL					**0.0108**	**0.0216**

Footnotes

1. Emission factors are from the U.S. EPA's *Compilation of Air Pollutant Emission Factors*, AP-42, 5th Edition, Tables 3.4-3 and 3.4-4.
2. Potential emissions are based on limiting the total annual operation for each generator to 500 hours per year.
3. The maximum heat input rate is based on 175 gallons of fuel oil per hour.

3.5 Diesel Fuel Oil Storage Tanks.

The Project will include two 10,000 gallon diesel fuel oil storage tanks. Based on the operational limits for the diesel generators of 500 hours per year as proposed in this application and a maximum diesel engine fuel consumption rate of 175 gallons per hour, the maximum annual throughput for each tank would be 87,500 gallons per year. Potential VOC emissions based on the U.S. EPA’s TANKS program, Version 4.0.9d are calculated at 4.45 pounds per year for each tank, or total VOC emissions of 0.005 tons per year (rounded up to 0.01) for both tanks combined.

3.6 SF_6 Insulated Electrical Equipment.

The PSD program includes sulfur hexafluoride (SF_6) as a regulated GHG substance. The proposed circuit breakers which will be installed with the new LMS 100 GTs and emergency generators 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, since if too much gas leaked 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 also the International Electrotechnical Commission (IEC) maximum leak rate standard. Table 3-10 summarizes the potential SF_6 emissions for the planned equipment based on this leak rate.

TABLE 3-10. Potential fugitive sulfur hexafluoride (SF_6) emissions from the planned SF_6 insulated 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 Emissions, ton CO_2e /year
230 kV	9	135	0.50%	0.0030	23,900	72.6
69 kV	11	75	0.50%	0.0021	23,900	49.3
13.8 kV	5	35	0.50%	0.0004	23,900	10.5
TOTAL FUGITIVE EMISSIONS				**0.0046**	**23,900**	**132.3**

Footnotes

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

3.7 Natural Gas Piping Systems.

The PSD program also includes methane (CH_4) as a regulated GHG substance. Natural gas piping components including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections can leak and therefore result in small amounts of fugitive natural gas emissions. Since natural gas consists of from 70 to almost 100% methane, leaks in the natural gas piping can result in small amounts of methane emissions.

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 B13-1 summarizes the estimated fugitive methane emissions which are expected to result from a properly operated and maintained natural gas piping system at the Ocotillo Power Plant.

TABLE 3-11. Potential fugitive methane emissions from the natural gas piping systems and the equivalent GHG emissions.

Component Type	Component Count	Emission Factor scf / hour / component	Specific Volume scf / lb CH_4	Methane (CH_4) ton/year	CO_2e Factor[4]	Potential Emissions ton CO_2e /year
Valves	150	0.123	24.1	3.35	25	83.9
Connectors	125	0.017	24.1	0.39	25	9.7
Relief Valves	10	0.196	24.1	0.36	25	8.9
TOTAL PIPELINE FUGITIVE EMISSIONS				**4.10**	**25**	**102.4**

Footnotes

1. The emission factors are from 40 CFR Part 98, Table W-1A for onshore natural gas production, Western U.S.
2. The CO_2e factor is from 40 CFR 98, Subpart A, Table A-1.
3. 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.
4. Methane emissions are based on the worst-case assumption that the natural gas is 100% methane by volume.

3.8 Total Project Emissions.

Table 3-12 summarizes the total potential emissions for the Ocotillo Power Plant Modernization Project. Note that the requested allowable emissions are the same as the total potential emissions for all pollutants except NOx emissions. For NOx emissions, compliance with the requested allowable emission cap will be demonstrated using NOx CEMs for GT3-GT7 as required in 40 CFR Part 75, and hours of operation times the maximum potential hourly emission rate for the emergency generators.

TABLE 3-12. Summary of the total potential emissions for the Ocotillo Modernization Project.

POLLUTANT		Emissions, tons per year						
		GT3-GT7	GTCT	Emerg. Generators	Diesel Storage Tanks	SF_6 Insulated Equipment	Natural Gas Piping	Allowable TOTAL
Carbon Monoxide	CO	239.2		10.8				249.9
Nitrogen Oxides	NO_x	134.6		19.7				125.3
Particulate Matter	PM	54.9	5.4	0.6				60.9
Particulate Matter	PM_{10}	54.9	1.7	0.6				57.2
Particulate Matter	$PM_{2.5}$	54.9	1.0	0.6				56.5
Sulfur Dioxide	SO_2	5.9		0.0184				5.9
Vol Organic Cmpds	VOC	43.1		0.83	0.01			43.9
Sulfuric Acid Mist	H_2SO_4	0.6		0.00184				0.6
Fluorides (as HF)	HF	0.000		0.00326				0.00326
Lead	Pb	0.005		0.00011				0.00504
Carbon Dioxide	CO_2	1,099,504		1,968.9				1,101,473
Greenhouse Gases	CO_2e	1,100,640		1,975.6		132.3	102.4	1,102,850

Footnotes

Note that the requested allowable emissions are the same as the potential emissions based on the proposed operating and emission limits in this application for all pollutants except NO_x emissions. For NO_x emissions, compliance with the requested allowable emission cap will be demonstrated using NO_x Continuous Emission Monitoring Systems (CEMS) for GT3-GT7 as required in 40 CFR Part 75, and hours of operation times the maximum potential hourly emission rate for the emergency generators.

Chapter 4. Applicable Requirements

4.1 GE LMS 100 Gas Turbine Generators.

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

On July 6, 2006, the U.S. EPA published final rules revising the standards of performance for stationary combustion turbines under 40 CFR Part 60, Subpart KKKK. These standards are incorporated by reference in County Rule 360 § 301.84. In accordance with 40 CFR § 60.4315, the pollutants regulated by this subpart are nitrogen oxides (NO_X) and sulfur dioxide (SO_2).

4.1.1.1 Sulfur Dioxide (SO_2) Emission Limits.

For SO_2 emissions under 40 CFR § 60.4330, if your turbine is located in a continental area, you must either:

(1) Limit SO_2 emissions to 0.90 pounds per megawatt-hour gross output, or
(2) Not burn any fuel which contains emissions in excess of 0.060 lb SO_2/mmBtu heat input.

4.1.1.2 Nitrogen Oxides (NO_x) Emission Limits.

For NO_X emissions under 40 CFR § 60.4325, you must meet the emission limits specified in Table 1. Each of the proposed new natural gas-fired GE Model LMS100 simple cycle Gas turbines has a maximum design heat input capacity of 970 mmBtu per hour. The applicable standards in Table 1 are summarized below.

Excerpts from Table 1 to 40 CFR 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, modified, or reconstructed turbine firing natural gas.	Greater than 850 mmBtu/hr	15 ppm at 15 percent O_2 or 0.43 lb/MWh

4.1.1.3 General Compliance Requirement (40 CFR § 60.4333).

The simple cycle gas turbines, the SCR and oxidation catalysts 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.

4.1.1.4 NO_x Monitoring Requirements (40 CFR § 60.4335).

Subpart KKKK allows for a variety of acceptable monitoring methods to demonstrate compliance with the NO_x emission limits. APS has elected to install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_x monitor and a diluent gas (either oxygen (O_2) or carbon dioxide (CO_2)) monitor to determine the hourly NO_x emission rate in parts per million (ppm) corrected to 15% O_2. The CEMS will be installed and certified according to Appendix A of 40 CFR Part 75, and the relative accuracy test audit (RATA) of the CEMS will be performed on a lb/MMBtu basis. APS is requesting Maricopa County Air Quality Department approval to satisfy the 40 CFR 60 Subpart KKKK quality assurance (QA) plan requirements by implementing the QA program and plan described in Section 1 of Appendix B to Part 75. Subpart KKKK excess emissions will be identified according to 40 CFR §60.4350 procedures.

4.1.1.5 SO_2 Monitoring Requirements (40 CFR § 60.4360 and § 60.4365).

Subpart KKKK allows for a variety of 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 in continental areas is 20 grains of sulfur or less per 100 standard cubic feet. Because the new GTs will combust only pipeline quality natural gas with a typical SO2 emission rate of 0.0006 lb/MMBtu, this is the method that APS proposes to meet the Subpart KKKK SO_2 monitoring requirements.

4.1.1.6 Performance Tests (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 (§60.4415 provides the required ASTM test methods).

4.1.1.7 Reporting Requirements (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 performs 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.

4.1.2 Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 40 CFR 60, Subpart TTTT.

On August 3, 2015, the U.S. EPA announced the final Clean Power Plan which will regulate GHG emissions from new and existing power plants. 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 combustion turbines. The emission limitation for new natural gas-fired baseload combustion turbines is 1,000 pounds of CO_2 per MWh of gross energy output. In contrast to this efficiency-based performance standard for baseload units, the performance standard for non-baseload natural gas-fired combustion turbines is a fuel-based heat input standard of 120 pounds of CO_2 per mmBtu of heat input.

A non-baseload combustion turbine supplies less than its *design efficiency* times its *potential electric output* as net electric sales on a 3-year rolling average. These terms are defined as:

> *Design efficiency* means the rated overall net efficiency (e.g., electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (e.g., CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17) or ISO 2314:2009 Gas turbines – acceptance tests (incorporated by reference, see §60.17).
>
> *Potential electric output* means 33 percent or the base load rating design efficiency at the maximum electric production rate (e.g., CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 310,000 MWh 12 month potential electric output capacity).
>
> *Base load rating* means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, base load rating includes the heat input from duct burners.

The proposed LMS100 GTs have a design heat rate of 7,776 Btu/kWh (LHV) for the Singular Annular Combustor (SAC) and a gross electric output of 116.2 MW. Therefore, these units meet the applicability requirements for Subpart TTTT. The baseload rating of each GT is 904 mmBtu/hr (LHV), or 1,002 mmBtu/hr (HHV) at ISO conditions (not at site conditions), and the estimated design efficiency is 43.9%. For these GTs, the *potential electric output* is estimated as:

$$Potential\ electric\ output = 43.9\% \times \left(\frac{904\ mmBtu}{hr}\right)\left(\frac{10^6\ Btu}{mmBtu}\right)\left(\frac{kWh}{3{,}413\ Btu}\right)\left(\frac{MWh}{1{,}000\ kWh}\right)\left(\frac{8{,}760\ hr}{yr}\right)$$

$$Estimated\ Potential\ electric\ output\ = 1{,}018{,}593\ MWh$$

APS is proposing to limit operations of the LMS100 GTs so they are classified as non-baseload gas-fired units. The net electric sales for each LMS100 GT will be limited to no more than the design efficiency times the potential electric output on a 3-year rolling average. The design efficiency and potential electric output will be determined during the initial performance test using the methods referenced in 40 CFR 60 Subpart TTTT.

Since these GTs will be classified as non-baseload gas-fired units, the relevant 40 CFR 60 Subpart TTTT performance standard is a fuel-based heat input standard of 120 pounds of CO_2 per mmBtu of heat input; there are no Subpart TTTT monitoring or recordkeeping requirements (as discussed in 40 CFR 60.5520(d)(1), owners and operators of non-base load natural gas-fired combustion turbines will only need to maintain records that they burned only natural gas in the combustion turbine).

4.1.3 Federal Acid Rain Program, 40 CFR 72.6

The federal Acid Rain Program regulations in 40 CFR 72.6(a)(3)(i) state that a utility unit that is a new unit 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. A "utility unit" means a unit owned or operated by a utility that serves a generator in any State that produces electricity for sale. Finally, "Unit" means a fossil fuel-fired combustion device. Because the new gas turbine generators fire natural gas and produce electricity for sale, these new GTs are affected units under the federal Acid Rain Program. A copy of the Acid Rain Permit application has been submitted to EPA, and is included with this application as Appendix D.

4.1.4 National Emission Standards for Hazardous Air Pollutants.

Hazardous air pollutant (HAP) emissions are regulated under section 112 of the Clean Air Act. The U.S. EPA's National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (NESHAP), 40 CFR Part 63, Subpart YYYY, were published on March 5, 2004. Under 40 CFR § 63.6085, "you are subject to this subpart if you own or operate a stationary combustion turbine ***located at a major source of HAP emissions***." Under 40 CFR § 63.2, Major source means:

> ***Major source*** means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants, unless the Administrator establishes a lesser quantity, or in the case of radionuclides, different criteria from those specified in this sentence.

Potential emissions for the proposed new GE Model LMS100 gas turbines are detailed in Table 3-4. The HAP emission factors are from the U.S. EPA's WebFIRE database. These factors are 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. Based on the emissions in Table 3-4, these gas turbines will be a minor source of HAP emissions under 40 CFR § 63.2. Please note that the potential emissions for formaldehyde (CH_2O) emissions in Table 3-4 are based on the *uncontrolled* emission factor from the U.S. EPA's WebFIRE database.

Table 4-1 is a summary of potential HAP emissions for the existing General Electric Model 501 gas turbines. The potential emissions for these existing gas turbines are based on the operational limits for natural gas and distillate fuel oil operation as proposed in this application. Table 4-2 is a summary of the total potential HAP emissions for the Ocotillo Power Plant after the Modernization Project, based on the operational limits for the new and existing gas turbines as proposed in this application. From Table 4-2, total potential emissions of each individual HAP are less than 10 tons per year, and total potential emissions of all HAPs combined are also less than 25 tons per year. Therefore, the Ocotillo Power Plant will remain a minor source of HAP emissions after the Modernization Project and these new gas turbines will not be subject to the NESHAP requirements of 40 CFR Part 63, Subpart YYYY.

TABLE 4-1. Hazardous air pollutant (HAP) emissions for the existing gas turbines GT1 and GT2 based on the operational limits as proposed in this permit application.

POLLUTANT	CAS No.	Emission Factor lb/mmBtu	Maximum Heat Input mmBtu/hr	Potential to Emit, each turbine tons/year	Potential to Emit, GT1 and GT2 combined tons/year
Acetaldehyde	75-07-0	4.0E-05	915	0.029	0.06
Acrolein	107-02-8	6.4E-06	915	0.005	0.01
Benzene	71-43-2	1.2E-05	915	0.009	0.02
1,3-Butadiene	106-99-0	4.3E-07	915	0.000	0.00
Ethylbenzene	100-41-4	3.2E-05	915	0.023	0.05
Formaldehyde	50-00-0	7.1E-04	915	0.520	1.04
Xylene	1330-20-7	6.4E-05	915	0.047	0.09
Naphthalene	91-20-3	1.3E-06	915	0.001	0.00
PAH		2.2E-06	915	0.002	0.00
Propylene oxide	75-56-9	2.9E-05	915	0.021	0.04
Toluene	108-88-3	1.3E-04	915	0.095	0.19
TOTAL				**0.75**	**1.50**

Footnotes

1. The emission factors are 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.
2. The emission factor for formaldehyde (CH2O) emissions are based on the uncontrolled factor, i.e., without the additional reduction from oxidation catalysts.
3. Potential emissions in tons per year are based on the fuel use limit for both turbines combined of 2,928,000 MMBtu (HHV) per year

TABLE 4-2. Total hazardous air pollutant (HAP) emissions for the Ocotillo Power Plant after the Modernization Project.

POLLUTANT	CAS No.	Potential to Emit, tons per year			
		GT1-GT2	GT3-GT7	Diesel Generators	TOTAL
Acetaldehyde	75-07-0	0.059	0.376	0.00006	0.435
Acrolein	107-02-8	0.009	0.060	0.00002	0.070
Benzene	71-43-2	0.018	0.113	0.00189	0.132
1,3-Butadiene	106-99-0	0.001	0.004		0.005
Ethylbenzene	100-41-4	0.047	0.301		0.348
Formaldehyde	50-00-0	1.039	6.674	0.00019	7.714
Xylene	1330-20-7	0.094	0.602	0.00047	0.696
Naphthalene	91-20-3	0.002	0.012	0.00032	0.014
PAH		0.003	0.021	0.00052	0.024
Propylene oxide	75-56-9	0.042	0.273		0.315
Toluene	108-88-3	0.190	1.222	0.00068	1.413
Arsenic				0.00003	0.000
Beryllium				0.00000	0.000
Cadmium				0.00001	0.000
Chromium				0.00003	0.000
Manganese				0.00003	0.000
Mercury				0.00000	0.000
Nickel				0.00001	0.000
Selenium				0.00006	0.000
TOTAL		**1.50**	**9.66**	**0.0043**	**11.17**

4.2 Emergency Diesel Generators.

4.2.1 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines in 40 CFR 60, Subpart IIII.

The emergency engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. In accordance with 40 CFR §60.4201, manufacturers of new emergency stationary CI engines must meet the following:

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

In addition, in accordance with 40 CFR §60.4207(b), these engines must use diesel fuel that meets the requirements of 40 CFR §80.510(b) for nonroad diesel fuel. The sulfur content requirement for nonroad (NR) diesel fuel in 40 CFR §60.4207(b)(1)(i) is 15 ppm.

4.2.1.1 Emergency stationary internal combustion engine.

Under 40 CFR §60.4219, *Emergency stationary internal combustion engine* means:

> *Emergency stationary internal combustion engine* means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.
>
> (1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.
>
> (2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4211(f).
>
> (3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4211(f)(2)(ii) or (iii) and §60.4211(f)(3)(i).

The requirements for emergency operation under 40 §60.4211(f)(2)(ii) or (iii) and §60.4211(f)(3)(i) include the following:

> (f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than

emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

Note that because these engines will be manufactured to meet the Tier 2 emission standards for emergency engines under 40 CFR §60.4202, these engines are emergency stationary internal combustion engine, and will be required to meet the above emergency engine operating requirements, including an operating limit of no more than 100 hours of non-emergency operation per year.

In addition to these federal requirements, Maricopa County Rule 324 effectively limits the hours of operation to 100 hours for testing and maintenance, and 500 hours total including all emergency periods. Therefore, the potential emissions from the emergency generators have been based on 500 hours of operation per 12 month period.

4.2.2 National Emission Standards for Hazardous Air Pollutants.

These emergency generators will also be subject to the *National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines* (the RICE NESHAP) found in 40 CFR Part 63, Subpart ZZZZ. Under this subpart, a stationary RICE which is also subject to the NSPS standards in 40 CFR Part 60 AND which is located at an area source of HAP emissions must meet the NESHAP requirements of Subpart ZZZZ by complying with the NSPS requirements in 40 CFR 60, Subpart IIII. The engines as purchased will be certified to meet the requirements of 40 CFR Part 60, Subpart IIII.

4.3 New Source Review (NSR)

In the Clean Air Act Amendments of 1977, Congress established two preconstruction permitting programs which are commonly referred to as New Source Review. Title I, Part C of the Act includes the PREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY (PSD) program. Title I, Part D of the Clean Air Act includes the PLAN REQUIREMENTS FOR NONATTAINMENT AREAS. This program is often called the Nonattainment Area New Source Review (NANSR) program.

In accordance with the delegation agreement with US EPA dated Nov 22, 1993, MCAQD administers the PSD program pursuant to the requirements under 40 CFR §52.21. Therefore, the requirements of both 40 CFR §52.21 and County Rule 240 §308 are applicable to new major stationary sources and major modifications for attainment pollutants. This application is intended to meet both the requirements of 40 CFR 52.21 and County Rule 240 as applicable.

County Rule 240 §305 – 308 is applicable to new major stationary sources and major modifications at existing sources for pollutants for which the area is designated as nonattainment. The Ocotillo Power Plant is located in the Tempe, Maricopa County, Arizona. This location is currently designated as nonattainment for particulate matter less than 10 microns (PM_{10}) (classification of serious) and the 1997 and 2008 8-hour ozone standards (classification of marginal). The area is designated as a maintenance area for CO. The area is designated attainment/unclassifiable for all other criteria pollutants.

4.3.1 Prevention of Significant Deterioration of Air Quality (PSD).

The PSD program applies to new major sources or major modifications to existing sources for pollutants where the area is designated attainment/unclassifiable with National Ambient Air Quality Standards (NAAQS). The PSD program requires:

1. Installation of the Best Available Control Technology (BACT) for each regulated pollutant which exceeds the significant levels.
2. An air quality analysis to demonstrate that new emissions will not cause or contribute to a violation of any applicable NAAQS or PSD increment.
3. Class I area impacts analysis.
4. An additional impacts analysis.
5. Public involvement and participation.

4.3.2 Nonattainment Area New Source Review (NANSR).

NANSR applies to new major sources or major modifications at existing sources for criteria pollutants for which the area is designated nonattainment. NANSR requirements are customized for the nonattainment area. However, all NANSR programs require:

1. Installation of the Lowest Achievable Emission Rate (LAER) for each pollutant which exceeds the significant levels in the nonattainment area.
2. Emission offsets.
3. Alternatives Analysis
4. Public involvement and participation.

4.4 Major New Source Review (NSR) Applicability.

The New Source Review (NSR) programs are applicable to new major stationary sources and major modifications at existing sources. Because the existing Ocotillo Power Plant is a fossil fuel-fired steam electric plant with a heat input of more than 250 million Btu per hour, the major source thresholds under the PSD program are 100 tons per year of any pollutant (other than GHG emissions) and 100,000 tons per year of GHG emissions. Note that after the Ocotillo Modernization Project, the electrical generating units will consist of only simple-cycle gas turbines, and Ocotillo therefore will no longer be classified as a steam electric plant. Therefore, after the Project is completed, the major source thresholds under the PSD program will be 250 tons per year of any pollutant and 100,000 tons per year of GHG emissions. However, the Ocotillo Power Plant GHG emissions, both before and after the Project, will be greater than the major source threshold, and therefore ***the facility is classified as a PSD major source***.

The location of the Ocotillo Power Plant is currently classified as a serious nonattainment area for particulate matter equal to or less than 10 microns (PM_{10}), and is also classified as a marginal nonattainment area for ozone. The regulated pollutant for PM_{10} non-attainment areas is PM_{10}; the regulated pollutants for ozone nonattainment areas include NO_X and VOC emissions. The major source threshold levels under Maricopa County Rule 240, section 210.1 for stationary sources located in a nonattainment area are:

Pollutant Emitted	Nonattainment Pollutant And Classification	Quantity Threshold Tons/Year Or More
Carbon Monoxide (CO)	CO, Serious, with stationary sources as more than 25% of source inventory	50
Volatile Organic Compounds (VOC)	Ozone, Serious	50
VOC	Ozone, Severe	25
PM_{10}	PM_{10}, Serious	70
NO_X	Ozone, Serious	50
NO_X	Ozone, Severe	25

From the above, the major source threshold in serious nonattainment areas for PM_{10} is 70 tons per year, and the major source threshold for the marginal ozone nonattainment area pollutants (NO_X and VOC emissions) is 100 tons per year.

The current potential VOC emissions for the Ocotillo Power Plant are below the 100 tpy major nonattainment source threshold, therefore the source is a minor source for VOC emissions. The current potential PM_{10} and NO_x emissions from the Ocotillo Power Plant are greater than the major nonattainment source thresholds, therefore the Ocotillo Power Plant is an existing major stationary source for PM_{10} and ozone under the NANSR program. However, with this application, APS is proposing a plant-wide emission cap in accordance with County Rule 201, (EMISSION CAPS) which limits the total potential emissions for the entire Ocotillo Power Plant below the major source threshold level of 70 tons per year for PM_{10} emissions. Therefore, after the Project ***the facility will not be classified as a NANSR major source for PM_{10} and VOC emissions, and is classified as a NANSR major source for NOx emissions***.

4.4.1 Two-steps for determining NANSR and PSD applicability for modifications.

Determining the applicability of NANSR and PSD for modifications at an existing stationary major source is a two-step process in accordance with the provisions in 40 CFR § 52.21(a)(2)(iv)(a):

> (*a*) Except as otherwise provided in paragraphs (a)(2)(v) and (vi) of this section, and consistent with the definition of major modification contained in paragraph (b)(2) of this section, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—**a significant emissions increase** (as defined in paragraph (b)(40) of this section), and a **significant net emissions increase** (as defined in paragraphs (b)(3) and (b)(23) of this section). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

4.4.1.1 STEP 1: Project emission increases.

The first step is the calculation of the project emission increases in accordance with the methods specified in 40 CFR § 52.21(a)(2)(iv)(b) – (d). If the project emissions increase is less than the regulated NSR pollutant significant emission rate in 40 CFR § 52.21(b)(23)(i) and County Rule 100 §200.99, then the project is not a major modification and is not subject to review for that pollutant. The significant emission rates are summarized below. If the project causes a significant emissions increase, then the project is a major modification **only** if it also results in a significant net emissions increase.

TABLE 4-3. NANSR and PSD significant emission rates for the Ocotillo Power Plant, ton/yr.

Pollutant	PSD Significant Threshold
Carbon Monoxide	100
Nitrogen Oxides	40
Particulate Matter	25
PM_{10}	15
$PM_{2.5}$	10
Sulfur Dioxide	40
VOC	40
Lead	0.6
Fluorides (as HF)	3
Sulfuric Acid Mist	7
Greenhouse Gases	75,000*

*The threshold for determining whether GHGs are "subject to regulation" is pursuant to 40 CFR 52.21(b)(49).

4.4.1.2 STEP 2: Net Emissions Increase.

In accordance with 40 CFR § 52.21(a)(2)(iv)(a), if the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase. This second step in determining PSD applicability is commonly called *netting*. Netting involves accounting for source-wide contemporaneous and creditable emissions increases and decreases to demonstrate that the total changes to emissions at the source will not result in a significant net emission increase for that pollutant. *Net emissions increase* in 40 CFR § 52.21(b)(3)(i) and County Rule 100 § 200.66 means the amount by which the sum of the following exceeds zero:

(1) Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source; and

(2) Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between: 1) the date five years before construction on the particular change commences, and 2) The date that the increase from the particular change occurs.

With this application, APS is proposing to permanently retire the existing Ocotillo steam electric generating units 1 and 2 before commencing commercial operation of the proposed new gas turbines. The PSD and NANSR applicability determinations in this permit application are therefore based on the net emissions increases for this Project, considering the contemporaneous decreases in emissions from the permanent shutdown of the Ocotillo Steamers Units 1 and 2 which have been netted against the increase in emissions from the proposed new emissions units.

4.4.2 STEP 1: Project emission increases.

The first step in determining NANSR and PSD applicability for this Project is the calculation of the project emissions increases in accordance with the applicability procedures specified in 40 CFR § 52.21(a)(2)(iv)(d):

> (*d*) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (b)(4) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (b)(48)(iii) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

The total potential emissions for the Ocotillo Power Plant Modernization Project are compared to the NANSR and PSD significant emission rates in Table 4-4, for those pollutants for which the facility is classified as a major source. If the project emission increase is less than the pollutant significant emission rates in 40 CFR § 52.21(b)(23)(i), then the project is not a major modification and is not subject to PSD or NANSR review for that pollutant. From Table 4-4, the Project will not result in a significant emissions increase for sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and fluorides. Therefore, the Project is not a PSD major modification for these pollutants.

TABLE 4-4. Project emissions compared to the significant levels for the Ocotillo Modernization Project. All emissions in tons per year.

POLLUTANT		Requested Allowable Project Emissions	PSD/NANSR Significant Level	Over?
Carbon Monoxide	CO	249.9	100	YES
Nitrogen Oxides	NO_X	125.3	40	YES
Particulate Matter	PM	60.9	25	YES
Particulate Matter	$PM_{2.5}$	56.5	10	YES
Sulfur Dioxide	SO_2	5.9	40	NO
Sulfuric Acid Mist	H_2SO_4	0.6	7	NO
Fluorides (as HF)	HF	0.0	3	NO
Lead	Pb	0.005	0.6	NO
Carbon Dioxide	CO_2	1,101,473	75,000	YES
Greenhouse Gases	CO_2e	1,102,850	75,000	YES

Footnotes

Because the area is nonattainment for ozone and PM_{10}, and because the facility emissions are below the NAA major source thresholds for PM_{10} and VOC, the PM_{10} and VOC emissions do not need to be compared to significance levels.

4.4.3 STEP 2: Contemporaneous decreases in emissions from the permanent shutdown of the Ocotillo Steamers Units 1 and 2.

In accordance with 40 CFR § 52.21(a)(2)(iv)(a), if the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase. This second step results in the calculation of a net emissions increase.

4.4.3.1 Baseline Actual Emissions.

Under the definition of *net emissions increase* in 40 CFR § 52.21(b)(3)(i)(b), *baseline actual emissions* for calculating increases and decreases shall be determined as provided in 40 CFR § 52.21(b)(48), except that paragraphs (b)(48)(i)(c) and (b)(48)(ii)(d) of this section shall not apply. Under 40 CFR § 52.21(b)(48), for any existing electric utility steam generating unit baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project.

Note that County Rule 240 § 305.7 states that "A decrease in actual emissions shall be considered in determining the potential of a new source or modification to emit only to the extent that the Control Officer has not relied on it in issuing any permit or permit revision under these rules, or the State has not relied on it in demonstrating attainment or reasonable further progress." Under County Rule 100 § 200.3, actual emissions means "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a 2-year period that precedes the particular date and that is representative of normal source operation. The Control Officer may allow the use of a different time period upon a demonstration that it is more representative of normal source operation." In this NANSR/PSD applicability analysis, the baseline period for all pollutants is the 24-month period from March 2012 to February 2014, which meets the definition of both *baseline actual emissions* and *actual emissions*.

The baseline actual emissions for the Unit 1 and 2 steamers and associated cooling towers are presented in Appendix E, and summarized in Tables 4-5, 4-6, 4-7, and 4-8. The NO_x and CO_2 baseline actual emissions and the unit heat input expressed in MMBtu are based on the data from the Acid Rain Program CEMS. PM, PM_{10}, and $PM_{2.5}$ emissions are based on the heat input from the CEMS, and measured emission rates from stack tests. All PM emissions are also assumed to be PM_{10} and $PM_{2.5}$ emissions. All other baseline actual emissions are based on the heat input from the CEMS, and AP-42 emission factors.

4.4.4 Calculation of the Net Emissions Increase for the Project.

For the Ocotillo Power Plant Modernization Project, the calculation of a net emission increase as defined in 40 CFR § 52.21(b)(3)(i) means the amount by which the sum of the following exceeds zero:

(a) The increase in Project emissions; and

(b) Decreases in actual emissions from the Unit 1 and 2 steamers.

These are the only contemporaneous and creditable changes at the Ocotillo Power Plant. Because APS is proposing to permanently shut down the existing Unit 1 and 2 steamers and associated cooling towers prior to the initial operation of the new Project emissions units, the creditable decrease in actual emissions is equal to the baseline actual emissions for these emission units.

Table 4-9 is a calculation of the net emissions increase for the Ocotillo Power Plant Modernization Project. From Table 4-9, the Project will result in a significant emissions increase and a significant net emissions increase in carbon monoxide (CO), PM, $PM_{2.5}$, and greenhouse gas (GHG) emissions. The Project will not result in a significant net emissions increase for NO_x, SO_2, VOC, sulfuric acid mist, and fluoride emissions.

TABLE 4-5. Baseline actual emissions for the Ocotillo Power Plant Steamer Unit 1.

POLLUTANT		Baseline Heat Input mmBtu	Baseline Emission Rate lb/mmBtu	Baseline Actual Emissions ton/year
Carbon Monoxide	CO	609,861	0.0235	7.2
Nitrogen Oxides	NO_X	609,861	0.133	40.7
Particulate Matter	PM	609,861	0.0075	2.3
Particulate Matter	PM_{10}	609,861	0.0075	2.3
Particulate Matter	$PM_{2.5}$	609,861	0.0075	2.3
Sulfur Dioxide	SO_2	609,861	0.0006	0.2
Volatile Organic Cmpds	VOC	609,861	0.0055	1.7
Sulfuric Acid Mist	H_2SO_4	609,861	0.0000006	0.0002
Fluorides (as HF)	HF	609,861	0.0	0.0
Lead	Pb	609,861	0.0000005	0.0002
Carbon Dioxide	CO_2	609,861	118.9	36,243.5
Greenhouse Gases	CO_2e	609,861	119.0	36,279.0

TABLE 4-6. Baseline actual emissions for the Ocotillo Power Plant Steamer Unit 2.

POLLUTANT		Baseline Heat Input mmBtu	Baseline Emission Rate lb/mmBtu	Baseline Actual Emissions ton/year
Carbon Monoxide	CO	634,840	0.0235	7.5
Nitrogen Oxides	NO_X	634,840	0.142	45.2
Particulate Matter	PM	634,840	0.0075	2.4
Particulate Matter	PM_{10}	634,840	0.0075	2.4
Particulate Matter	$PM_{2.5}$	634,840	0.0075	2.4
Sulfur Dioxide	SO_2	634,840	0.0006	0.2
Volatile Organic Cmpds	VOC	634,840	0.0055	1.7
Sulfuric Acid Mist	H_2SO_4	634,840	0.0000006	0.0002
Fluorides (as HF)	HF	634,840	0.0	0.0
Lead	Pb	634,840	0.0000005	0.0002
Carbon Dioxide	CO_2	634,840	118.9	37,728.2
Greenhouse Gases	CO_2e	634,840	119.0	37,766.2

Footnotes for Tables 4-5 and 4-6

1. The baseline period for all pollutants is the 24-month period from March 2012 to February 2014.

TABLE 4-7. Total baseline actual emissions for the Ocotillo Power Plant Steamer Units 1 and 2.

POLLUTANT		Baseline Heat Input mmBtu	Baseline Emission Rate lb/mmBtu	Baseline Actual Emissions ton/year
Carbon Monoxide	CO	1,244,701	0.0235	14.6
Nitrogen Oxides	NO_X	1,244,701	0.138	85.9
Particulate Matter	PM	1,244,701	0.0075	4.6
Particulate Matter	PM_{10}	1,244,701	0.0075	4.6
Particulate Matter	$PM_{2.5}$	1,244,701	0.0075	4.6
Sulfur Dioxide	SO_2	1,244,701	0.0006	0.4
Volatile Organic Cmpds	VOC	1,244,701	0.0055	3.4
Sulfuric Acid Mist	H_2SO_4	1,244,701	0.0000006	0.0004
Fluorides (as HF)	HF	1,244,701	0.000000	0.0000
Lead	Pb	1,244,701	0.0000005	0.0003
Carbon Dioxide	CO_2	1,244,701	118.9	73,971.7
Greenhouse Gases	CO_2e	1,244,701	119.0	74,045.1

TABLE 4-8. Total baseline actual emissions for the Ocotillo Power Plant Steamer Units 1 and 2 and the associated cooling towers.

POLLUTANT		Unit 1 ton/year	Unit 2 ton/year	Cooling Towers ton/year	Baseline Actual Emissions ton/year
Carbon Monoxide	CO	7.2	7.5		14.6
Nitrogen Oxides	NO_X	40.7	45.2		85.9
Particulate Matter	PM	2.3	2.4	3.3	8.0
Particulate Matter	PM_{10}	2.3	2.4	1.0	5.7
Particulate Matter	$PM_{2.5}$	2.3	2.4	0.6	5.3
Sulfur Dioxide	SO_2	0.2	0.2		0.4
Volatile Organic Cmpds	VOC	1.7	1.7		3.4
Sulfuric Acid Mist	H_2SO_4	0.00018	0.00019		0.0004
Fluorides (as HF)	HF	0.00000	0.00000		0.0000
Lead	Pb	0.00015	0.00016		0.0003
Carbon Dioxide	CO_2	36,243.5	37,728.2		73,971.7
Greenhouse Gases	CO_2e	36,279.0	37,766.2		74,045.1

TABLE 4-9. Net emissions increase and PSD applicability. All emissions are tons per year.

POLLUTANT		Requested Allowable Project Emissions	Creditable Emission Decreases	Net Emission Increase	Significant Level	Over?
Carbon Monoxide	CO	249.9	14.6	235.3	100	**YES**
Nitrogen Oxides	NO_X	125.3	85.9	39.4	40	**NO**
Particulate Matter	PM	60.9	8.0	52.9	25	**YES**
Particulate Matter	$PM_{2.5}$	56.5	5.3	51.2	10	**YES**
Sulfur Dioxide	SO_2	5.9	0.4	5.5	40	**NO**
Sulfuric Acid Mist	H_2SO_4	0.6	0.0	0.6	7	**NO**
Fluorides (as HF)	HF	0.001	0.0	0.0	3	**NO**
Lead	Pb	0.005	0.0003	0.005	0.6	**NO**
Carbon Dioxide	CO_2	1,101,473	73,972	1,027,501	75,000	**YES**
Greenhouse Gases	CO_2e	1,102,850	74,045	1,028,805	75,000	**YES**

Footnotes

Because the area is nonattainment for ozone and PM_{10}, and because the facility emissions are below the NAA major source thresholds for PM_{10} and VOC, the PM_{10} and VOC emissions do not need to be compared to significance levels.

4.4.5 Conclusions Regarding PSD Applicability.

Based on the total potential emissions for the Ocotillo Power Plant Modernization Project as proposed in this application, the Project will not result in a significant emissions increase for sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and fluorides. The project emission increases exceed the PSD significant increase levels for nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM), $PM_{2.5}$, and greenhouse gas (GHG) emissions. However, based on the proposed permanent shutdown and retirement of the Ocotillo Steamer Units 1 and 2, the Project will result in a significant net emissions increase only for carbon monoxide (CO), PM, $PM_{2.5}$, and greenhouse gas (GHG) emissions. The Project will not result in a significant net emissions increase for nitrogen oxides (NO_x), SO_2, VOC, sulfuric acid mist, and fluoride emissions, and therefore the Project does not trigger PSD review for these pollutants. Finally, because the Ocotillo Power Plant is located in an area designated as nonattainment for PM_{10} emissions, the Project is not subject to PSD review for PM_{10} emissions.

4.4.6 Conclusions Regarding Nonattainment Area New Source Review Applicability.

APS is proposing a PM_{10} emission cap that will limit the total potential emissions for the entire Ocotillo Power Plant below the major source threshold level of 70 tons per year for PM_{10}. In addition, the total potential VOC emissions for the entire Ocotillo Power Plant are below the major source threshold level of 100 tons per year for VOC. Therefore, the NANSR requirements do not apply to PM10 or VOC.

Because the facility is a NANSR major source for NOx, the net emissions increase for NO_x emissions must be less than the significant increase level of 40 tons per year for the Project to not be subject to NANSR requirements. As shown in Table 4-8, the net emissions increase for NO_x and VOC emissions for the Project are less than the significant increase level of 40 tons per year for each pollutant.

Based on the proposed emission limits in this permit application, this Project is not subject to review for any nonattainment area pollutants.

4.5 Minor NSR Requirements.

Based on the proposed limits in this application, the Project will not result in a significant net emissions increase for NO_x or VOC emissions. Therefore, the Project is not subject to the PSD program. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of NO_X or VOC emissions. Because the GTs would have maximum annual NO_x and VOC emissions which exceed these thresholds, this air pollution control construction permit application includes BACT analyses for NO_x and VOC emissions. These analyses are included in Appendix B of this application.

4.6 Title V Revision.

The proposed Ocotillo Modernization Project meets the criteria for requiring a Significant Permit Revision as described in Rule 210 section 406. Therefore, this permit application includes all information required by Rule 210, Section 406, Rule 240 and other applicable Maricopa Rules.

4.7 Other Applicable Maricopa County Air Regulations.

Rule 245 contains continuous monitoring requirements for various sources, including fossil fuel-fired steam generators. However, the Project emission units are not steam generators. Additionally, per Subsection 306.1, sources are exempted from the requirements if they are subject to an NSPS (which is the case for the Project GTs). Therefore, Rule 245 is not applicable (Rule 245 monitoring requirements are effectively subsumed into the applicable NSPS and Acid Rain monitoring requirements).

Performance and compliance testing requirements are contained in Rule 270. The rule establishes the requirements for testing criteria, conditions, and facilities, as well as reporting of performance test results. The Maricopa County Control Officer has the authority to require testing in accordance with Rule 270, and so these provisions may be an applicable requirement in the permit.

Rule 300 requirements apply to visible emissions resulting from the discharge of any air contaminant with certain exceptions (i.e., except for visible emissions from start-up, shutdown, or unavoidable combustion irregularities as described in section 302.1). The applicable opacity limit is 20%. Rule 300 also contains opacity compliance monitoring provisions.

Rule 311 establishes PM emissions limits for process industries. Section 304 of Rule 311 contains specific PM emission limitations for fuel burning operations, which are applicable to the proposed project. The proposed emission limits are below the Rule 311 limitations. Rule 311 has provisions for Operation and Maintenance (O&M) plans at section 306. Since an approved emission control system is not required for particulate matter emissions from any unit that is part of the proposed project, these

O&M requirements are not applicable. The recordkeeping and reporting requirements of Rule 311 are listed in section 502. Since an approved emission control system is not required for particulate matter emissions, the only applicable recordkeeping requirement is to maintain records of the total amount of fuel used on a daily basis.

Rule 322 establishes emissions limits for power plants. Section 301.1 requires that combustion equipment fire only natural gas except when firing emergency fuel. Section 302.1 limits visible emissions from any source to 20% opacity except for brief periods as provided in section 302.2. Section 303 requires that fuel oil burned alone or in combination with other fuels be low sulfur fuel oil (less than or equal to 0.05% sulfur). Section 304 limits NO_x emissions to 155 ppmv at 15% O_2 for the GTs when burning gaseous fuels. Section 305 limits CO emissions to 400 ppmv at 15% O_2 for the GTs. (Both the NO_x and CO limits are based on a 30-day rolling average when using CEMS.) For the cooling tower, section 301.4 requires the use of a drift eliminator, and the concentration of Total Dissolved Solids (TDS) multiplied by the percentage of drift rate shall not exceed 20. (The proposed TDS is 8,000 ppm and the drift loss is 0.0005%; therefore the product is 4.) Thus, the proposed emission limits in this permit application and proposed monitoring and recordkeeping comply with Rule 322 requirements.

Rule 324 establishes emissions limits for stationary internal combustion (IC) engines. Section 301 requires that the diesel fuel oil may contain no more than 0.05% sulfur by weight. Section 302 requires the use of good combustion practices and tuning as recommended by the manufacturer. Section 303 limits visible emissions to 20% opacity. Finally section 304 establishes additional limits for IC engines larger than 250 horsepower, including a NOx limit of 6.9 g/bhp-hr, a PM limit of 0.40 g/bhp-hr, and a CO limit of 1,000 ppmdv. In addition, the definition of emergency generator in Rule 324 effectively limits the hours of operation to 100 hours for testing and maintenance, and 500 hours total including all emergency periods. APS has requested these operating limits as part of this permit application.

Rule 32F establishes maximum SO_2 ambient concentrations, and an air quality analysis will be performed to demonstrate compliance with this rule.

Compliance Assurance Monitoring (CAM) requirements, implementing the enhanced monitoring mandate in Section 114(a)(3) of the Clean Air Act, are codified at 40 CFR Part 64. APS is proposing to install CEMS both for CO and for NO_x. The CO CEMS will meet the requirements set forth at 40 CFR 60.13; the NO_x CEMS will meet the requirements set forth at 40 CFR Part 75. Thus, as specified at Section 64.3(d)(2) of the CAM rule, these CEMS will satisfy the monitoring design requirements in the CAM rule.

Chapter 5. Proposed Control Technologies and Emission Limits.

Appendix B of this permit application presents the control technology analysis for the proposed simple-cycle GTs, the cooling tower, the emergency engines, the diesel fuel oil storage tank, the SF_6 insulated electrical equipment, and the natural gas piping systems. The analyses address both the BACT requirements under the PSD rules, as well as the "County BACT" analysis required under Maricopa County Air Pollution Control Regulations, Rule 241, Section 301.1.

For the PSD BACT analysis for the pollutants CO, PM, $PM_{2.5}$, and GHG, the "top-down" approach was used as recommended by EPA. 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 Maricopa County BACT analysis for the pollutants NO_x and VOC was performed in accordance with the Air Quality Department's memorandum "REQUIREMENTS, PROCEDURES AND GUIDANCE IN SELECTING BACT and RACT", revised July, 2010. In Section 8 of that memorandum, the guidance states: "To streamline the BACT selection process, the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above." Based on this guidance, the Ocotillo control technology analysis considered recent NO_X and VOC BACT determinations in California for similar simple-cycle gas turbines.

Table 5-1 summarizes the proposed BACT emission limits that are described in Appendix B of this permit application for the proposed new LMS100 gas turbines. These BACT emissions will be achieved through the use of high efficiency simple-cycle gas turbines, good combustion practices, water injection in combination with selective catalytic reduction (SCR), oxidation catalysts, and combustion of pipeline quality natural gas. Table 5-2 summarizes the proposed BACT emission limits for the proposed new emergency diesel generators. Table 5-3 summarizes the proposed BACT conditions for the SF6 insulated equipment and natural gas pipeline systems.

TABLE 5-1. BACT emission limits for the Ocotillo Modernization Project gas turbines.

Pollutant	PSD or County BACT Requirement	Proposed BACT Emission Limit
Carbon Monoxide (CO)	PSD BACT	6.0 ppmdv at 15% O_2, based on a 3-hour average.
Nitrogen Oxides (NO_x)	County BACT	2.5 ppmdv at 15% O_2, based on a 3-hour average.
Particulate Matter PM and $PM_{2.5}$	PSD BACT	5.4 pounds per hour, combined filterable and condensable.
Volatile Organic Compounds (VOC)	County BACT	2 ppmdv at 15% O_2, based on a 3-hour average.
Greenhouse Gases (CO_2e)	PSD BACT	1. The net electric sales for each LMS100 GT will be limited to no more than the design efficiency times the potential electric output on a 3-year rolling average. The design efficiency and potential electric output will be determined during the initial performance test using the methods referenced in 40 CFR 60 Subpart TTTT. 2. Achieve an initial heat rate of no more than 8,742 Btu/kWhr of gross electric output at 100% load. 3. 1,460 lb CO_2/MWh of gross electric output, based on a 12-operating month rolling average. 4. Prepare and follow a Maintenance Plan.

TABLE 5-2. BACT emission limits for the Ocotillo Modernization Project emergency generators.

Pollutant	PSD or County BACT Requirement	Proposed BACT Emission Limit
Carbon Monoxide (CO)	PSD BACT	Tier 2 Emission Standard of 2.61 g CO/hp-hr.
Nitrogen Oxides (NO_x)	County BACT	Tier 2 Emission Standard of 4.77 g NO_x/hp-hr.
Particulate Matter PM and $PM_{2.5}$	PSD BACT	Tier 2 Emission Standard of 0.15 g PM/hp-hr.
Volatile Organic Compounds (VOC)	County BACT	0.20 g NMHC/hp-hr.
Greenhouse Gases (CO_2e)	PSD BACT	1. Carbon dioxide (CO_2) emissions from each diesel generator may not exceed 197.6 tons per year. 2. The operation of each generator may not exceed 500 hours per year.

TABLE 5-3. BACT emission limits for the Ocotillo Modernization Project SF_6 insulated electrical equipment and natural gas piping systems.

Emission Unit	PSD or County BACT Requirement	Proposed BACT Emission Limit
SF_6 Insulated Electrical Equipment	PSD BACT	The Permittee shall install, operate, and maintain enclosed-pressure SF_6 circuit breakers with a maximum annual leakage rate of 0.5% by weight.
Natural Gas Piping Systems	PSD BACT	1. The permittee shall implement an auditory /visual /olfactory (AVO) monitoring program for detecting leaks in the natural gas piping components. 2. AVO monitoring shall be performed in accordance with a written monitoring program.

Chapter 6. Dispersion Modeling Analysis.

Section 4 of this permit application has demonstrated that PSD permitting requirements are only triggered for the criteria pollutants CO and $PM_{2.5}$. Because the Ocotillo Power Plant is located in an area designated as non-attainment for PM_{10} and ozone, the Project is not subject to PSD air quality analysis requirements for PM_{10}, nor VOC and NO_X as precursors. Therefore, a PSD air quality impact analysis is only required for CO and $PM_{2.5}$. The analysis includes the following components:

- Identification of existing monitoring data that fulfills the PSD pre-construction monitoring requirements;
- An analysis of the background monitoring concentrations relative to the NAAQS to confirm that significant impact levels (SILs) can be used in the modeling analysis;
- Dispersion modeling to determine whether ambient impacts caused by the Project would exceed modeling SILs;
- For each pollutant with impacts that exceed the SILs, a refined dispersion analysis to assess the effect of the proposed project and other sources on compliance with the National Ambient Air Quality Standards (NAAQS);
- An assessment of the proposed Project's impacts to the $PM_{2.5}$ PSD increments;
- An assessment of the proposed Project's impacts to soils, vegetation, and visibility;
- An assessment of regional population growth and associated emissions that may be caused by the proposed Project; and
- An assessment of the proposed Project's potential to affect increments, visibility, or other air quality related values (AQRVs) in Class I areas.

In addition to these PSD required air quality analyses, MCAQD has requested facility-wide NAAQS analyses for the criteria pollutants NO_2 and SO_2 to assess the Project's air quality impacts, and to address MCAQD Rule 32F. Because Maricopa County is designated a nonattainment area for PM_{10}, air quality analyses are not required for that pollutant under either the PSD rules nor MCAQD policy.

An air quality analysis protocol was developed for MCAQD review and approval. Refer to Appendix F of this permit application for the Air Quality Analysis Report that contains the air quality impact analyses. This report documents that the Project will not cause or contribute to an exceedance of any relevant NAAQS or PSD increment, and will not adversely affect soils, vegeatation, visibility, or any AQRV in Class I areas.

Chapter 7. Endangered Species and Historic Preservation Analyses.

7.1 Endangered Species Act.

Federally-issued PSD construction permits (or permits issued by a state or local agency pursuant to a delegation of PSD authority from EPA) are considered to be subject to the requirements of the Endangered Species Act of 1973 (ESA). If the permitting action may affect a federally-listed species or critical habitat, Section 7 of the ESA sets up a procedure for consultation between EPA and U.S. Fish and Wildlife Service (FWS) and/or the National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NMFS). The ESA regulations require permitting agencies and the applicant to participate in a preliminary "informal" consultation process. The applicant must obtain a list of endangered or threatened species and critical habitat in the area of the proposed project. If there are protected resources that could be affected by the project, the applicant must use this information to prepare a Biological Assessment for the project and provide a copy with the PSD application. After the initial consultation between the permitting agency and FWS, the FWS or NMFS may provide written concurrence that the proposed permitting action is not likely to adversely affect listed species or other critical habitat.

A study of special status species and species of concern was conducted as part of the Certificate of Environmental Compatibility (CEC) for the Ocotillo Modernization Project. This study is included in Appendix G of this application. The applicable laws for which this study was conducted include the Endangered Species Act (ESA), The Bald and Golden Eagle Protection Act (BGEPA), the Wildlife of Special Concern and Arizona Protected Plants, and the Migratory Bird Treat Act (MBTA).

The study notes that the Ocotillo Power Plant site is currently an industrialized area and does not have habitat to support special status species or species of special concern. The new GTs would be installed on the west side of the Ocotillo site. This area has been previously disturbed and holds abandoned tanks that will be removed. The species of special concern in the area occur in native communities and urban areas adjacent to the Ocotillo site which would not be impacted by the project because ground disturbing impacts would be confined to the existing industrialized Ocotillo site. And because operations after the project would remain similar to the current operations, native habitats, plants, and wildlife species outside the Ocotillo site would not experience other additional impacts. Therefore, protected species and resources will not be affected by the Project.

7.2 Historic Preservation Act.

Section 106 of the National Historic Preservation Act (NHPA) requires EPA, prior to the issuance of any license or permit, to take into account the effects of its actions on historic properties and afford the Advisory Council on Historic Preservation (the Council) a reasonable opportunity to comment with regard to such undertakings. Under the Council's implementing regulations at 36 CFR Part 800, section 106, consultation is required for all undertakings that have the potential to affect historic properties. Section l06 consultations assess whether historic properties exist within an undertakings area of potential effect and, if so, whether the undertaking will adversely affect such properties. Consultation is generally with relevant state and tribal historic preservation authorities in the first instance, with opportunities for direct Council involvement in certain circumstances. As part of the permit application, the applicant should furnish its assessment of whether historic properties exist within the source's area of potential effect. If so and there are adverse effects to such properties caused by the project, the application should also discuss ways to avoid, minimize, or mitigate such effects. The term "historic properties" means prehistoric or historic districts, sites, buildings, structures, or objects included in, or eligible for inclusion in, the National Register of Historic Places maintained by the Department of the Interior. Historic properties include properties of traditional religious and cultural importance to an Indian Tribe or Native Hawaiian organization.

The Ocotillo Power Plant site is currently an industrialized area without historic properties on the plant site. A study of historical properties and structures was conducted as part of the Certificate of Environmental Compatibility (CEC) for the Ocotillo Modernization Project. This study is included in Appendix H of this application. The new GTs would be installed on the west side of the Ocotillo site, an area that has been previously disturbed and holds abandoned tanks that will be removed. All ground disturbing impacts would be confined to the existing industrialized Ocotillo site. The maximum excavation depth expected for the new Project equipment is 20 feet below ground surface. The overall conclusion from the NHPA analysis is that historical properties will not be adversely affected by the project.

Chapter 8. Environmental Justice.

Executive Order 12898, *Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations* states "each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations." Consistent with the Agency's Environmental Justice (EJ) commitment, before issuing a PSD permit the EPA Regional Office should examine any superficially plausible claim that the facility seeking the PSD permit will disproportionately affect a minority, low-income, or tribal community.

EPA has developed an EJ mapping and screening tool called EJSCREEN (http://www2.epa.gov/ejscreen). It is based on nationally consistent data and an approach that combines environmental and demographic indicators in maps and reports. EJSCREEN can be used to determine the locations of nearby minority and low-income communities using the Demographic Index, which considers the percentage of low-income and minority populations in each Census block group.

EJSCREEN has been used to identify EJ communities near the Ocotillo Power Plant. Appendix I presents the EJ analysis for this project, which compares predicted air quality impacts to the health standards and determines the locations of maximum project impacts. This analysis demonstrates that the Project will not result in disproportionately high and adverse human health or environmental effects with respect to minority or low-income populations residing near the proposed Project, or on the community as a whole.

Chapter 9. Proposed Permit Conditions

Tables 7-1 through 7-4 summarize the proposed enforceable emission limits for the Ocotillo Modernization Project gas turbines (GTs) and cooling tower. The proposed permit compliance requirements are described below, and consist of: CEM data for NO_x, CO, and carbon dioxide (CO_2) emissions; fuel use data; PM_{10}, $PM_{2.5}$, and VOC emission factors for the GTs derived from the most recent stack test data; fuel specification data from the natural gas pipeline supplier; data on the number of GT startup/shutdown events; hours of operation of the cooling towers and emergency generators.

TABLE 7-1. Proposed rolling 12-month Average Limits (tons per year).

Emissions Unit(s)	SO_2	NOx	CO	PM_{10}	$PM_{2.5}$	VOC	CO_2
GT3 - GT7	5.9	125.3	239.2	63.0	54.9	43.1	1,099,504
Emergency Generators	0.02		10.8		0.6	0.83	1,969
GTCT	NA	NA	NA		1.5	NA	NA
GT1-2	NA	NA	NA		NA	NA	NA

TABLE 7-2. Hourly Emission Limits for the new gas turbines GT3 - GT7 when turbines operate during periods other than startup/shutdown and tuning/testing mode, lb/hour, 3-hour average).

Emissions Unit(s)	SO_2	NOx	CO	PM_{10}	$PM_{2.5}$	VOC	CO_2e
GT3-GT7 individually	0.6	9.3	13.5	5.4	5.4	2.6	NA
GTCT	NA	NA	NA	0.39	0.23	NA	NA

TABLE 7-3. Hourly emission limits for Units GT3 - GT7 during periods when gas turbines operate in startup/shutdown (lb/hour, 1-hour average).

	NOx	CO	VOC
GT3-GT7	31.4	69.2	11.5

TABLE 7-4. Additional concentration or rate emission limits.

Emission Unit or Device	NO_x	CO	PM_{10} Total	$PM_{2.5}$ Total	VOC	CO_2e	Other
GT3 - GT7 during Normal Operation Other than Startup/ Shutdown or Tuning/Testing Mode	2.5 ppmdv at 15% O_2, based on a 3-hour average	6.0 ppmdv at 15% O_2, based on a 3-hour average	5.4 lbs/hr, based on a 3-hour average.	5.4 lbs/hr, based on a 3-hour average.	2 ppmdv at 15% O_2, based on a 3-hour average.	1,460 lbs CO_2/MWh gross output, based on a 12-operating month rolling average.	Ammonia 10 ppmdv, Based on a 24-hour rolling average
Cooling Tower	NA	NA	Drift eliminators limiting drift to 0.0005% and Total Dissolved Solids (TDS) content of circulating cooling water less than 8,000 ppm	Drift eliminators limiting drift to 0.0005% and Total Dissolved Solids (TDS) content of circulating cooling water less than 8,000 ppm	NA	NA	NA
Pipeline Natural Gas Fuel Sulfur Content	NA	NA	NA	NA	NA	NA	NA

The following notes and compliance methods apply to Tables 8-1 through 8-4:

a) NA (Not Applicable) means that the device does not emit the indicated pollutant or there is no relevant emission limit.

b) Startup is defined as the period between when a unit is initially started and fuel flow is indicated and ending 30 minutes later.

c) "Shutdown" is defined as the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased.

d) The rolling 12- month limits shall be calculated monthly using the data from the most recent 12 calendar months, with a new 12-month period beginning on the first day of each calendar month.

e) The 3-hour rolling average limits shall be calculated hourly using the data from the most recent 3 hours, with a new 3-hour period beginning each hour.

f) NO_x emissions during all operations of GT3 through GT7 shall be calculated using CEMS data in accordance with 40 CFR Part 75, Appendix F.

g) CO emissions from Units GT1 through GT7 shall be calculated from CEMS data.

h) PM_{10} and VOC emissions during all operations of Units GT3 through GT7 shall be calculated using monitored fuel flow and emission factors from the most recent performance test for each unit, unless an alternative emission factor can be demonstrated to the satisfaction of the Control Officer and the Administrator to be more representative of emissions.

i) PM_{10} and VOC emissions during all operations of GT1 and GT2 shall be calculated using monitored fuel flow and emission factors from the U.S. EPA document AP-42, unless an alternative emission factor can be demonstrated to the satisfaction of the Control Officer and the Administrator to be more representative of emissions.

j) PM_{10} emissions from the Cooling Towers (GTCT) shall be calculated from the following equation: PM_{10} Emissions (tons/yr) = Total Recirculation Rate (gallons/minute) * TDS Concentration (milligrams/liter) * Operating Hours * 3.94E-13;

k) SO_2 emissions from all units shall be calculated from fuel usage during all operations and the sulfur content of the fuel as determined as specified in this permit.

l) Emissions from the emergency generators will be calculated using recorded operating hours and the maximum allowable Tier 2 standard emission rates.

m) Unless otherwise stated, the PM_{10} emission limits include both solid (filterable) and condensable particulate matter. Filterable PM_{10} is measured with 40 CFR Part 60 Appendix A Method 5. Condensable particulate matter is measured with 40 CFR 60 Appendix A Method 202.

9.1 Operational Requirements for Units GT-3 through GT-7.

The following operational and monitoring and recordkeeping requirements are also proposed.

1) The Permittee shall operate and maintain Selective Catalytic Reduction (SRC) catalysts on Units GT3 through GT7. The Permittee shall maintain an Operations and Maintenance (O&M) Plan for the SCRs required by these Permit Conditions. The Plan shall be in a format acceptable to the Department and shall specify the procedures used to maintain the SCRs. The Permittee shall at all times during normal operation comply with the latest version of the O&M Plan approved in writing by the Control Officer. [County Rules 210 §302.1.b and 322 §306.2 and §306.3]

2) The Permittee shall operate and maintain CO Oxidation Emission Control Systems (OX-ECS) on GT3 through GT7. The Permittee shall maintain an O&M Plan for the OX-ECS required by these Permit Conditions. The Plan shall be in a format acceptable to the Department and shall specify the procedures used to maintain the OX-ECS. The Permittee shall comply at all times with the most recent version of the O&M Plan that has been approved in writing by the Control Officer. [County Rules 210 §302.1.b and 322 §306.2 and §306.3]

3) The Permittee shall use operational practices recommended by the manufacturer and parametric monitoring to ensure good combustion control. [County Rule 322 §301.3]

4) The Permittee shall not combust any fuel other than natural gas in units GT3 through GT7.

5) The total number of hours in startup and shutdown mode for GT3 through GT7 combined shall not exceed 2,490 hours averaged over any consecutive 12-month period.

6) The net electric sales for each GT will be limited to no more than the design efficiency times the potential electric output on a 3-year rolling average. The design efficiency and potential electric output will be determined during the initial performance test using the methods referenced in 40 CFR 60 Subpart TTTT.

9.2 Monitoring and Recordkeeping Facility-Wide Requirements.

The Permittee shall hourly monitor and record the hours of operation and operating mode (startup, shutdown, or normal) of Units GT3 through GT7; exhaust temperature prior to entering the SCR systems and the OX-ECS; the amount of natural gas combusted in individual Units GT3 through GT7; and the actual heat input of Units GT3 through GT7. The Permittee may monitor the combined fuel usage in Units GT3 through GT7 instead of individually. The Permittee shall monthly calculate and record the emissions from Units GT1 and GT2, GT3 through GT7, and the Cooling Tower and shall monthly compare the calculated emissions to the limits contained in the permit.

The Permitte shall record the monthly operating hours of the cooling tower, and calculate PM_{10} emissions on a rolling 12-month basis using operating hours, measured TDS concentrations, the maximum design capacity flow rate, and the emission factor and equation described in the permit application and Technical Support Document.

PM testing will be required on one of the existing GT1 and GT2 units to develop an emission factor that can be used to accurately calculate PM_{10} emissions from these units, as part of the PM_{10} emission cap compliance demonstration.

9.3 Total Facility Emissions after the Modernization Project.

The total potential emissions for the Ocotillo Power Plant based on the proposed emission limitations in this application are summarized in Table 7-5. The facility wide VOC emissions include emissions from a 2,000 gallon gasoline storage tank, with an assumed fuel useage of 120,000 gallons per year, resulting in 742 lb/yr VOC emissions based on EPA's Tanks program.

TABLE 7-5. Total potential emissions for the Ocotillo Power Plant after the Ocotillo Modernization Project.

POLLUTANT		Allowable Emissions, tons per year								
		Gas Turbines 1 - 2	New Gas Turbines 3 - 7	New Emergency Generators	Existing Emergency Generator	New Cooling Tower	New and Existing Tanks	SF_6 Insulated Equipment	Natural Gas Piping Systems	TOTAL
Carbon Monoxide	CO	122.9	239.2	10.8	8.9					381.8
Nitrogen Oxides	NO_x	479.7	125.3		0.3					605.3
Particulate Matter	PM	12.4	54.9	0.6	0.0	5.4				73.3
Particulate Matter	PM_{10}	12.4	54.9	0.6	0.0	1.7				63.0
Particulate Matter	$PM_{2.5}$	12.4	54.9	0.6	0.0	1.0				68.9
Sulfur Dioxide	SO_2	0.9	5.9	0.02	0.00					6.8
Vol. Organic Cmpds	VOC	3.1	43.1	0.83	0.01		0.38			47.5
Sulfuric Acid Mist	H_2SO_4	0.1	0.6	0.0	0.0					0.68
Fluorides (as HF)	HF	0.00000	0.00000	0.00326	0.00000					0.0033
Lead	Pb	0.0007	0.0049	0.0	0.0					0.006
Carbon Dioxide	CO_2	175,371	1,099,504	1,968.9	51.7					1,276,895
Greenhouse Gases	CO_2e	175,552	1,100,640	1,975.6	51.9			132	102	1,278,453

Appendix A.

Maricopa County Air Quality Department's STANDARD PERMIT APPLICATION FORM, and the EMISSION SOURCES FORM(s).

MARICOPA COUNTY
ENVIRONMENTAL SERVICES DEPARTMENT
DIVISION OF AIR POLLUTION CONTROL

1001 N. Central Ave., Ste 201
Phoenix, AZ 85004
(602) 506-6010

STANDARD PERMIT APPLICATION FORM

(As required by A.R.S. § 49-480, and Chapter 3, Article 3, Arizona Administrative Code)

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

2. Mailing Address: **400 North 5th Street**
City: **Phoenix** State: **AZ** ZIP: **85004**

3. Plant Name (if different from item #1 above): **Ocotillo Power Plant**

4. Name (or names) of Owner or Operator: **Arizona Public Service Company**
Phone: **(602) 250-1375**

5. Name of Owner's Agent: **Not Applicable**
Phone: ____________

5. Plant/Site Manager or Contact Person: **Anne Carlton**
Phone: **(602) 250-1375**

7. Proposed Equipment/Plant Location Address: **1500 East University Drive**
City: **Tempe** County: **Maricopa** ZIP: **85281**
Indian Reservation (if applicable): **Not Applicable**
Section/Township/Range: ____________
Latitude: **33°25'32"N** Longitude: **111°54'48"W** Elevation: **1,178** ft.

8. General Nature of Business: **Electric Power Generation**
Standard Industrial Classification Code: **4911**
Type of Organization: **X** Corporation ___ Individual Owner
___ Partnership ___ Government Entity (Government Facility Code: ____________)
___ Other: ____________

10. Permit Application Basis: ___ New Source **X** Revision ___ Renewal of Existing Permit
___ Portable Source ___ General Permit (Check all that apply.)
For renewal or modification, include existing permit number: **Operation Permit No. V95-007**
Date of Commencement of Construction or Modification: **January 1, 2016**
Is any of the equipment to be leased to another individual or entity? ___ Yes **X** No

11. Signature of Responsible Official of Organization Dennis J Irvin
Official Title of Signer: **Plant Manager**

12. Typed or Printed Name of Signer: **Dennis Irvin**
Date: 9/29/2015 Phone Number: 520-233-4092

COMPANY NAME & LOCATION **Arizona Public Service - Ocotillo Power Plant**

EMISSION SOURCES

DATE **1/25/15**

Estimated Potential to Emit as per Rule 100.
Review of applications and issuance of permits will ba expedited by supplying all necessary information on this Table.

REGULATED AIR POLLUTANT DATA					EMISSION POINT DISCHARGE PARAMETERS									
EMISSION POINT (1)		CHEMICAL COMPOSITION OF TOTAL STREAM	AIR POLLUTANT EMISSION RATE		UTM COORDINATES OF EMISSION PT. (5)			STACK SOURCES (6)					NONPOINT SOURCES (7)	
										EXIT DATA				
NUMBER	NAME	REGULATED AIR POLLUTANT NAME (2)	#/ HR. (3)	TONS/ YEAR (4)	ZONE	EAST (Mtrs)	NORTH (Mtrs)	HEIGHT ABOVE GROUND /feet	HEIGHT ABOVE STRUC. /feet	DIA. (ft)	VEL. (fps)	TEMP. (oF)	LENGTH (ft.)	WIDTH (ft.)
GT3, GT4, GT5, GT6, GT7	**General Electric Model LMS100 Simple Cycle Gas Turbine (5 total)**	**Carbon Monoxide**	**13.53**	**47.8**		**Refer to Appendix F of application.**		**85**		**13.5**	**60**	**844**		
		Nitrogen Oxides	**9.26**	**26.9**										
		Particulate Matter	**5.40**	**11.0**										
		PM10	**5.40**	**11.0**										
		PM2.5	**5.40**	**11.0**										
		Sulfur Dioxide	**0.58**	**1.2**										
		Vol. Org. Compounds	**2.64**	**8.6**										
		Sulfuric Acid Mist	**0.06**	**0.1**										
		Fluorides (as HF)	**0.00**	**0.0**										
		Lead	**0.00**	**0.0**										
		Carbon Dioxide	**113,467**	**219,900.8**										
		Greenhouse Gases	**113,584**	**220,127.9**										

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA L **1,178** feet
ADEQ STANDARD CONDITIONS ARE 293K AND 101.3 KILOPASCALS (A.A. C. RIB -2-101)
General Instructions:

****Please refer to the air permit application, Chapter 3, for detailed emissions data.**

COMPANY NAME & LOCATION **Arizona Public Service - Ocotillo Power Plant**

EMISSION SOURCES

PAGE **2** OF **3**
DATE **9/25/15**

Estimated Potential to Emit as per Rule 100.
Review of applications and issuance of permits will ba expedited by supplying all necessary information on this Table.

REGULATED AIR POLLUTANT DATA					EMISSION POINT DISCHARGE PARAMETERS									
EMISSION POINT (1)		CHEMICAL COMPOSITION OF TOTAL STREAM	AIR POLLUTANT EMISSION RATE		UTM COORDINATES OF EMISSION PT. (5)			STACK SOURCES (6)					NONPOINT SOURCES (7)	
										EXIT DATA				
NUMBER	NAME	REGULATED AIR POLLUTANT NAME (2)	#/ HR. (3)	TONS/ YEAR (4)	ZONE	EAST (Mtrs)	NORTH (Mtrs)	HEIGHT ABOVE GROUND /feet	HEIGHT ABOVE STRUC. /feet	DIA. (ft)	VEL. (fps)	TEMP. (oF)	LENGTH (ft.)	WIDTH (ft.)
GTCT 3 - 7 Cooling Tower	**Six (6) Cell Cooling Tower**	**Particulate Matter**	**1.23**	**5.39**		**Refer to Appendix F of application.**		**40**		**30 (each cell)**	**33**	**87**		
		PM10	**0.39**	**1.70**										
		PM2.5	**0.23**	**1.02**										

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LE **1,178** feet
ADEQ STANDARD CONDITIONS ARE 293K AND 101.3 KILOPASCALS (A.A. C. RIB -2-101)
General Instructions:

****Please refer to the air permit application, Chapter 3, for detailed emissions data.**

COMPANY NAME & LOCAT **Arizona Public Service - Ocotillo Power Plant**

EMISSION SOURCES

PAGE **3** OF **3**
DATE **1/25/15**

Estimated Potential to Emit as per Rule 100.
Review of applications and issuance of permits will ba expedited by supplying all necessary information on this Table.

REGULATED AIR POLLUTANT DATA					EMISSION POINT DISCHARGE PARAMETERS									
EMISSION POINT (1)		CHEMICAL COMPOSITION OF	AIR POLLUTANT EMISSION RATE		UTM COORDINATES OF EMISSION PT. (5)			STACK SOURCES (6)					NONPOINT SOURCES (7)	
										EXIT DATA				
NUMBER	NAME	REGULATED AIR POLLUTANT NAME (2)	#/ HR. (3)	TONS/ YEAR (4)	ZONE	EAST (Mtrs)	NORTH (Mtrs)	HEIGHT ABOVE GROUND /feet	HEIGHT ABOVE STRUC. /feet	DIA. (ft)	VEL. (fps)	TEMP. (oF)	LENGTH (ft.)	WIDTH (ft.)
EG1 and EG2	**2.5 megawatt (MWe) emergency generators (2 total)**	**CO**	**21.56**	**5.4**		**Refer to Appendix F of application.**		**16**		**1.5**	**185**	**794**		
		NOx	**39.42**	**9.9**										
		PM	**1.24**	**0.3**										
		PM10	**1.24**	**0.3**										
		PM2.5	**1.24**	**0.3**										
		SO2	**0.04**	**0.0**										
		VOC	**1.65**	**0.4**										
		H2SO4	**0.00**	**0.0**										
		F	**0.01**	**0.0**										
		Pb	**0.00**	**0.0**										
		CO2	**3,937.71**	**984.4**										
		CO2e	**3,951.22**	**987.8**										

GROUND ELEVATION OF FACILITY **1,178** feet
ADEQ STANDARD CONDITIONS ARE 293K AND 101.3 KILOPASCALS (A.A. C. RIB -2-101)
General Instructions:

****Please refer to the air permit application, Chapter 3, for detailed emissions data.**

Compliance Certification

	Permit Terms & Conditions	Methods Used for Compliance	Compliance Status	Deviations
GENERAL CONDITIONS				
Section 1	AIR POLLUTION PROHIBITED: The Permittee shall not discharge from any source whatever into the atmosphere regulated air pollutants which exceed in quantity or concentration that specified and allowed in the County or SIP Rules, the Arizona Administrative Code (AAC) or the Arizona Revised Statutes (ARS), or which cause damage to property or unreasonably interfere with the comfortable enjoyment of life or property of a substantial part of a community, or obscure visibility, or which in any way degrade the quality of the ambient air below the standards established by the Maricopa County Board of Supervisors or the Director of the Arizona Department of Environmental Quality (ADEQ). The Permittee shall not discharge from any source whatever into the atmosphere regulated air pollutants so as to create or maintain a nuisance.	Standard operating procedures; compliance reviews.	Continuous	No
Section 2	CIRCUMVENTION: The Permittee shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of regulated air pollutants to the atmosphere, conceals or dilutes an emission which would otherwise constitute a violation of this Permit or any Rule or any emission limitation or standard. The Permittee shall not circumvent the requirements concerning dilution of regulated air pollutants by using more emission openings than is considered normal practice by the industry or activity in question.	Standard operating procedures; compliance reviews.	Continuous	No

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 3	CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS: Any application form, report, or compliance certification submitted under County or Federal Rules or these Permit Conditions shall contain certification by a responsible official of truth, accuracy, and completeness of the application form or report as of the time of submittal. This certification and any other certification required under County or Federal Rules or these Permit Conditions shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. The Permit Conditions contained herein are substantially based on information contained in the certified application submitted by the Permittee and all subsequent submittals. The information contained in such submittals was relied upon as being truthful, accurate, and complete for development of this Permit.	Standard operating procedures; compliance reviews.	Continuous	No
Section 4.A.1	COMPLIANCE WITH ALL CONDITIONS OF THE PERMIT, STATUTES, AND RULES: The Permittee must comply with all conditions of this permit and with all applicable requirements of Arizona air quality statutes and the air quality rules. Compliance with permit terms and conditions does not relieve, modify, or otherwise affect the Permittee's duty to comply with all applicable requirements of Arizona air quality statutes and the Maricopa County Air Pollution Control Regulations. Any permit noncompliance is grounds for enforcement action; for a permit termination, revocation and reissuance, or revision; or for denial of a permit renewal application. Noncompliance with any federally enforceable requirement in this Permit constitutes a violation of the Act.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 4.A.2	COMPLIANCE REQUIRED: The Permittee shall halt or reduce the permitted activity in order to maintain compliance with applicable requirements of Federal laws, Arizona laws, the County Rules, or other conditions of this Permit.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 4.A.3	COMPLIANCE – RACT: For any major source operating in a nonattainment area for any pollutant(s) for which the source is classified as a major source, the source shall comply with reasonably available control technology (RACT) as defined in County Rule 100.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 4.A.4	COMPLIANCE – BACT: For any major source operating in a nonattainment area designated as serious for PM10, for which the source is classified as a major source for PM10, the source shall comply with the best available control technology (BACT), as defined in County Rule 100 for PM10.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 4.B	COMPLIANCE CERTIFICATION REQUIREMENTS: The Permittee shall file an annual or semiannual Compliance Certification, as specified in the Specific Conditions section of this Permit, with the Control Officer and also with the Administrator of the USEPA. The report shall certify compliance with the terms and conditions contained in this Permit, including emission limitations, standards, or work practices and shall be submitted at such times as required by the Specific Conditions of this Permit. The Compliance Certification shall be on a form supplied or approved by the Control Officer and shall include the following: 1) The identification of each term or condition of the permit that is the basis of the certification; 2) The compliance status; 3) Whether compliance was continuous or intermittent; 4) The method(s) used for determining the compliance status of the source, currently and over the reporting period; and 5) Other facts as the Control Officer may require to determine the compliance status of the source.	Standard operating procedures; compliance reviews.	Continuous	No

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 4.C	COMPLIANCE PLAN: Based on the certified information contained in the application for this Permit, the facility is in compliance with all applicable requirements in effect as of the first date of public notice of the proposed conditions for this Permit unless a Compliance Plan is included in the Specific Conditions of this Permit. The Permittee shall continue to comply with all applicable requirements and shall meet any applicable requirements that may become effective during the term of this permit on a timely basis.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 5	CONFIDENTIALITY CLAIMS: Any records, reports or information obtained from the Permittee under the County Rules or this Permit shall be available to the public, unless the Permittee files a claim of confidentiality in accordance with ARS §49-487(c) that: A. Precisely identifies the information in the permit(s), records, or reports that is considered confidential, and B. Provides sufficient supporting information to allow the Control Officer to evaluate whether such information satisfies the requirements related to trade secrets or, if applicable, how the information, if disclosed, could cause substantial harm to the person's competitive position. The claim of confidentiality is subject to the determination by the Control Officer as to whether the claim satisfies these requirements. A claim of confidentiality shall not excuse the Permittee from providing any and all information required or requested by the Control Officer and shall not be a defense for failure to provide such information. If the Permittee submits information with an application under a claim of confidentiality pursuant to ARS §49-487 and County Rule 200, the Permittee shall submit a copy of such information directly to the Administrator of the USEPA.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 6.A.1	CONTINGENT REQUIREMENTS – ACID RAIN: Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated pursuant to Title IV of the CAA and incorporated pursuant to County Rule 371, both provisions shall be incorporated into this Permit and shall be enforceable by the Administrator.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 6.A.2	CONTINGENT REQUIREMENTS – ACID RAIN: The Permittee shall not allow emissions exceeding any allowances that the source lawfully holds pursuant to Title IV of the CAA or the regulations promulgated thereunder and incorporated pursuant to County Rule 371. a) No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program and incorporated pursuant to County Rule 371, provided that such increases do not require a permit revision pursuant to any other applicable requirement. b) No limit is placed on the number of allowances held by the Permittee. The Permittee may not, however, use allowances as a defense to noncompliance with any other applicable requirement. c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated pursuant to Title IV of the CAA. d) All of the following prohibitions apply to any unit subject to the provisions of Title IV of the CAA and incorporated into this Permit pursuant to County Rule 371; (1) Annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide held by the owners or operators of the unit or the designated representative of the owners or operators. (2) Exceedances of applicable emission rates. (3) The use of any allowance prior to the year for which it was allocated. (4) Violation of any other provision of the permit.	Standard operating procedures; compliance reviews; company administrative procedures.	Continuous	No
Section 6.B	CONTINGENT REQUIREMENTS – ASBESTOS: The Permittee shall comply with the applicable requirements of Sections §§61.145 through 61.147 and §61.150 of the National Emission Standard for Asbestos and County Rule 370 for all demolition and renovation projects.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 6.C	CONTINGENT REQUIREMENTS – RISK MANAGEMENT PLAN (RMP): Should this stationary source, as defined in 40 CFR §68.3, be subject to the accidental release prevention regulations in Part 68, then the Permittee shall submit an RMP by the date specified in Section 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 CFR Part 70. However, neither the RMP nor modifications to the RMP shall be considered to be a part of this Permit.	Standard operating procedures; compliance reviews.	Continuous Term NA during this period.	No

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 6.D	CONTINGENT REQUIREMENTS – STRATOSPHERIC OZONE PROTECTION: If applicable, the Permittee shall follow the requirements of 40 CFR §§82.106 through 82.124 with respect to the labeling of products using ozone depleting substances. If applicable, the Permittee shall comply with all of the following requirements with respect to recycling and emissions reductions: 1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR §82.156. 2) Equipment used during maintenance, service, repair, or disposal of appliances must meet the standards for recycling and recovery equipment in accordance with 40 CFR §82.158. 3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by a certified technician pursuant to 40 CFR §82.161. If applicable, the Permittee shall follow the requirements of 40 CFR Subpart G, including all Appendices, with respect to the safe alternatives policy on the acceptability of substitutes for ozone-depleting compounds.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 6.E.	CONTINGENT REQUIREMENTS – MANDATORY GREENHOUSE GAS REPORTING: The Permittee shall comply with 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, and all subparts as applicable.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 7	DUTY TO SUPPLEMENT OR CORRECT APPLICATION: If the Permittee fails to submit any relevant facts or has submitted incorrect information in a permit application, the Permittee shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, the Permittee shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a proposed permit.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 8	EMERGENCY EPISODES: If an air pollution alert, warning, or emergency has been declared, the Permittee shall comply with any applicable requirements of County Rule 600 §302.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No
Section 9	EMERGENCY PROVISIONS: An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, that requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the requirements of this Permit Condition are met. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that: A. An emergency occurred and that the Permittee can identify the cause or causes of the emergency; B. At the time of the emergency, the permitted source was being properly operated; C. During the period of the emergency the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in this permit; and D. Fulfill the emergency reporting requirements contained in Permit Condition 16.D. In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof. This provision is in addition to any emergency or upset provision contained in any applicable requirement.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 10.A	EXCESS EMISSIONS – EXEMPTIONS: The excess emissions provisions of this Permit Condition do not apply to the following standards and limitations: 1) Promulgated pursuant to Section 111 (Standards of Performance for New Stationary Sources) of the Clean Air Act (Act) or Section 112 (National Emission Standards For Hazardous Air Pollutants) of the Act; 2) Promulgated pursuant to Title IV (Acid Deposition Control) of the Act or the regulations promulgated thereunder and incorporated under Rule 371 (Acid Rain) of these rules or Title VI (Stratospheric Ozone Protection) of the Act; 3) Contained in any Prevention of Significant Deterioration (PSD) or New Source Review (NSR) permit issued by Maricopa County Air Quality Department or the Environmental Protection Agency (EPA); 4) Included in a permit to meet the requirements of County Rule 240 (Permit Requirements for New Major Sources and Major Modifications to Existing Major Sources), Subsection 308.1(e) (Permit Requirements For Sources Located In Attainment And Unclassified Areas) of these rules.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 10.B	EXCESS EMISSIONS – AFFIRMATIVE DEFENSE FOR MALFUNCTIONS: Emissions in excess of an applicable emission limitation due to malfunction shall constitute a violation. The permitted source with emissions in excess of an applicable emission limitation due to malfunction has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the Permittee has complied with the excess emissions reporting requirements of these Permit Conditions and has demonstrated all of the following: 1) The excess emissions resulted from a sudden and unavoidable breakdown of the process equipment or the air pollution control equipment beyond the reasonable control of the operator; 2) The source's air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions; 3) If repairs were required, the repairs were made in an expeditious fashion when the applicable emission limitations were being exceeded. Off-shift labor and overtime were utilized where practicable to ensure that the repairs were made as expeditiously as possible. If off-shift labor and overtime were not utilized, then the Permittee satisfactorily demonstrated that such measures were impractical; 4) The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions; 5) All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality; 6) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; 7) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in County Rule 510 that could be attributed to the emitting source; 8) The excess emissions did not stem from any activity or event that could have been foreseen and avoided, or planned, and could not have been avoided by better operations and maintenance practices; 9) All emissions monitoring systems were kept in operation, if at all practicable; and 10) The Permittee's actions in response to the excess emissions were documented by contemporaneous records.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA

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<table>
<tr><th colspan="2">Permit Terms & Conditions</th><th>Methods Used for Compliance</th><th>Compliance Status</th><th>Deviations</th></tr>
<tr><td>Section 10.C</td><td>EXCESS EMISSIONS – AFFIRMATIVE DEFENSE FOR STARTUP AND SHUTDOWN:

1) Except as provided in paragraph 2) below, and unless otherwise provided for in the applicable requirement, emissions in excess of an applicable emission limitation due to startup and shutdown shall constitute a violation. The permitted source with emissions in excess of an applicable emission limitation due to startup and shutdown has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the Permittee has complied with the excess emissions reporting requirements of these Permit Conditions and has demonstrated all of the following:

a) The excess emissions could not have been prevented through careful and prudent planning and design;
b) If the excess emissions were the result of a bypass of control equipment, the bypass was unavoidable to prevent loss of life, personal injury, or severe damage to air pollution control equipment, production equipment, or other property;
c) The source's air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;
d) The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable, during periods of such emissions;
e) All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;
f) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in County Rule 510 (Air Quality Standards) that could be attributed to the emitting source;
g) All emissions monitoring systems were kept in operation, if at all practicable; and
h) The Permittee's actions in response to the excess emissions were documented by contemporaneous records.

2) If excess emissions occur due to a malfunction during routine startup and shutdown, then those instances shall be treated as other malfunctions subject to paragraph B of this Permit Condition.</td><td>NA Explanatory statement of law and therefore not amendable to compliance certification.</td><td>NA</td><td>NA</td></tr>
</table>

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 10.D	EXCESS EMISSIONS – AFFIRMATIVE DEFENSE FOR MALFUNCTIONS DURING SCHEDULED MAINTENANCE: If excess emissions occur due to malfunction during scheduled maintenance, then those instances will be treated as other malfunctions subject to paragraph B of this Permit Condition.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 10.E	EXCESS EMISSIONS – DEMONSTRATION OF REASONABLE AND PRACTICABLE MEASURES: For an affirmative defense under paragraphs B and C of this Permit Condition, the Permittee shall demonstrate, through submission of the data and information required by this Permit Condition and the excess emissions reporting requirements of these Permit Conditions, that all reasonable and practicable measures within the Permittee's control were implemented to prevent the occurrence of the excess emissions.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 11	FEES: The Permittee shall pay fees to the Control Officer pursuant to ARS §49-480(D) and County Rule 280.	Standard operating procedures; compliance reviews.	Continuous	No
Section 12	MODELING: Where the Control Officer requires the Permittee to perform air quality impact modeling, the Permittee shall perform the modeling in a manner consistent with the 40 CFR 51, Appendix W, "Guideline on Air Quality Models", as of July 1, 2004 (and no future amendments or additions), and is adopted by reference. Where the person can demonstrate that an air quality impact model specified in the guideline is inappropriate, the model may be modified or another model substituted if found to be acceptable to the Control Officer.	Standard operating procedures; compliance reviews.	Continuous Term NA during this period.	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 13.A	MONITORING REQUIREMENTS: The Permittee shall monitor, sample, or perform other studies to quantify emissions of regulated air pollutants or levels of air pollution that may reasonably be attributable to the facility if required to do so by the Control Officer, either by Permit or by order in accordance with County Rule 200 §310.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 13.B	TESTING REQUIREMENTS: Except as otherwise specified in these Permit Conditions or by the Control Officer, the Permittee shall conduct required testing used to determine compliance with standards or permit conditions established pursuant to the County or SIP Rules or these Permit Conditions in accordance with County Rule 270 and the applicable testing procedures contained in the Arizona Testing Manual for Air Pollutant Emissions or other approved USEPA test methods.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 13.C	TESTING FACILITIES: The Permittee shall provide, or cause to be provided, performance testing facilities as follows: 1) Sampling ports adequate for test methods applicable to such source. 2) Safe sampling platform(s). 3) Safe access to sampling platforms(s). 4) Utilities for sampling and testing equipment.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 14.A	PERMITS – BASIC: This Permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a permit revision, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any Permit Condition.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 14.B	PERMITS – PERMITS AND PERMIT CHANGES, AMENDMENTS AND REVISIONS: 1) The Permittee shall comply with the Administrative Requirements of Section 400 of County Rule 210 for all changes, amendments and revisions at the facility for any source subject to regulation under County Rule 200, shall comply with all required time frames, and shall obtain any required preapproval from the Control Officer before making changes. All applications shall be filed in the manner and form prescribed by the Control Officer. The application shall contain all the information necessary to enable the Control Officer to make the determination to grant or to deny a permit or permit revision including information listed in County Rule 200 §309 and County Rule 210 §301. 2) The Permittee shall supply a complete copy of each application for a permit, a minor permit revision, or a significant permit revision directly to the Administrator of the USEPA. The Control Officer may require the application information to be submitted in a computer-readable format compatible with the Administrator's national database management system. 3) While processing an application, the Control Officer may require the applicant to provide additional information and may set a reasonable deadline for a response. 4) No permit revision shall be required pursuant to any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 14.C	PERMITS – POSTING: 1) The Permittee shall keep a complete permit clearly visible and accessible on the site where the equipment is installed. 2) Any approved Dust Control Plan or Dust Control Permit required by County Rule 310 shall be posted in a conspicuous location at the work site, within on-site equipment, or in an on-site vehicle, or shall otherwise be kept available on site at all times.	Standard operating procedures; compliance reviews.	Continuous	No
Section 14.D	PERMITS – PROHIBITION ON PERMIT MODIFICTION: The Permittee shall not willfully deface, alter, forge, counterfeit, or falsify this permit.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 14.E	PERMITS – RENEWAL: 1) The Permittee shall submit an application for the renewal of this Permit in a timely and complete manner. The Permittee shall file all permit applications in the manner and form prescribed by the Control Officer. For purposes of permit renewal, a timely application is one that is submitted at least six months, but not more than 18 months, prior to the date of permit expiration. A complete application shall contain all of the information required by the County Rules including Rule 200 §309 and Rule 210 §§301 & 302.3. 2) The Control Officer may require the Permittee to provide additional information and may set a reasonable deadline for a response. 3) If the Permittee submits a timely and complete application for a permit renewal, but the Control Officer has failed to issue or deny the renewal permit before the end of the term of the previous permit, then the permit shall not expire until the renewal permit has been issued or denied. This protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit, by the deadline specified in writing by the Control Officer, any additional information identified as being needed to process the application.	Standard operating procedures; compliance reviews.	Continuous	No

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<table>
<tr><th colspan="2">Permit Terms & Conditions</th><th>Methods Used for Compliance</th><th>Compliance Status</th><th>Deviations</th></tr>
<tr><td>Section 14.F</td><td>PERMITS – REVISION/REOPENING/REVOCATION:

1) If the Permittee becomes subject to a standard promulgated by the Administrator under Section 112(d) of the CAA, the Permittee shall, within 12 months of the date on which the standard was promulgated, submit an application for a permit revision demonstrating how the source will comply with the standard.
2) This permit shall be reopened and revised to incorporate additional applicable requirements adopted by the Administrator pursuant to the CAA that become applicable to the facility if this permit has a remaining permit term of three or more years and the facility is a major source. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which this Permit is due to expire unless the original permit or any of its terms have been extended pursuant to Rule 200 §403.2.
Any permit revision required pursuant to this Permit Condition, 14.G.1, shall reopen the entire permit, shall comply with provisions in County Rule 200 for permit renewal, and shall reset the five year permit term.
3) This permit shall be reopened and revised under any of the following circumstances:
a) Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the Title V permit.
b) The Control Officer or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.
c) The Control Officer or the Administrator determines that the permit must be revised or revoked to assure compliance with the applicable requirements.
Proceedings to reopen and issue a permit under this Permit Condition, 14.G.2, shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the Permit for which cause to reopen exists.
4) This permit shall be reopened by the Control Officer and any permit shield revised when it is determined that standards or conditions in the permit are based on incorrect information provided by the applicant.
5) This Permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Permit revision, revocation and reissuance, or termination or of a notification of planned changes or anticipated noncompliance does not stay any Permit Condition.</td><td>NA Explanatory statement of law and therefore not amendable to compliance certification.</td><td>NA</td><td>NA</td></tr>
</table>

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 14.G.1	REQUIREMENTS FOR A PERMIT: No source may operate after the time that it is required to submit a timely and complete application except as noted in Sections 403 and 405 of County Rule 210. Permit expiration terminates the Permittee's right to operate. However, if a source submits a timely and complete application, as defined in County Rule 210 §301.4, for permit issuance or renewal, the source's failure to have a permit is not a violation of the County Rules until the Control Officer takes final action on the application. The Source's ability to operate without a permit as set forth in this paragraph shall be in effect from the date the application is determined to be complete until the final permit is issued. This protection shall cease to apply if, subsequent to the completeness determination, the applicant fails to submit, by the deadline specified in writing by the Control Officer, any additional information identified as being needed to process the application.	Standard operating procedures; compliance reviews.	Continuous	No
Section 14.G.2	REQUIREMENTS FOR A PERMIT – DUST GENERATION ACTIVITIES If the Permittee engages in or allows any routine dust generating activities at the facility, the Permittee shall apply to have the routine dust generating activity covered as part of this Permit. Nonroutine activities, such as construction and revegetation, require a separate Dust Control Permit that must be obtained from the Control Officer before the activity may begin. a) The Permittee shall not commence any routine dust-generating operation that disturbs a surface area of 0.10 acre or greater without first submitting a Dust Control Plan to the Control Officer. b) The Permittee shall request a Dust Control Plan revision with a submittal in the manner and form prescribed by the Control Officer if: (1) The acreage of a project changes; (2) The permit holder changes; (3) The name(s), address(es), or phone numbers of person(s) responsible for the submittal and implementation of the Dust Control Plan and responsible for the dust-generating operation change; and (4) If the activities related to the purposes for which the Dust Control permit was obtained change. c) A subcontractor who is engaged in dust-generating operations at a site that is subject to a Dust Control Permit shall register with the Control Officer and follow those registration requirements in County Rule 200.	Standard operating procedures; compliance reviews.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 14.G.3	REQUIREMENTS FOR A PERMIT – BURN PERMIT: The Permittee shall obtain a Permit To Burn from the Control Officer before conducting any open outdoor fire except for the activities listed in County Rule 314 §§302.1, 302.2, and 303.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No
Section 14.H	PERMITS – RIGHTS AND PRIVILEGES: This Permit does not convey any property rights nor exclusive privilege of any sort.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 14.I	PERMITS – SEVERABILITY: The provisions of this Permit are severable, and, if any provision of this Permit is held invalid, the remainder of this Permit shall not be affected thereby.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 14.J	PERMITS – SCOPE: The issuance of any permit or permit revision shall not relieve the Permittee from compliance with any Federal laws, Arizona laws, or the County or SIP Rules, nor does any other law, regulation or permit relieve the Permittee from obtaining a permit or permit revision required under the County Rules. Nothing in this permit shall alter or affect the following: 1) The provisions of Section 303 of the Act, including the authority of the Administrator pursuant to that section. 2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of permit issuance. 3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Act. 4) The ability of the Administrator of the USEPA or of the Control Officer to obtain information from the Permittee pursuant to Section 114 of the Act, or any provision of State law. 5) The authority of the Control Officer to require compliance with new applicable requirements adopted after the permit is issued.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 14.K	TERMS OF PERMIT: This Permit shall remain in effect for no more than 5 years from the date of issuance.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 14.L	PERMITS – TRANSFER: Except as provided in ARS §49-429 and County Rule 200, this permit may be transferred to another person if the Permittee gives notice to the Control Officer in writing at least 30 days before the proposed transfer and complies with the permit transfer requirements of County Rule 200 and the administrative permit amendment procedures pursuant to County Rule 210.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 15.A	RECORDKEEPING – RECORDS REQUIRED: The Permittee shall maintain records of all emissions testing and monitoring, records detailing all malfunctions which may cause any applicable emission limitation to be exceeded, records detailing the implementation of approved control plans and compliance schedules, records required as a condition of any permit, records of materials used or produced and any other records relating to the emission of air contaminants which may be requested by the Control Officer.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 15.B	RECORDKEEPING – RETENTION OF RECORDS: Unless a longer time frame is specified by the Rules or these Permit Conditions, the Permittee shall retain information and records required by either the Control Officer or these Permit Conditions as well as copies of summarizing reports recorded by the Permittee and submitted to the Control Officer for 5 years after the date on which the pertinent report is submitted.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 15.C	RECORDKEEPING – MONITORING RECORDS: The Permittee shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings or physical records for continuous monitoring instrumentation, and copies of all reports required by the permit. Records of any monitoring required by this Permit shall include the following: 1) The date, place as defined in the permit, and time of sampling or measurements; 2) The date(s) analyses were performed; 3) The company or entity that performed the analyses; 4) The analytical techniques or methods used; 5) The results of such analyses; and 6) The operating conditions as existing at the time of sampling or measurement.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 15.D	RECORDKEEPING – RIGHT OF INSPECTION OF RECORDS: When the Control Officer has reasonable cause to believe that the Permittee has violated or is in violation of any provision of County Rule 100 or any County Rule adopted under County Rule 100, or any requirement of this permit, the Control Officer may request, in writing, that the Permittee produce all existing books, records, and other documents evidencing tests, inspections, or studies which may reasonably relate to compliance or noncompliance with County Rules adopted under County Rule 100. No person shall fail nor refuse to produce all existing documents required in such written request by the Control Officer.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 16.A	REPORTING – ANNUAL EMISSION INVENTORY REPORT: Upon request of the Control Officer and as directed by the Control Officer, the Permittee shall complete and shall submit to the Control Officer an annual emissions inventory report. The report is due by April 30th or 90 days after the Control Officer makes the inventory forms available, whichever occurs later. The annual emissions inventory report shall be in the format provided by the Control Officer. The Control Officer may require submittal of supplemental emissions inventory information forms for air contaminants under ARS §49-476.01, ARS §49-480.03 and County Rule 372.	Standard operating procedures; compliance reviews.	Continuous	No
Section 16.B	REPORTING – DATA REPORTING: When requested by the Control Officer, the Permittee shall furnish information to locate and classify air contaminant sources according to type, level, duration, frequency and other characteristics of emissions and such other information as may be necessary. This information shall be sufficient to evaluate the effect on air quality and compliance with the County or SIP Rules. The Permittee may be required to submit annually, or at such intervals specified by the Control Officer, reports detailing any changes in the nature of the source since the previous report and the total annual quantities of materials used or air contaminants emitted.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 16.C	REPORTING – DEVIATION REPORTING: The Permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions. Unless specified otherwise elsewhere in these Permit Conditions, an upset for the purposes of this Permit Condition shall be defined as the operation of any process, equipment or air pollution control device outside of either its normal design criteria or operating conditions specified in this Permit and which results in an exceedance of any applicable emission limitation or standard. The Permittee shall submit the report to the Control Officer by certified mail, facsimile, or hand delivery within 2 working days of knowledge of the deviation; and the report shall contain a description of the probable cause of such deviations and any corrective actions or preventive measures taken. In addition, the Permittee shall report within a reasonable time of any long-term corrective actions or preventive actions taken as the result of any deviations from permit requirements. All instances of deviations from the requirements of this Permit shall also be clearly identified in the semiannual monitoring reports.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No
Section 16.D	REPORTING – EMERGENCY REPORTING: The Permittee shall, as soon as possible, telephone the Control Officer giving notice of the emergency and submit notice of the emergency to the Control Officer by certified mail, facsimile, or hand delivery within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice shall contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No
Section 16.E	REPORTING – EMISSION STATEMENTS REQUIRED AS STATED IN THE ACT: Upon request of the Control Officer and as directed by the Control Officer, the Permittee shall provide the Control Officer with an annual emission statement, in such form as the Control Officer prescribes, showing measured actual emissions or estimated actual emissions. At a minimum the emission statement shall contain all information required by the Consolidated Emissions Reporting Rule in 40 CFR 51, Subpart A, Appendix A, Table 2A. The statement shall contain emissions for the time period specified by the Control Officer. The statement shall also contain a certification by a responsible official of the company that the information contained in the statement is accurate to the best knowledge of the individual certifying the statement.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No

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<tr><td>Section 16.F</td><td>REPORTING – EXCESS EMISSIONS REPORTING:

1) The Permittee shall report to the Control Officer any emissions in excess of the limits established either by the County or SIP Rules or these Permit Conditions. The report shall be in two parts as specified below:

a) Notification by telephone or facsimile within 24 hours of the time when the Permittee first learned of the occurrence of excess emissions. This notification shall include all available information listed in Permit Condition 16.F.2.
b) A detailed written notification of an excess emissions report shall be submitted within 72 hours of the telephone notification in Permit Condition 16.F.1.a.

2) The excess emissions report shall contain the following information:

a) The identity of each stack or other emission point where the excess emissions occurred.
b) The magnitude of the excess emissions expressed in the units of the applicable emission limitation and the operating data and calculations used in determining the magnitude of the excess emissions.
c) The time and duration or expected duration of the excess emissions.
d) The identity of the equipment from which the excess emissions emanated.
e) The nature and cause of such emissions.
f) The steps taken if the excess emissions were the result of a malfunction to remedy the malfunction and the steps taken or planned to prevent the recurrence of such malfunction.
g) The steps that were or are being taken to limit the excess emissions.
h) If this Permit contains procedures governing source operation during periods of startup or malfunction and the excess emissions resulted from startup or malfunction, the report shall contain a list of the steps taken to comply with the Permit procedures.

3) In the case of continuous or recurring excess emissions, the notification requirements of this section shall be satisfied if the Permittee provides the required notification after excess emissions are first detected and includes in the notification an estimate of the time the excess emissions will continue. Excess emissions occurring after the estimated time period or changes in the nature of the emissions as originally reported shall require additional notification that meets the criteria of this Permit Condition.</td><td>Standard operating procedures; compliance reviews; recordkeeping.</td><td>Continuous Term NA during this period.</td><td>No</td></tr>
</table>

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 16.G	REPORTING – OTHER REPORTING: The Permittee shall furnish to the Control Officer, within a reasonable time, any information that the Control Officer may request in writing to determine whether cause exists for revising, revoking and reissuing this permit, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to the Control Officer copies of records required to be kept by this Permit. For information claimed to be confidential, the Permittee shall furnish a copy of such records directly to the Administrator along with a claim of confidentiality pursuant to Permit Condition 5.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 17	RIGHT TO ENTRY AND INSPECTION OF PERMISES: A. The Control Officer during reasonable hours, for the purpose of enforcing and administering County or SIP Rules or the Clean Air Act, or any provision of the Arizona Revised Statutes relating to the emission or control prescribed pursuant thereto, may enter every building, premises, or other place, except the interior of structures used as private residences. Every person is guilty of a petty offense under ARS §49-488 who in any way denies, obstructs or hampers such entrance or inspection that is lawfully authorized by warrant. B. The Permittee shall allow the Control Officer or his authorized representative, upon presentation of proper credentials and other documents as may be required by law, to: 1) Enter upon the Permittee's premises where a source is located or emissions-related activity is conducted, or where records are required to be kept pursuant to the conditions of the permit; 2) Have access to and copy, at reasonable times, any records that are required to be kept pursuant to the conditions of the permit; 3) Inspect, at reasonable times, any sources, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required pursuant to this permit; 4) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or other applicable requirements; and 5) To record any inspection by use of written, electronic, magnetic, and photographic media.	Standard operating procedures.	Continuous	No

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
SPECIFIC PERMIT CONDITIONS				
Section 18.A.1	ALLOWABLE EMISSION LIMITATIONS – OFFSITE SULFUR OXIDES LIMITS: The Permittee shall not emit into the ambient air any sulfur oxide in such manner and amounts as to result in ground level concentrations at any place beyond the premises on which the source is located exceeding those limits shown in Table 1. Sulfur Dioxide Ambient Concentration Limits described as follows: Averaging time 1 hour Concentration of Sulfur Dioxide is 850 µg/cubic m. Averaging time 24 hour Concentration of Sulfur Dioxide is 250 µg/cubic m. Averaging time 72 hour Concentration of Sulfur Dioxide is 120 µg/cubic m.	Standard operating procedures. Compliance demonstrated by ambient air quality modeling (Feb 98) and permitted operating scenarios.	Continuous	No
Section 18.A.2	ALLOWABLE EMISSION LIMITATIONS – OPACITY LIMITS: The Permittee shall not discharge into the ambient air from any single source of emissions any air contaminant, other than uncombined water in excess of 20 percent opacity, except as follows: a) Opacity may exceed the applicable limits established in Condition 18.A.2) for up to one hour during the start - up of switching fuels; however, opacity shall not exceed 40% for any six (6) minute averaging period in this one hour period, provided that the Control Officer finds that the owner or operator has, to the extent practicable, maintained and operated the source of emissions in a manner consistent with good air pollution control practices for minimizing emissions. The one hour period shall begin at the moment of startup of fuel switching.	RM 9 observations; standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 18.B	ALLOWABLE EMISSIONS FOR THE STEAM UNITS AND COMBUSTION TURBINES: The Permittee shall not cause, allow or permit the emission of particulate matter, caused by combustion of fuel, from any fuel burning equipment or stationary rotating machinery having a heat input rate of 4200 million Btu per hour or less in excess of the amounts calculated by the following equation: $E = 1.02\ Q^{0.769}$ where: E= the maximum allowable particulate emissions rate in pounds-mass per hour. Q= the heat output in million Btu per hour. Additional Allowable Emissions for the Steam Units: The Permittee shall not emit more than 2.2 pounds of sulfur dioxide, maximum two hours average, per million BTU heat input when combusting fuel oil.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 18.C	ALLOWABLE EMISSIONS FROM NON-RESALE GASOLINE STORAGE TANKS GREATER THAN 250 GALLONS. Vapor loss from the source at any point in time shall not exceed 10,000 ppm as methane as measured by an organic vapor analyzer or combustible gas detector.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 19.A.1	FACILITY-WIDE OPERATIONAL REQUIREMENTS: The Permittee shall combust only pipeline natural gas as defined in 40 CFR 72.2 except when combusting emergency fuel pursuant to County Rule 322 in the combustion turbines and boilers. a) If the Permittee demonstrates to the Control Officer that natural gas is not available due to a national natural gas emergency, natural gas curtailment, unavoidable interruption of supply (e.g., catastrophic pipeline failure), or other similar event; the Permittee shall be authorized to combust fuel oil with sulfur content 0.0015 percent by weight or less in the steam units and combustion turbines under such conditions as are justified. In cases where the Permittee is authorized to combust fuel oil, the Permittee shall submit monthly reports to the Control Officer detailing its efforts to obtain natural gas. When the conditions justifying the fuel oil no longer exist, the Permittee shall combust only pipeline quality natural gas. b) Combustion Units 1 and 2 and Steam Units 1 and 2 shall be exempt from County Rule 322 §§304 and 305 and §§301.1, 306.4, 401.4, and 501.4 for 36 cumulative hours of firing fuel oil per year, per unit for testing, reliability, training, and maintenance purposes.	Standard operating procedures; compliance reviews.	Continuous	No
Section 19.A.2	FACILITY-WIDE OPERATIONAL REQUIREMENTS: The Permittee shall not emit gaseous or odorous air contaminants from equipment, operations, or premises under his control in such quantities or concentrations as to cause air pollution.	Standard operating procedures; compliance reviews.	Continuous	No
Section 19.A.3	FACILITY-WIDE OPERATIONAL REQUIREMENTS: Materials including, but not limited to solvents or other volatile compounds, paints, acids, alkalies, pesticides, fertilizer and manure shall be processed, stored, used and transported in such a manner and by such means that they will not unreasonably evaporate, leak, escape or be otherwise discharged into the ambient air so as to cause or contribute to air pollution. Where means are available to reduce effectively the contribution to air pollution from evaporation, leakage or discharge, the installation and use of such control methods, devices or equipment shall be mandatory.	Standard operating procedures; compliance reviews.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 19.A.4	FACILITY-WIDE OPERATIONAL REQUIREMENTS: Where a stack, vent or other outlet is at such a level that air contaminants are discharged to adjoining property, the Control Officer may require the installation of abatement equipment or the alteration of such stack, vent, or other outlet to a degree that will adequately dilute, reduce or eliminate the discharge of air contaminants to adjoining property.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 19.B	OPERATIONAL REQUIREMENTS NON-RESALE GASOLINE STORAGE TANKS GREATER THAN 250 GALLONS: The Permittee shall prohibit concurrent delivery of gasoline to a tank with more than 1 fill pipe.	Standard operating procedures; compliance reviews.	Continuous	No
Section 19.C.1	OPERATIONAL REQUIREMENTS FOR THE GENERAC 125 HP ENGINE: The Permittee shall limit the operation of the emergency engine(s) to no more than 100 hours each per calendar year for the purposes of maintenance checks and readiness testing.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 19.C.2	OPERATIONAL REQUIREMENTS FOR THE GENERAC 125 HP ENGINE: The Permittee shall limit the total hours of operation of the emergency engine(s) to no more than 500 hours each per any twelve consecutive months including the hours listed in Condition 19.C.l). The daily trigger of Best Available Control Technology (BACT) has been exempted for the emergency generator(s).	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

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<table>
<tr><th colspan="2">Permit Terms & Conditions</th><th>Methods Used for Compliance</th><th>Compliance Status</th><th>Deviations</th></tr>
<tr><td>Section 19.C.3</td><td>OPERATIONAL REQUIREMENTS FOR THE GENERAC 125 HP ENGINE:

The emergency generator(s) shall not be used for peak shaving. The emergency generator(s) shall only be used for the following purposes:

a) For power when normal power service fails from the serving utility or if onsite electrical transmission or onsite power generation equipment fails;

b) Reliability-related activities such as engine readiness, calibration, or maintenance or to prevent the occurrence of an unsafe condition during electrical system maintenance as long as the total number of hours of the operation does not exceed 100 hours per calendar year per engine as evidenced by an installed non-resettable hour meter.</td><td>Standard operating procedures; compliance reviews; recordkeeping.</td><td>Continuous</td><td>No</td></tr>
<tr><td>Section 19.C.4</td><td>OPERATIONAL REQUIREMENTS FOR THE GENERAC 125 HP ENGINE:

The Permittee may not use any fuel that contains more than 0.05% sulfur by weight, alone or in combination with other fuels.</td><td>Standard operating procedures; compliance reviews; recordkeeping.</td><td>Continuous</td><td>No</td></tr>
<tr><td>Section 19.C.5</td><td>OPERATIONAL REQUIREMENTS FOR THE GENERAC 125 HP ENGINE:

NSPS Subpart JJJJ Emission Standards: The spark ignition emergency generators shall be certified by the engine manufacturer to meet the following emission standards.

Emission Standards (g/hp-hr)<table><tr><th>NOx</th><th>CO</th><th>THC</th></tr><tr><td>4.32</td><td>129.14</td><td>0.20</td></tr></table></td><td>Standard operating procedures; compliance reviews; recordkeeping.</td><td>Continuous</td><td>No</td></tr>
<tr><td>Section 19.C.6</td><td>OPERATIONAL REQUIREMENTS FOR THE GENERAC 125 HP ENGINE:

Fuel Limitations: The Permittee may only use natural gas, butane and propane fuel for the natural gas fueled emergency engine.</td><td>Standard operating procedures; compliance reviews; recordkeeping.</td><td>Continuous</td><td>No</td></tr>
<tr><td>Section 19.C.7</td><td>OPERATIONAL REQUIREMENTS FOR THE GENERAC 125 HP ENGINE:

New Source Performance Standards: Natural Gas Emergency Engine: If the Permittee modifies or reconstructs a stationary (natural gas fueled) spark ignition combustion engine after June 12, 2006, that engine shall comply with all applicable requirements of 40 CFR 60 Subpart JJJJ.</td><td>NA Explanatory statement of law and therefore not amendable to compliance certification.</td><td>NA</td><td>NA</td></tr>
</table>

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 19.C.8	OPERATIONAL REQUIREMENTS FOR THE GENERAC 125 HP ENGINE: The Permittee shall operate and maintain the certified SI ICE according to the manufacturer's emission-related written instructions.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 20.A.1	MONITORING REQUIREMENTS FOR THE STEAM BOILERS, UNITS 1 AND 2, AND THE COMBUSTION TURBINES, UNITS 1 AND 2: The Permittee shall meet the monitoring requirements as specified in 40 CFR 75 §§10, 11 (d), 12 (a).	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 20.A.2	MONITORING REQUIREMENTS FOR THE STEAM BOILERS, UNITS 1 AND 2, AND THE COMBUSTION TURBINES, UNITS 1 AND 2: The Permittee shall install, calibrate, maintain, and operate in accordance with Rule 245 a continuous emission monitoring system for the measurement of opacity for the steam boilers, Units 1 and 2, which meet the performance specifications of Rule 245 §303.1 except as stated in Rule 245 § 302.1a.(1) if pipeline quality natural gas is the only fuel burned. This monitoring requirement will not apply if the Permittee is able to comply with the applicable particulate matter and opacity regulations without utilization of particulate matter collection equipment and the Permittee has never been found through any administrative or judicial proceedings to be in violation of any visible emission standard of the applicable plan.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 20.A.3	MONITORING REQUIREMENTS FOR THE STEAM BOILERS, UNITS 1 AND 2, AND THE COMBUSTION TURBINES, UNITS 1 AND 2: The Permittee shall monitor for compliance with the particulate matter emissions limits of the permit by taking a visual opacity inspection of the stack emissions from each steam unit and each combustion turbine each week of operation during which that equipment was used more than 10 hours. Reading shall not be taken during start-up, shut down or any other irregularities in the operation which do not aggregate to more than 3 minutes in any 60 minute period. If emissions are visible, the Permittee shall obtain an opacity reading conducted in accordance with EPA Reference Method 9 as modified by EPA Reference Method 203B by a certified reader. This reading shall be taken within 3 days of the visible emissions and taken thereafter weekly until there are no visible emissions. If the condition causing the visible emissions is eliminated before three days have passed, and no emissions are visible, the Permittee shall not be required to conduct the certified reading. If the reading exceeds 15 percent opacity, the Control Officer may require emissions testing by other EPA approved Reference Method such as Reference Method 5 to demonstrate compliance with the particulate matter emission limits of these Permit Conditions. For the purposes of these Permit Conditions, a certified Visible Emissions reader shall mean an individual who, at the time the reading is taken, is certified according to the County Rule Appendix C Section 3.4.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 20.B.1	RECORDKEEPING REQUIREMENTS FOR THE STEAM UNITS AND COMBUSTION TURBINES: The Permittee shall maintain a file of all measurements as required by Rule 210 §302.1.d, including continuous monitoring system (CO and NOx emission records), monitoring device (operating parameter record; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR Part 75 Subpart F recorded in a permanent form.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 20.B.2	RECORDKEEPING REQUIREMENTS FOR THE STEAM UNITS AND COMBUSTION TURBINES: The Permittee shall keep all the records of the fuel supplier certification of the sulfur content of the fuel oil being combusted in each steam unit and each combustion turbine. The supplier certification shall include: a) The name of the oil supplier; b) The sulfur content of the oil from which the shipment came (or of the shipment itself); and c) The method used to determine the sulfur content of the oil.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No
Section 20.B.3	RECORDKEEPING REQUIREMENTS FOR THE STEAM UNITS AND COMBUSTION TURBINES: If the Permittee performs the sampling procedure in order to determine the sulfur content of the fuel oil, than the Permittee shall also keep the records of the location of the oil when the sample was drawn for analysis, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the facility or another location.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No
Section 20.B.4	RECORDKEEPING REQUIREMENTS FOR THE STEAM UNITS AND COMBUSTION TURBINES: The Permittee shall keep records from the pipeline quality natural gas supplier to monitor for compliance with permit condition 19.A.1).	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 20.B.5	RECORDKEEPING REQUIREMENTS FOR THE STEAM UNITS AND COMBUSTION TURBINES: The Permittee shall keep daily records of the type, sulfur content and amount of fuel used along with the hours of operation in each steam unit and each combustion turbine.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 20.B.6	RECORDKEEPING REQUIREMENTS FOR THE STEAM UNITS AND COMBUSTION TURBINES: The Permittee shall log the opacity reading conducted in accordance with EPA Reference Method 22 and log the opacity reading conducted in accordance with EPA Reference Method 9 as modified by EPA Reference Method 203B. The Permittee shall record any deviations that were less than the 3 day period which would require a certified reading. This information should include the date and time, when that reading was taken, results of the reading, name of the person who took the reading and any other related information as required by the protocol for EPA Reference Method 9 as modified by EPA Reference Method 203B or Method 22 as applicable.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 20.B.7	RECORDKEEPING REQUIREMENTS FOR THE STEAM UNITS AND COMBUSTION TURBINES: The Permittee shall maintain a log of complaints of odors detected off-site. The log shall contain a description of the complaint, date and time that the complaint was received, and if given, name and/or phone number of the complainant. The logbook shall describe what actions were performed to investigate the complaint, the results of the investigation, and any corrective actions that were taken.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

Compliance Certification

Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 20.C	MONITORING/RECORDKEEPING REQUIREMENTS FOR THE NON-RESALE GASOLINE TANKS GREATER THAN 250 GALLONS: The Permittee shall keep the following records and supporting information no less than five years from the date of such record: 1) Inspect spill containment receptacles weekly for cracks, defects, foreign material, and spilled gasoline. Records shall be maintained as specified below. 2) External fittings of the fill pipe assembly shall be inspected weekly to assure that the cap, gasket, and piping are intact and are not loose. 3) If deliveries are less than weekly, inspection and recording of the inspection at the time of each delivery will be considered an acceptable alternative to the weekly inspection and recordkeeping requirements of the rule. 4) The total amount of gasoline received each month shall be recorded by the end of the following month. 5) Weekly inspection records of the fill pipe and spill containment shall be recorded by the end of Saturday of the following week. 6) Records of the last 12 months shall be onsite and readily available to the Control Officer without delay.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 20.D	MONITORING/RECORDKEEPING REQUIREMENTS FOR THE GENERAC 125 HP ENGINE: 1) The Permittee shall maintain the following records for a period of at least five years from the date of the records and make them available to the Control Officer upon request: a) An initial one time entry listing the particular engine combustion type (compression or spark-ignition or rich or lean bum); manufacturer; model designation, rated brake horsepower, serial number and where the engine is located on the site. b) Fuel type and sulfur content of fuel; and an explanation for the use of the engine if it is used as an emergency engine. [Rule 324 §502] c) Emergency Provisions: The Permittee shall comply with all record keeping and reporting requirements of Rule 130 (Emergency Provisions) and Rule 140 (Excess Emissions) if the annual allowable hours of operation are exceeded. [Rule 130; Rule 140] d) The 12-month rolling total hours shall be calculated monthly within 28 days following the end of each calendar month by summing the hours over the most recent 12 calendar months, including hours of operation for testing, reliability, and maintenance. The hours used for testing, reliability, and maintenance shall also be calculated per calendar year within 28 days following the end of the calendar year. The Permittee shall keep this hourly report on-site for inspection or submittal upon request. [Rule 210 §302.1] e) Monitoring: The Permittee shall not operate the emergency generator(s) unless its cumulative run time meter is installed and working properly. f) Low Sulfur Oil Verification: If the Control Officer requests proof of the sulfur content of fuel burned in the engines, the Permittee shall submit fuel receipts, contract specifications, pipeline meter tickets, Material Safety Data Sheets (MSDS), fuel supplier information or purchase records, if applicable, from the fuel supplier, indicating the sulfur content of the fuel oil. In lieu of these, testing of the fuel oil for sulfur content to meet the applicable sulfur limit shall be permitted if so desired by the owner or operator for evidence of compliance. [Rule 220 §302.13] g) Maintenance: The Permittee shall retain written records of all maintenance performed on the SI ICE. [40 CFR 60.4243(a)]	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 21.A	REPORTING REQUIREMENTS FOR THE STEAM UNITS ONLY: The Permittee shall electronically report to EPA the data and information as required by 40 CFR Part 75.64 on a quarterly basis. Quarterly submittals shall include facility data, unit emission data, monitoring data, control equipment data, monitoring plans and quality assurance data and results.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 21.B	REPORTING REQUIREMENTS: The Permittee shall file a semiannual Monitoring Report and Compliance Certification no later than April 30, and shall report the monitoring and compliance status of the source during the period between October 1 of the previous year and March 31 of the current year. The second report and certification shall be submitted no later than October 31 and shall report the monitoring and compliance status of the source during the period between April 1 and September 30 of the current year. The Monitoring Report and Compliance Certification shall be sent to the Compliance Division with attention to: Compliance Division Manager and shall contain the following information at a minimum: 1) Dates on which opacity readings were taken, the test method used, and the observed opacity; 2) Fuel Supplier Certification regarding sulfur content for all fuel oil delivered during reporting period; 3) A copy of the log of complaints of odors or air pollution, and the results of investigations performed in response to odor or air pollution complaints and any corrective actions taken. 4) Monthly usage reports of each volatile surface coating related to surface coating. 5) Material list and a list of the coatings which are exempt from the volatile organic compounds content requirements. 6) a) Summary of the monthly and 12-month rolling total records of the gasoline delivered. b) Records of the inspections of the submerged fill pipe required by these Permit Conditions. 7) Any deviations from the approved Dust Control Plan. 8) A summary of the opacity readings during external blasting and blasting with baghouse, control measures utilized for abrasive blasting and dates on which any blasting was performed. 9) The dates and description of any usage of cutback and emulsified asphalt. 10) Monthly records of the amount of each coating, adhesive, solvents and any other VOC-containing materials used.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 22	TESTING REQUIREMENT: The combustion units at the current facility were constructed and operational before the current testing regulations were put into effect and are exempt from the current testing requirements.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 23.A	OTHER REQUIREMENTS – PERMIT SHIELD: Compliance with the conditions of this Permit shall be deemed compliance with the applicable requirements identified in Appendix "B" of this Permit. The Permit Shield shall not extend to minor permit revisions.	NA Explanatory statement of law and therefore not amendable to compliance certification.	NA	NA
Section 23.B	OTHER REQUIREMENTS – ACID RAIN PERMIT: 1) The Acid Rain Phase II Permit Application and Certificate of Representation signed by the Designated Representative and submitted to the Control Officer shall constitute the Permittee's Acid Rain Permit. 2) The Permittee shall comply with the Acid Rain Permit, 40 CFR Parts 72, 73, and 75, and the Acid Rain requirements of Permit Condition 6.A. 3) The relevant Conditions of this Permit and the Acid Rain Permit, including but not limited to, the Allowable Emission Limits, Operation Requirements, Monitoring/Recordkeeping Requirements, Reporting Requirements, and Testing Requirements shall constitute the Compliance Plan required by 40 CFR Part 72 Subpart D. 4) The Permittee shall hold SO2 Allowances as of the allowance transfer deadline in each Combined Cycle System compliance subaccount not less than the total annual actual emissions of SO2 for the previous calendar year from each combined Cycle System as required by the Acid Rain Program. 5) The SO2 Allowance Allocations for Affected Systems are shown in Table 2: Unit 1 2000-2009: 56; 2010 and thereafter: 40 Unit 2 2000-2009: 132; 2010 and thereafter: 129 None of these units are subject to a NOx limit pursuant to 40 CFR Part 76.	Standard operating procedures; compliance reviews.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 24	SURFACE COATING OPERATIONS: If the Permittee engages in any surface coating operations, the Permittee shall comply with all applicable conditions from County Rule 336: Surface Coating Operations.	Standard operating procedures; compliance reviews.	Continuous Term NA during this period.	No
Section 25	DEGREASERS: If the Permittee engages in any degreasing operations, the Permittee shall comply with all applicable conditions from County Rule 331: Solvent Cleaning.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 26	WIPE CLEANING: If the Permittee engages in any wipe cleaning operations, the Permittee shall comply with all applicable conditions from County Rule 331: Solvent Cleaning.	Standard operating procedures; compliance reviews.	Continuous	No
Section 27	ARCHITECTURAL COATINGS: If the Permittee applies any architectural coatings, the Permittee shall comply with the requirements of County Rule 335: Architectural Coatings.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No
Section 28.A	NON-RESALE GASOLINE STORAGE TANKS WITH CAPACITY GREATER THAN 250 GALLONS AND GASOLINE THROUGHPUT LESS THAN 120,000 GALLONS PER YEAR – ALLOWABLE THROUGHPUT: The Permittee shall limit the delivery of gasoline to the facility to less than 10,000 gallons per month and less than 120,000 gallons per year.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 28.B.1	NON-RESALE GASOLINE STORAGE TANKS WITH CAPACITY GREATER THAN 250 GALLONS AND GASOLINE THROUGHPUT LESS THAN 120,000 GALLONS PER YEAR – VOC EMISSION STANDARD: No vapor or liquid escapes are allowed through a dispensing tank's outer surfaces, nor from any of the joints where the tank is connected to pipe(s), wires, or other system. Tanks and their fittings shall be vapor tight except for the outlet of a pressure/vacuum relief valve on a dispensing tank's vent pipe. Specifically, this means that at a probe tip distance of 1 inch (2.5 cm) from a surface, no vapor escape shall exceed 1/5 of the lower explosive limit. This applies to tanks containing gasoline regardless of whether they are currently being filled, and to caps and other tank fittings.	Standard operating procedures; compliance reviews.	Continuous	No
Section 28.B.2	NON-RESALE GASOLINE STORAGE TANKS WITH CAPACITY GREATER THAN 250 GALLONS AND GASOLINE THROUGHPUT LESS THAN 120,000 GALLONS PER YEAR – LEAKAGE LIMITS-LIQUID LEAKS AND SPILLS: a) Gasoline storage and receiving operations shall be leak free. Specifically, no liquid gasoline escape of more than 3 drops per minute is allowed. This includes leaks through the walls of piping, fittings, fill hose(s), and vapor hose(s). b) All open gasoline containers shall be covered with a gasketed seal when not in use. c) There shall be no excess gasoline drainage from the end of a fill hose or a vapor hose. Specifically, not more than 2 teaspoonfuls of gasoline shall be lost in the course of a connect or disconnect process. d) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.	Standard operating procedures; compliance reviews.	Continuous	No

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Permit Terms & Conditions		Methods Used for Compliance	Compliance Status	Deviations
Section 28.B.3	NON-RESALE GASOLINE STORAGE TANKS WITH CAPACITY GREATER THAN 250 GALLONS AND GASOLINE THROUGHPUT LESS THAN 120,000 GALLONS PER YEAR – SPILL CONTAINMENT: The entire spill containment system including gaskets shall be kept vapor-tight. a) The Spill Containment Receptacle: (1) The outer surface of the spill containment receptacle shall have no holes or cracks and shall allow no vapors to pass from the dispensing tank through it to the atmosphere. (2) Spill containment receptacles shall be kept clean and free of foreign material at all times. b) If the spill containment is equipped with a passageway to allow material trapped by the containment system to flow into the interior of the dispensing tank: (1) The passageway shall be kept vapor tight at all times, except during the short period when a person opens the passageway to immediately drain material trapped by the containment system into the tank. (2) The bottom of the receptacle shall be designed and kept such that no puddles of gasoline are left after draining through the passageway has ceased. c) The dispensing tank owner/operator is responsible for assuring that before a delivery vessel leaves the premises after a delivery: (1) Any gasoline in the spill containment system and vault shall be cleaned up as expeditiously as practicable and shall be removed prior to delivery trucks leaving the site. (2) Any gasoline absorbed onto other materials shall be contained in order to minimize emissions prior to delivery trucks leaving the site.	Standard operating procedures; compliance reviews.	Continuous	No

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Section 28.B.4	NON-RESALE GASOLINE STORAGE TANKS WITH CAPACITY GREATER THAN 250 GALLONS AND GASOLINE THROUGHPUT LESS THAN 120,000 GALLONS PER YEAR – FILL PIPE: a) The tank shall be equipped with a permanent submerged fill pipe, the end of which is totally submerged when the liquid level is 6 inches from the bottom of the tank; b) Threads and gaskets shall be kept vapor tight; c) Fill pipe caps shall have a secure, intact gasket which latches completely and has no structural defects; d) The fill pipe caps may only be removed to measure the gasoline depth in the tank, deliver gasoline, or for testing, maintenance, and inspection of the vapor recovery system; e) Overfill prevention equipment shall be kept vapor tight so that no emissions from the tank can penetrate into the fill-pipe or atmosphere; f) Fill Pipe Obstructions: (1) Any type of screen or obstruction in fill-pipe assemblies shall be removed as of November 1, 1999 unless it is approved in writing by the Control Officer or is CARB-certified per Rule 353 §503.4. (2) A screen or other obstruction, allowed by Air Pollution Permit or CARB, shall be temporarily removed by the owner/operator of a dispensing tank prior to inspection by the Control Officer to allow measurements pursuant to this rule.	Standard operating procedures; compliance reviews.	Continuous	No
Section 29	ABRASIVE BLASTING OPERATIONS: If the Permittee engages in abrasive blasting activities, the Permittee shall comply with the requirements of County Rule 312: Abrasive Blasting.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No
Section 30	CUTBACK AND EMULSIFIED ASPHALT: If the Permittee applies cutback and emulsified asphalt and other bitumens to roads, parking lots, driveways or other surfaces, the Permittee shall comply with the requirements of County Rule 340: Cutback and Emulsified asphalt.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous Term NA during this period.	No
Section 31	VOLATILE ORGANIC COMPOUNDS: The Permittee shall comply with all applicable conditions from County Rule 330: Volatile Organic Compounds.	Standard operating procedures; compliance reviews; recordkeeping.	Continuous	No

Compliance Certification

I, Dennis Irvin, as Responsible Official, Plant Manager for the APS Ocotillo Power Plant, hereby certify that:

1. The applicable requirements for the Ocotillo Power Plant that are the basis of this certification are set forth in the Ocotillo Title V Permit.

2. The Ocotillo Power Plant is in compliance with the applicable requirements listed in the Ocotillo Title V Permit, and will comply with any additional requirements, if any, become applicable during the permit term.

3. The methods used to determine compliance with the listed applicable requirements are set forth in Section 4 of this permit application and in the Ocotillo Title V Permit.

4. Arizona Public Service Company will submit required semi-annual compliance certifications no later than April 30, for operations between October 1 and March 31, and the second report will be submitted no later than October 31, for operations between April 1 and September 30.

5. Based on information and belief formed after reasonable inquiry, the statement and information in the permit application are true, accurate and complete.

Dennis J Irvin Date: 9/29/2015

Dennis Irvin
Ocotillo Plant Manager

Appendix B.

Control Technology Review

Ocotillo Power Plant

Application to construct five (5) new natural gas-fired General Electric LMS100 simple cycle gas turbine generators

Appendix B.

Control Technology Review

Best Available Control Technology (BACT) analysis for the natural gas-fired General Electric LMS100 simple cycle gas turbine generators, cooling tower, emergency diesel generators, diesel fuel oil storage tank, SF_6 insulated electrical equipment, and natural gas piping systems.

Original Date:	**April, 2014**
Updated:	**September 30, 2015**

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Executive Summary

This document is a control technology review or Best Available Control Technology (BACT) analysis for the Ocotillo Power Plant Modernization Project. The location of the Ocotillo Power Plant is currently classified as a serious nonattainment area for particulate matter less than 10 microns (PM_{10}), a marginal nonattainment area for ozone, and an attainment or unclassified area for all other Prevention of Significant Deterioration (PSD) regulated pollutants.

APS is proposing to construct 5 new gas-fired combustion turbines (GTs) and associated equipment, and permanently retire the existing Ocotillo steam electric generating units 1 and 2. Based on the total potential emissions for the Project as proposed in this application and the current actual emissions of the retired Unit 1 and 2 steamers, the Project will result in an emissions increase <u>and</u> a net emissions increase in carbon monoxide (CO), particulate matter (PM), $PM_{2.5}$, and greenhouse gas (GHG) emissions that are above the PSD significant emission rates. Therefore, the Project is subject to PSD requirements for these pollutants, and this document presents the PSD BACT analyses.

The Project is not subject to NANSR requirements for PM_{10}, VOC, or NOx, and therefore no Lowest Acheivable Emission Rate (LAER) control technology analysis is required for those pollutants.

In addition to the PSD requirements, Maricopa County's Air Pollution Control Regulations (MCAPCR), Rule 241, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of NO_x or VOC emissions. Because the GTs would have maximum NO_x and VOC emissions which exceed these thresholds, this document includes the County required BACT analyses for NO_x and VOC emissions to address MCAPCR Rule 241.

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Chapter 1. Control Technology Review Methodology.

1.1 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 200.24, "best available control technology" (BACT) means:

> **200.24** **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.

1.2 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 most important issue of the BACT review is generally the economic impact. 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.

1.3 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 physical and chemical gas stream characteristics.

1.4 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[1]:

> 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.

1.1.1 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.

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

1.1.2 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:

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

1.5 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.[2]

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:[3]

> 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.

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

[3] 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).

The EAB has analyzed the redefinition of the source concept in the context of a past permitting proceeding similar to the proposed Ocotillo Modernization 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 Ocotillo, 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."[4]

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. For example, in the U.S. EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[5] 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 the Ocotillo Modernization 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.[6]

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

[5] *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 .

[6] 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 2. Project Purpose and Need.

The purposes for the Project are to provide peaking and load shaping electric capacity in the range of 25 to 500 MW (including quick ramping capability to backup renewable power and other distributed energy sources), to replace the 200MW of peak generation that will be retired at Ocotillo with cleaner units, and to provide an additional 300MW of peak generation to handle future growth. This Project has been reviewed and the Certificate of Environmental Compatibility has been approved by the Arizona Corporation Commission (ACC) after a lengthy public comment period and hearing process.

APS is continuing to add renewable energy, especially solar energy, to the electric power grid, with the goal of achieving a renewable portfolio equal to 15% of APS's total generating capacity by 2025 as mandated by the ACC. However, because renewable energy is an intermittent source of electricity, a balanced resource mix is essential to maintain reliable electric service. As of January 1, 2015, APS has approximately 1,200 MW of renewable generation and an additional 46 MW in development. Within Maricopa County and the Phoenix metropolitan area, APS has about 115 MW of solar power and there is an additional 300 – 400 MW of rooftop Photovoltaic (PV) solar systems.

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, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, 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[7]. Considering only the solar capacity in Maricopa County, the required electric generating capacity ramp rate required to back up these types of solar systems would therefore range from 165 to 310 MW per minute. The actual renewable energy load swings experienced on the APS system have also shown rapid load changes from renewable energy sources of 25 to 300 MW in very short time periods, in agreement with the estimates found in the EPRI study.

To backup the current and future renewable energy resources, the Project design requires quick start and power escalation 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 five General Electric (GE) LMS100 gas-fired simple cycle combustion turbine generators (GTs), which have the capability to meet these design needs while complying with the proposed BACT air emission limits at loads ranging from 25% to 100% of the maximum output capability of the turbines. The proposed LMS100 GTs can provide an electric power ramp rate equal to 50 MW per minute per GT which is critical for the project to meet its purpose. When all 5 proposed GTs are operating at 25% load, the entire project can provide approximately 375 MW of ramping capacity (i.e., from 125 to 500 MW) in less than 2 minutes.

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[7] 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.

Chapter 3. GT Carbon Monoxide (CO) Control Technology Review.

Carbon monoxide (CO) is emitted from simple cycle combustion turbines as a result of incomplete combustion. Therefore, the most direct approach for reducing CO emissions (and also reduce the other related pollutants) is to improve combustion. Incomplete combustion also leads to emissions of volatile organic compounds (VOC) and organic hazardous air pollutants (HAP) such as formaldehyde. CO emissions as well as VOC and organic HAP emissions may also be reduced using post combustion control systems including oxidation catalyst systems.

3.1 BACT Baseline.

There are no current State Implementation Plan (SIP) regulations or federal regulations applicable to CO or VOC emissions from these simple cycle gas turbines.

Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1 requires the application of BACT to any new stationary source which emits more than 550 lbs/day or 100 tons/yr of carbon monoxide.

3.2 STEP 1. Identify All Available Control Technologies.

Table B3-1 is a summary of CO control technologies and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database. The lowest reported emission limit is 4 ppm for an F-class, 175 MW Siemens turbine. However, this limit is only for operating loads above 70% of the maximum rated capacity of the turbine. This unit has additional CO BACT limits of 10 ppm for loads between 60% and 70%, and 150 ppm for loads less than 60%. This F-class turbine is a much larger gas turbine with a different design than the LMS100 aero derivative units, and cannot meet a single CO emission limit across the wide range of loads that the proposed Ocotillo GTs must operate.

There are also three permits with a CO emission limit of 5 ppm, all located in New Jersey. Two of these facilities utilize 68 MW Rolls Royce Trent turbines, and one utilizes GE LMS6000 gas turbines. The BACT clearinghouse database does not include descriptions of the operating load range over which this limit may apply. It does not appear that this BACT limit does not apply to the low load operating ranges between 25% and 50% over which these proposed LMS100 gas turbines are designed to operate.

Table B3-2 is a summary of CO emission limits for natural gas-fired simple cycle gas turbines from the South Coast Air Quality Management District's LAER/BACT determinations. The BACT emission limits for similar turbines range from 6 to 10 ppmdv, corrected to 15% excess oxygen. Several determinations in 2012 concluded that the use of oxidation catalysts and a CO limit of 6.0 ppmdv at 15% O_2 is BACT. The San Joaquin Valley Air Pollution Control District lists BACT for CO emissions from simple cycle gas turbines of 0.024 lb/mmBtu, equal to 10 ppmdv @ 15% O_2.

This database indicates two major control technologies used to control CO and VOC emissions, including Good Combustion Practices (GCP), and Oxidation Catalysts (OC). Included within the category of good combustion practices is Water Injection (WI), dry low NO_x (DLN) combustion, and steam injection (SI). There are several other potential advanced control technologies including catalytic combustion (such as XONON) and catalytic absorption/oxidation technology (such as SCONOx™).

Based on this review, the following technologies have potential for applicability to these turbines:

1. Good Combustion Practices (GCP), including:
   a) Steam injection (SI)
   b) Dry low NO_x (DLN) combustion, and
   c) Water Injection (WI)
2. Oxidation Catalyst (OC)
3. Catalytic Combustion and Catalytic Absorption/Oxidation (EMx or SCONOx™)

With respect to steam injection, the combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs. Therefore, steam injection is not an available control option for the LMS 100 GTs and is therefore eliminated as a control technology option[8].

With respect to Dry Low NO_x (DLN) combustion, DLN is an available option for the LMS100 GTs. However, the DLN equipped GTs produce much more CO and other products of incomplete combustion than the water injected GTs. As a result, DLN equipped GTs cannot meet the CO BACT emission limit below 75% load, while the water injected GTs can also achieve the CO BACT limit continuously down to 25% of load. Because a GT turndown to 25% load is a major design criterion for the Project to adequately backup renewable energy resources, utilizing DLN would require changing the basic purpose and design of the facility and may therefore be eliminated under Step 1 as redefining the source[9].

DLN equipped LMS100 GTs also have a lower peak electric generating capacity than the water injected units. The peak electric output at 105 ^{o}F is reduced significantly; from 109.9 MW (gross) for the water injected GTs to only 97.2 MW for the DLN equipped GTs. This is a significant reduction in peak generating and ramping capacity which directly affects the ability of the project to meet its basic design requirements, another reason for dismissal under Step 1 of BACT.

[8] The GE paper *New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™* which is available at GE's website at http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf is a 2004 paper that does indicate steam injection as a potential option. However, this paper preceded the first commercial operating date for an LMS 100 GT in June 2006. In an e-mail from Phil Tinne, GE Power & Water, to Scott E McLellan, Arizona Public Service dated May 14, 2015, Mr. Tinne states " I confirm that we have not developed steam injection for the LMS100, either for NOx control or power supplementation, thus it is not on our option list."

[9] The significant lack of turndown capability for the DLN equipped GTs also makes the DLN equipped LMS 100 GTs technically infeasible for these peaking units and therefore would be eliminated under Step 2.

TABLE B3-1. Carbon monoxide (CO) control technologies and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	CONTROL METHOD	LIMIT, ppmdv at 15% O_2
Great River Energy - Elk River Station	MN	07/01/2008	OC	4
PSEG Fossil Kearny Generating Station	NJ	10/27/2010	OC, GCP	5
Bayonne Energy Center	NJ	09/24/2009	OC	5
Howard Down Station	NJ	09/16/2010	OC	5
Arvah B. Hopkins Generating Station	FL	10/26/2004	OC	6
Cheyenne Prairie Generating Station	WY	08/28/2012	OC	6
Lonesome Creek Generating Station	ND	09/16/2013	OC	6
Pioneer Generating Station	ND	05/14/2013	OC	6
EI Colton, LLC	CA	01/10/2003	OC	6
Shady Hills Generating Station	FL	01/12/2009		6.5
FPL Manatee Plant - Unit 3	FL	04/15/2003	GCP	7.4
Progress Bartow Power Plant	FL	01/26/2007	GCP	8
FPL Martin Plant	FL	04/16/2003	GCP	8
Louisville Gas And Electric Company	KY	06/06/2003	GCP	9
Dahlberg Electric Generating Facility	GA	05/14/2010	GCP	9
Bosque County Power Plant	TX	02/27/2009	GCP	9
ODEC - Marsh Run Facility	VA	02/14/2003	GCP	9
ODEC - Louisa	VA	03/11/2003	GCP	9
ODEC -Marsh	VA	02/14/2003	GCP	9
ODEC - Louisa Facility	VA	03/11/2003	GCP	9
Fairbault Energy Park	MN	07/15/2004	GCP	10

Footnotes

OC means Oxidation Catalyst; GCP means Good Combustion Practices.

TABLE B3-2. CO emission limits for natural gas-fired simple cycle gas turbines from the South Coast Air Quality Management District's LAER/BACT determinations.

FACILITY	PERMIT DATE	TURBINE DESCRIPTION	CO LIMIT, ppmdv at 15% O_2	AVERAGING PERIOD
EI Colton, LLC	1/10/2003	GE LM6000	6.0	3-hr
Indigo Energy (Wildflower Energy LP)	7/13/2001	GE LM6000	6.0	1-hr
Los Angeles Dept of Water & Power	5/18/2001	GE LM6000	6.0	3-hr

3.3 STEP 2. Identify Technically Feasible Control Technologies.

3.3.1 Good Combustion Practices.

Good combustion practice including the use of water injection is an effective method for controlling CO and VOC emissions from these gas turbines. Water injection is the most widely used combustion control technology for aero derivative gas turbines and gas turbines 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. Injection rates for both water and steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (e.g., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

A significant advantage of water injection for these simple cycle gas turbines 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 turbines. This is especially important for these gas turbines because the Ocotillo Power Plant is located in a region with high ambient temperatures.

Since 2013, three peaking power plants consisting of 19 water-injected LMS 100 simple cycle GTs have commenced commercial operation in California. These plants include the Walnut Creek Energy Park (City of Industry, 5 units), the CPV Sentinel Energy Project (Riverside County, 8 units), and the Haynes Generating Station Repowering Project (6 units). Water injection was concluded to represent BACT for all of these GTs. In 2013, a water-injected LMS100 GT also commenced commercial operation at El Paso Electric Company's Rio Grande Power Plant in Sunland Park, New Mexico (this unit does not appear to be subject to PSD review). In addition, the Pio Pico Energy Center (San Diego County) received a PSD construction permit for 3 water-injected LMS 100 simple cycle GTs in 2013. The water-injected LMS 100 GTs have been selected as BACT for these peaking power plants because of their very high efficiency when operating in simple cycle mode, their fast start times, high turndown rates, flexible operation, and high peak electric output, especially under high ambient temperature conditions. Therefore, the water-injected LMS 100 GT is an available control option that is demonstrated, available and technically feasible for these proposed peaking duty GTs.

3.3.2 Oxidation Catalysts.

For natural gas turbines applications, the lowest CO and VOC emission levels have been achieved using oxidation catalysts installed as post combustion control systems. The typical oxidation catalyst is a rhodium or platinum (noble metal) catalyst on an alumina support material. This 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:

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

Acceptable catalyst operating temperatures range from 400 – 1,250 °F, with the optimum temperature range of 850 - 1,100 °F. Below approximately 400 ^{o}F, catalyst activity (and oxidation potential) is negligible. This temperature range is generally achievable with simple cycle GTs except at low load startup and shutdown conditions. Oxidation catalysts have the potential to achieve approximately 90% reductions in "uncontrolled" CO emissions at steady state operation.

3.3.3 Catalytic Combustion.

Catalytic combustion involves the use of a catalyst to reduce combustion temperatures while increasing combustion efficiency. In a catalytic combustor, fuel and air are premixed and passed through a catalyst bed. In the bed, the mixture oxidizes at reduced temperatures. The improved combustion efficiency from the catalyst has the potential to reduce CO formation to approximately 5 ppm. However, the cooler combustion temperatures would decrease the Carnot efficiency of the turbines, since the efficiency for converting heat into mechanical energy is determined by the temperature difference between heat source and sink. The reduced unit efficiency is expected to be approximately 15%.

Catalytic combustion has the potential for application to most combustor types and fuels. However, the catalyst has a limited operating temperature and pressure range, and the catalyst has the potential to fail when subjected to the extreme temperature and pressure cycles that occur in simple cycle gas turbines. Commercial acceptance of catalytic combustion by gas turbine manufacturers and by power generators has been slowed by the need for durable substrate materials. Of particular concern is the need for catalyst substrates which are resistant to thermal gradients and thermal shock.[10]

Catalytic combustors have not been commercialized for industrial gas turbines. Much of the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. Catalytica, Inc., (now owned by Renegy) developed Xenon Cool Combustion, a catalytic technology that combusts fuel flamelessly. Other company's such as Precision Combustion Inc. and Catacel™ have patented technologies for catalytic combustors for gas turbines. However, we are not aware of any technologies commercially available for large industrial turbines, and General Electric does not supply the LMS100 turbines with catalytic combustors. Therefore, this technology is not technically feasible for these GTs.

3.3.4 EMx™ Catalytic Absorption/Oxidation (SCONOx™).

EMx™ Catalytic Absorption/Oxidation (the second-generation of the SCONOx™ NOx Absorber technology), available through EmeraChem, 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

[10] R.E. Hayes and S.T. Kolaczkowski, *Introduction to Catalytic Combustion* (Amsterdam: Gordon and Breach Science Publishers, 1997); E.M. Johansson, D. Papadias, P.O. Thevenin, A.G. Ersson, R. Gabrielsson, P.G. Menon, P.H. Bjornbom and S.G. Jaras, "*Catalytic Combustion for Gas Turbine Applications*," Catalysis 14 (1999): 183-235.

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.

Because the operation of EMx™ to oxidize CO to CO_2 is similar to the use of an oxidation catalyst, there is effectively no difference between EMx™ and an oxidation catalyst in terms of CO control. Therefore, EMx™ and an oxidation catalyst may be treated as the same technology for CO control.

3.4 STEP 3. Rank the Technically Feasible Control Technologies.

Based on the above analysis, the use of Good Combustion Practices (GCP), including water injection, and the use of oxidation catalysts as a post combustion control system are technically feasible control options. Given that the lowest BACT emission limit identified cannot be achieved at loads less than 70%, and that the Ocotillo GTs must operate over a wide range of loads from 25% to 100% of the rated turbine capacity, Table B3-3 summarizes the technically feasible CO control technologies and expected achievable emission rates for these GTs.

TABLE B3-3. Achievable emission rates for technically feasible CO control technologies.

Control Option	Emission Rate, ppmdv at 15% O_2	Averaging Period
Good Combustion Practices plus Oxidation Catalysts	6.0	3-hour
Good Combustion Practices	20.0	3-hour

3.5 STEP 4. Evaluate the Most Effective Controls.

The use of good combustion practices in combination with oxidation catalysts would achieve the greatest reductions in CO (and VOC) emissions. Although the use of oxidation catalysts would achieve the greatest reductions in CO (and VOC) emissions from these GTs, the use of oxidation catalysts would increase operating costs and reduce the thermal efficiency of these GTs by increasing auxiliary power requirements and by increasing back pressure against the GT exhaust which reduces power output. However, the reduced power output is expected to be less than 1% of the gross output of these GTs.

3.6 STEP 5. Proposed Carbon Monoxide (CO) BACT Determination.

Based on this analysis, APS has concluded that the use of good combustion practices (water injection) in combination with the use of oxidation catalysts represents the best available control technology (BACT) for the control of CO emissions from the proposed GE LMS100 simple-cycle gas turbines. APS proposes the following limits as BACT for the control of CO emissions from the GTs:

1. Carbon monoxide (CO) emissions may not exceed 6.0 parts per million, dry, volume basis (ppmdv), corrected to 15% O_2, based on a 3-hour average, when operated during periods other than startup/shutdown and tuning/testing mode.

Chapter 4. GT Nitrogen Oxides (NO_x) Control Technology Review.

Based on the PSD and NANSR applicability analysis in Chapter 4 of the construction permit application, the proposed Project will not trigger either PSD BACT or NANSR LAER requirements. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of nitrogen oxides (NO_x). Based on the emission limits in this application, the proposed new GTs would have maximum daily NO_x emissions (based on continuous, full load operation of all 5 GTs combined) in excess of these thresholds. Therefore, these GTs are subject to Rule 241, Section 301.1 and a BACT analysis has been performed.

In accordance with Maricopa County Air Quality Department's memorandum "REQUIREMENTS, PROCEDURES AND GUIDANCE IN SELECTING BACT and RACT", revised July, 2010, section 8, "To streamline the BACT selection process, the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above." The following is an analysis of recent NO_x BACT determinations in California. APS proposes a BACT level which reflects these NOx BACT determinations.

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.

4.1 BACT Baseline.

4.1.1 Standards of Performance for Stationary Gas turbines, 40 CFR Part 60, Subpart KKKK.

The standards of performance for stationary gas turbines under 40 CFR Part 60, Subpart KKKK regulate emissions from these GTs and are incorporated by reference in County Rule 360 § 301.84. Each of the proposed new natural gas-fired GE Model LMS100 simple cycle gas turbines has a maximum design heat input capacity of 970 mmBtu per hour. The applicable standards in 40 CFR Part 60, Subpart KKKK, Table 1 are summarized below.

Excerpts from Table 1 to 40 CFR Part 60, Subpart KKKK: NO_x emission limits for new stationary gas turbines.

Gas turbine type	Gas turbine heat input at peak load (HHV)	NO_x emission standard
New, modified, or reconstructed turbine firing natural gas.	Greater than 850 mmBtu/hr	15 ppm at 15 percent O_2 or 0.43 lb/MWh

4.2 BACT Control Technology Determinations.

Table B4-1 is a summary of NO_x emission limits for similar simple cycle gas turbines. These facilities and emission limits are from the South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Air Quality District (SJVACD), the Bay Area Air Quality Management District (BAAQMD), and the U.S. EPA's RACT/BACT/LAER Clearinghouse. The most stringent NO_x emission limit for similar simple cycle gas turbines is 2.5 ppmdv at 15% O_2, based on a 1-hour average.

It is important to limit the review of BACT limits to similar sized simple-cycle gas turbines. Combined cycle GTs are not feasible for the Ocotillo Modernization Project because combined cycle GTs would not meet the basic purpose and need of the Project for peaking generation (see additional discussion in Section 7.5.2.3).

4.3 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. Good Combustion Practices (GCP), including:
   a) Steam injection (SI),
   b) Dry low NO_x (DLN) combustion, and
   c) Water Injection (WI)
2. Selective Catalytic Reduction (SCR), including hot SCR
3. EMx™ Catalytic Absorption process (EMx or SCONOx™)
4. Selective non-catalytic reduction (SNCR).

With respect to steam injection, as previously noted in Section 3.2 the combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs. Therefore, steam injection is not an available control option for the LMS 100 GTs and may be eliminated as a control technology option.

Dry Low NO_x (DLN) combustion is available for the LMS100 GTs and under certain operating conditions can achieve the same NOx emission rate as water injection, equal to a GT exhaust prior to the SCR systems of 25 ppmdv at 15% O_2. However, while water injected LMS100 GTs can achieve the NO_x emission rate of 25 ppm continuously down to 25% of load, the DLN equipped units cannot achieve this NO_x emission rate at loads below 50% of load. Furthermore, the DLN equipped GTs produce much more carbon monoxide (CO) and other products of incomplete combustion than the water injected GTs. As a result, the DLN equipped GTs can only meet the CO BACT emission limit down to 75% load, while the water injected GTs can also achieve the CO BACT limit continuously down to 25% of load. Because a GT turndown to 25% 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 dismissed under Step 1 as redefining the source. In addition, the significant lack of turndown capability for the DLN equipped GTs makes the DLN equipped LMS100 GTs technically infeasible for these peaking units. Therefore, even if DLN were retained in Step 1, DLN would be dismissed under Step 2 as technically infeasible.

DLN equipped LMS100 GTs also have a lower peak electric generating capacity than the water injected units. The peak electric output at 105 ^{o}F is reduced significantly; from 109.9 MW (gross) for the water injected GTs to only 97.2 MW for the DLN equipped GTs. This is a significant reduction in peak generating and ramping capacity which directly affects the ability of the project to meet its basic design requirements, another reason for dismissal under Step 1 of BACT.

Since 2013, three peaking power plants consisting of 19 water-injected LMS 100 simple cycle GTs have commenced commercial operation in California. These plants include the Walnut Creek Energy Park (City of Industry, 5 units), the CPV Sentinel Energy Project (Riverside County, 8 units), and the Haynes Generating Station Repowering Project (6 units). Water injection was concluded to represent BACT for all of these GTs. In 2013, a water-injected LMS100 GT also commenced commercial operation at El Paso Electric Company's Rio Grande Power Plant in Sunland Park, New Mexico (this unit does not appear to be subject to PSD review). In addition, the Pio Pico Energy Center (San Diego County) received a PSD construction permit for 3 water-injected LMS 100 simple cycle GTs in 2013. The water-injected LMS 100 GTs have been selected as BACT for these peaking power plants because of their very high efficiency when operating in simple cycle mode, their fast start times, high turndown rates, flexible operation, and high peak electric output, especially under high ambient temperature conditions. Therefore, the water-injected LMS 100 GT is an available control option that is demonstrated, available and technically feasible for these proposed peaking duty GTs.

As noted in the CO control technology review, catalytic combustors have not been commercialized for industrial gas turbines. We are not aware of any technologies commercially available for large industrial turbines, and General Electric does not supply the LMS100 turbines with catalytic combustors. Therefore, this technology is also not technically feasible for these GTs.

TABLE B4-1. Recent NO_x BACT limits for simple-cycle, natural gas-fired gas turbines.

Facility	State	Permit Date	Control	NO_X Limit, ppm at 15% O_2	Averaging Period
Pio Pico Energy Center	CA	Nov 2012	WI and SCR	2.5	1-hr
Walnut Creek Energy Park	CA	May 2011	WI and SCR	2.5	1-hr
TID Almond 2 Power Plant	CA	Dec 2010	WI and SCR	2.5	1-hr
PSEG Kearny Gen. Station	NJ	Oct 2010	SCR	2.5	
Howard Down Station	NJ	Sep 2010	SCR	2.5	
Canyon Power Plant	CA	Mar 2010	WI and SCR	2.5	60 min
El Cajon Energy	CA	Dec 2009	WI and SCR	2.5	1-hr
Orange Grove Energy	CA	Dec 2008	WI and SCR	2.5	1-hr
Miramar Energy Facility II	CA	Nov 2008	WI and SCR	2.5	3-hr
Escondido Energy Center	CA	Jul 2008	WI and SCR	2.5	1-hr
Starwood Power – Midway	CA	Jan 2008	WI and SCR	2.5	1-hr
Panoche Energy	CA	Dec 2007	WI and SCR	2.5	1-hr
Niland Power Plant	CA	Oct 2006	WI and SCR	2.5	1-hr
El Colton	CA	Jan 2003	SCR	3.5	3-hr
Lambie Energy Center	CA	Dec 2002	SCR	2.5	3-hr
CalPeak Power El Cajon	CA	Jun 2001	SCR	3.5	1-hr
Lonesome Creek Gen. Station	ND	Sep 2013	SCR	5	
Pioneer Generating Station	ND	May 2013	SCR	5	
Cheyenne Prairie Gen. Station	WY	Aug 2012	SCR	5	

Footnotes

WI means water injection; SCR means selective catalytic reduction.

4.3.1 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 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 gas turbines, the use of SCR is expected to reduce NO_x emissions by 80 - 90%. This reduction range would equate to emission rates of 2.5 to 5 ppm.

4.3.2 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 a SNCR system is the ability to contact the NO_x with the reagent as the concentration decreases 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 gas turbines. 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.

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

EMx™ Catalytic Absorption/Oxidation (the second-generation of the SCONOx™ NOx Absorber technology), available through EmeraChem, 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 LMS100 gas turbines.

4.4 Proposed NO_x BACT Determination.

APS has concluded that the use of good combustion practices (water injection) in combination with the use of selective catalytic reduction (SCR) represents the best available control technology (BACT) for the control of NO_x emissions from the proposed GE LMS100 simple-cycle gas turbines. This BACT determination is the same as BACT determinations that have been approved by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD.

Based on this analysis, APS proposes the following limits as BACT for the control of NO_x emissions from the new GTs:

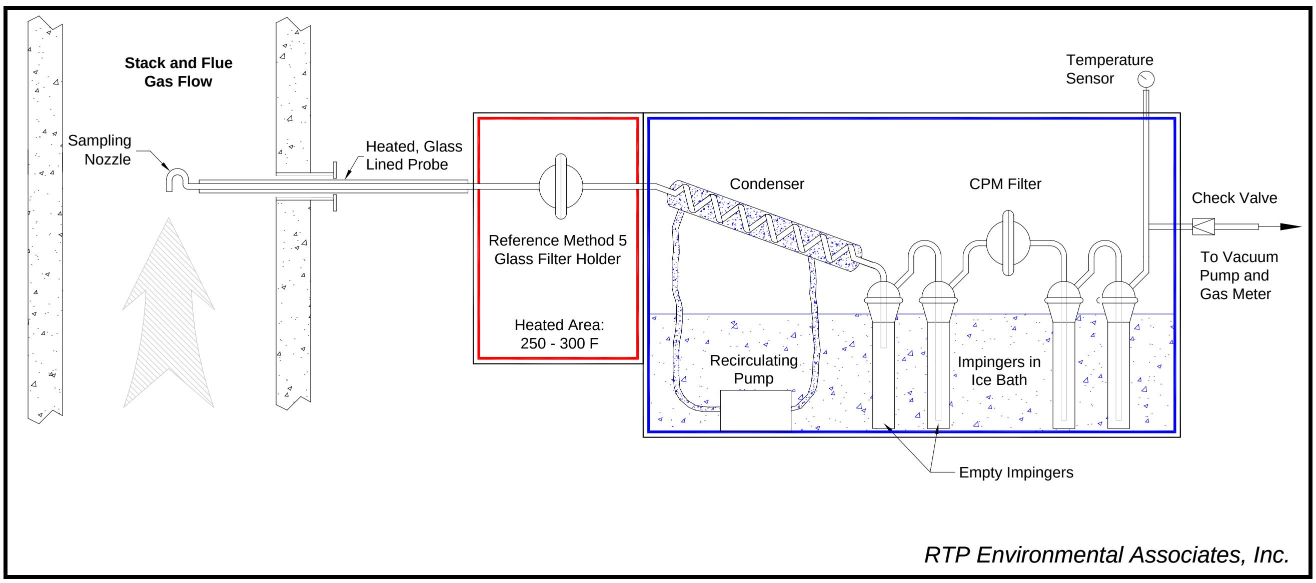
1. Nitrogen oxide (NO_x) emissions may not exceed 2.5 parts per million, dry, volume basis (ppmdv), corrected to 15% O_2, based on a 3-hour average, when operated during periods other than startup/shutdown and tuning/testing mode.

Chapter 5. GT Particulate Matter (PM) 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 gas turbines 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 GTs 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 GTs is 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 or17 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 B5-1. Reference Method 5 and Reference Method 202 sample train.



5.1 BACT Baseline.

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

5.2 STEP 1. Identify All Available Control Technologies.

Table B5-1 is a summary of PM control technologies and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database. Note that of the 32 emission limits from the U.S. EPA's RBLC database summarized in Table B5-1, 23 of the permitted emission limits (72% of the permitted sources) are stated as a mass emission rate, expressed in pounds of PM per hour. The available technologies for the control of PM emissions from natural gas-fired gas turbines identified in this database includes the use of good combustion practices and low ash / low sulfur fuels as the PM control technologies used in practice. Good combustion practices include dry low NO_x (DLN) combustion and water injection.

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

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

With respect to steam injection, as noted in Section 3.2 the combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs. Therefore, steam injection is not an available control option for the LMS 100 GTs and is therefore eliminated as a control technology option.

Dry Low NO_x (DLN) combustion is available for the LMS100 GTs. However, as previously discussed in Sections 3.2 and 4.3, utilizing DLN would require changing the basic purpose and design of the facility, and is therefore properly dismissed under Step 1 as redefining the source. In addition, the significant lack of turndown capability for the DLN equipped GTs makes the DLN equipped LMS100 GTs technically infeasible for these peaking units, and DLN would also be dismissed under Step 2 as technically infeasible.

Gas turbines are internal combustion engines. Numerous other PM control systems are also 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 gas turbines. 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 primarily for solid fuel-fired boilers.

The lowest reported BACT emission limit, stated in equivalent lb/mmBtu, is 0.0049 lb/mmBtu for the Michoud Electric Generating Plant. This proposed unit was a phased combustion turbine project consisting of 175 MW F-class gas turbines which were ultimately intended to operate in combined cycle mode. These turbines were first permitted to operate in simple cycle mode without SCR or oxidation catalysts. Therefore, booth the size of the turbines and the lack of control systems make renders this BACT entry irrelevant to the Ocotillo LMS100 BACT analysis, since SCR and oxidation catalysts are potential sources of PM emissions. Finally, this project was never constructed.

TABLE B5-1. Recent PM BACT limits for simple-cycle, natural gas-fired gas turbines.

Facility	State	Permit Date	Through-put	Unit	Permit Limit, as Stated		Equivalent Limit (calculated) lb/mmBtu
					Limit	Units	
Michoud Electric Gen. Plant	LA	Oct-04	1,595	mmBtu/hr	7.85	lb/hr	0.0049
Pio Pico Energy Center	CA	Feb-14	300	MW	0.0053	lb/mmBtu	0.0053
Goodsprings Compressor Station	NV	May-06	98	mmBtu/hr	0.0066	lb/mmBtu	0.0066
Dayton Power and Light Company	OH	Mar-06	1,115	mmBtu/hr	8.0	lb/hr	0.0072
Sabine Pass LNG Terminal	LA	Dec-11	286	mmBtu/hr	2.1	lb/hr	0.0073
Warren Peaking Power Facility	MS	Jan-03	960	mmBtu/hr	7.0	lb/hr	0.0073
R.M. Heskett Station	ND	Feb-13	986	mmBtu/hr	7.3	lb/hr	0.0074
Bayonne Energy Center	NJ	Sep-09	603	mmBtu/hr	5.0	lb/hr	0.0083
Western Farmers Elec. Anadarko	OK	Jun-08	463	mmBtu/hr	4.0	lb/hr	0.0086
Moselle Plant	MS	Dec-04	1,143	mmBtu/hr	10.0	lb/hr	0.0087
Calcasieu Plant	LA	Dec-11	1,900	mmBtu/hr	17.0	lb/hr	0.0089
SMEPA - Silver Creek Generating	MS	May-03	1,109	mmBtu/hr	10.0	lb/hr	0.0090
Fairbault Energy Park	MN	Jul-04	1,663	mmBtu/hr	0.010	lb/mmBtu	0.0100
Bosque County Power Plant	TX	Feb-09	170	MW	0.010	lb/mmBtu	0.0100
South Harper Peaking Facility	MO	Dec-04	1,455	mmBtu/hr	15.25	lb/hr	0.0105
Rincon Power Plant	GA	Mar-03	172	MW	0.011	lb/mmBtu	0.0110
ODEC - Louisa Facility	VA	Mar-03	1,624	mmBtu/hr	18.0	lb/hr	0.0111
ODEC – Louisa	VA	Mar-03	1,624	mmBtu/hr	18.0	lb/hr	0.0111
ODEC - Louisa Facility	VA	Mar-03	901	mmBtu/hr	10.0	lb/hr	0.0111
ODEC – Louisa	VA	Mar-03	901	mmBtu/hr	10.0	lb/hr	0.0111
Pioneer Generating Station	ND	May-13	451	mmBtu/hr	5.4	lb/hr	0.0120
CPV St Charles	MD	Nov-08			0.012	lb/mmBtu	0.0120
Lonesome Creek Gen. Station	ND	Sep-13	412	mmBtu/hr	5.0	lb/hr	0.0121
Texas Genco Units 1 and 2	TX	Sep-05	550	mmBtu/hr	7.0	lb/hr	0.0127

5.3 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.

5.3.1 Low Ash / Low Sulfur Fuel.

PM, PM_{10}, and $PM_{2.5}$ emissions from gas turbines 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 gas turbines, 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.

5.3.2 Post Combustion PM Control Systems.

As noted in Step 1, gas turbines 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 gas turbines. 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 gas turbines, 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 these gas turbines.

5.4 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. The use of this control is expected to achieve a

PM, PM_{10}, and $PM_{2.5}$ emission rate in the range of 0.0053 to 0.0066 lb/mmBtu of heat input (the two lowest relevant emission limits listed in Table B4-1).

5.5 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.

5.6 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 LMS100 simple-cycle gas turbines. The lowest emission limits reported in EPA's RACT/BACT/LAER database for simple cycle GTs range from 0.0053 to 0.0066 lb/mmBtu. Using the full load heat input rate for the Ocotillo LMS100 GTs of 970 mmBtu/hr, these reported emission limits range from 5.0 to 6.2 lb/hr.

The lowest report emission limit is for the Pio Pico Energy Center (PPEC), and is based on a recent BACT determination by EPA Region 9. Region 9 originally established the PM_{10} and $PM_{2.5}$ 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. EPA’s revised BACT analysis concluded that a BACT emission limit of 0.0055 lb/mmBtu would be appropriate. An emission rate of 0.0055 lb/mmBtu is equal to a mass emission rate of 5.34 lb/mmBtu at the rated heat input of 970 mmBtu per hour for the proposed GTs. However, the applicant requested a BACT limit of 0.0053 lb/mmBtu, which EPA accepted as the final permit 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.

Because the GTs have high excess oxygen levels, and because the GTs will be equipped with oxidation catalysts, it is possible that relatively high percentages of SO_2 may be converted to SO_3. We have estimated a 10% conversion rate on a mass basis, equal to a potential sulfuric acid mist emission rate of 0.06 lb/hr. As noted above, EPA's revised BACT analysis for Pio Pico concluded that a total PM BACT emission limit of 0.0055 lb/mmBtu would be appropriate. An emission rate of 0.0055 lb/mmBtu is equal to a mass emission rate of 5.34 lb/hr at the rated heat input of 970 mmBtu per hour for the proposed GTs. The addition of the estimated Ocotillo sulfuric acid mist emission rate of 0.06 lb/hr to the Pio Pico total PM emission rate results in a total PM emission rate of 5.4 lb/hr.

Given that sulfur content in natural gas fuel varies by region and will also vary over time, and allowing for variability in test results over the long-term operating life of the proposed GTs, APS proposes the following BACT emission limit for the control of particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions from the new GTs:

1. Particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions may not exceed 5.4 pounds per hour (lb/hr), based on a 3-hour average.

Chapter 6. GT Volatile Organic Compound (VOC) Control Technology Review.

Based on the PSD and NANSR applicability analyses in Chapter 4 of the construction permit application, the proposed Project will not trigger BACT or LAER control technology review requirements. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of VOC emissions. Based on the emission limits in this application, the proposed new GTs would have maximum daily VOC emissions in excess of these thresholds. Therefore, the following BACT analysis is being conducted to comply with Maricopa County Rule 241, Section 301.1.

In accordance with Maricopa County Air Quality Department's memorandum "REQUIREMENTS, PROCEDURES AND GUIDANCE IN SELECTING BACT and RACT", revised July, 2010, section 8, "To streamline the BACT selection process, the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above." The following is an analysis of recent VOC BACT determinations in California. APS proposes a BACT level which reflects these VOC BACT determinations.

Like CO emissions, VOC is emitted from simple cycle gas turbines as a result of incomplete combustion. Therefore, the most direct approach for reducing VOC emissions (and also reduce the other related pollutants) is to improve combustion. Incomplete combustion also leads to emissions of organic hazardous air pollutants (HAP) such as formaldehyde. VOC and organic HAP emissions may also be reduced using post combustion control systems including oxidation catalyst systems.

6.1 BACT Baseline.

Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of VOC emissions. Based on the emission limits in this application, the proposed new GTs would have maximum daily VOC emissions of 37 tons per year.

6.2 BACT Control Technology Determinations.

Table B6-1 is a summary of VOC emission limits for similar simple cycle gas turbines. These facilities and emission limits are from the South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Air Quality District (SJVACD), the Bay Area Air Quality Management District (BAAQMD), and the U.S. EPA's RACT/BACT/LAER Clearinghouse. The BAAQMD identifies BACT for POCs of 2.0 ppmdv at 15% O_2. However, several permits that have been issued since 2010 have limits of 3 to 5 ppmdv at 15% O_2.

TABLE B6-1. Recent VOC BACT limits for simple-cycle, natural gas-fired gas turbines.

Facility	State	Permit Date	Control	VOC Limit, ppm at 15% O_2	Averaging Period
Walnut Creek Energy Park	CA	May 2011	OC	2	1-hr
PSEG Kearny Generating Station	NJ	Oct 2010	OC	4	
Sun Valley Energy Project	CA		OC	2	1-hr
El Cajon Energy	CA	Dec 2009	OC	2	1-hr
CPV Sentinel Energy Project	CA		OC	2	1-hr
Escondido Energy Center	CA	Jul 2008	OC	2	1-hr
Dahlberg Combustion Turbine Electric Generating Plant	GA	May 2010	OC	5	
El Colton	CA	Jan 2003	OC	2	
Riverview Energy Center	CA		OC	2	1-hr
Cheyenne Prairie Gen. Station	WY	Aug 2012	OC	3	

Footnotes

OC means oxidation catalyst.

6.3 Available Control Technologies.

Based on this review, the following VOC controls have potential for applicability to these GTs:

1. Good Combustion Practices (GCP), including:
   a) Steam injection (SI)
   b) Dry low NO_x (DLN) combustion, and
   c) Water Injection (WI)
2. Oxidation Catalyst (OC)
3. Catalytic Combustion and Catalytic Absorption/Oxidation (EMx or SCONOx™)

With respect to steam injection, as noted in Section 3.2 the combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs.   Therefore, steam injection is not an available control option for the LMS 100 GTs and is therefore eliminated as a control technology option.

Dry Low NO_x (DLN) combustion is available for the LMS100 GTs. However, as previously discussed in Sections 3.2 and 4.3, utilizing DLN does not meet the basic purpose and design of the facility, and is therefore properly dismissed under Step 1 as redefining the source. In addition, the significant lack of turndown capability for the DLN equipped GTs makes the DLN equipped LMS100 GTs technically infeasible for these peaking units, and DLN DLN would also be dismissed under Step 2 as technically infeasible.Good Combustion Practices.

Good combustion practices including the use of water injection is an effective method for controlling CO and VOC emissions from these gas turbines. Water injection is the most widely used combustion control technology for aero derivative gas turbines and gas turbines 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. Injection rates for both water and steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (e.g., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

A significant advantage of water injection for these simple cycle gas turbines 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 turbines. This is especially important for these gas turbines because the Ocotillo Power Plant is located in a region with high ambient temperatures.

Since 2013, three peaking power plants consisting of 19 water-injected LMS 100 simple cycle GTs have commenced commercial operation in California. These plants include the Walnut Creek Energy Park (City of Industry, 5 units), the CPV Sentinel Energy Project (Riverside County, 8 units), and the Haynes Generating Station Repowering Project (6 units). Water injection was concluded to represent BACT for all of these GTs. In 2013, a water-injected LMS100 GT also commenced commercial operation at El Paso Electric Company's Rio Grande Power Plant in Sunland Park, New Mexico (this unit does not appear to be subject to PSD review).   In addition, the Pio Pico Energy Center (San Diego County) received a PSD construction permit for 3 water-injected LMS 100 simple cycle GTs in 2013. The water-injected LMS 100 GTs have been selected as BACT for these peaking power plants because of their very high efficiency when operating in simple cycle mode, their fast start times, high turndown rates, flexible operation, and high peak electric output, especially under high ambient temperature conditions. Therefore, the water-injected LMS 100 GT is an available control option that is demonstrated, available and technically feasible for these proposed peaking duty GTs.

6.3.1 Oxidation Catalysts.

For natural gas turbines applications, the lowest CO and VOC emission levels have been achieved using oxidation catalysts installed as post combustion control systems. The typical oxidation catalyst is a rhodium or platinum (noble metal) catalyst on an alumina support material. This 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:

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

Acceptable catalyst operating temperatures range from 400 – 1,250 °F, with the optimum temperature range of 850 - 1,100 °F. Below approximately 400 °F, catalyst activity (and oxidation potential) is negligible. This temperature range is generally achievable with simple cycle gas turbines except at low load startup and shutdown conditions. Oxidation catalysts have the potential to achieve approximately 90% reductions in "uncontrolled" CO emissions at steady state operation. VOC reduction capabilities are less, typically 50 to 60% reduction.

6.3.2 Catalytic Combustion.

Catalytic combustion involves the use of a catalyst to reduce combustion temperatures while increasing combustion efficiency. In a catalytic combustor, fuel and air are premixed and passed through a catalyst bed. In the bed, the mixture oxidizes at reduced temperatures. The improved combustion efficiency has the potential to reduce CO formation to approximately 5 ppm, and is expected to also reduce VOC emissions. However, the cooler combustion temperatures would decrease the Carnot efficiency of the turbines, since the efficiency for converting heat into mechanical energy is determined by the temperature difference between heat source and sink. The reduced efficiency is expected to be approximately 15%.

Catalytic combustion has the potential for application to most combustor types and fuels. However, the catalyst has a limited operating temperature and pressure range, and the catalyst has the potential to fail when subjected to the extreme temperature and pressure cycles that occur in simple cycle gas turbines. Commercial acceptance of catalytic combustion by gas turbine manufacturers and by power generators has been slowed by the need for durable substrate materials. Of particular concern is the need for catalyst substrates which are resistant to thermal gradients and thermal shock.[11]

Catalytic combustors have not been commercialized for industrial gas turbines. Much of the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. Catalytica, Inc., (now owned by Renegy) developed Xenon Cool Combustion, a catalytic technology that combusts fuel flamelessly. Other company's such as Precision Combustion Inc. and Catacel™ have patented technologies for catalytic combustors for gas turbines. However, we are not aware of any technologies commercially available for large industrial turbines, and General Electric does not supply the LMS100 turbines with catalytic combustors. Therefore, this technology is not technically feasible for these GTs.

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[11] R.E. Hayes and S.T. Kolaczkowski, *Introduction to Catalytic Combustion* (Amsterdam: Gordon and Breach Science Publishers, 1997); E.M. Johansson, D. Papadias, P.O. Thevenin, A.G. Ersson, R. Gabrielsson, P.G. Menon, P.H. Bjornbom and S.G. Jaras, "*Catalytic Combustion for Gas Turbine Applications*," Catalysis 14 (1999): 183-235.

6.3.3 EMx™ Catalytic Absorption/Oxidation (SCONOx™).

EMx™ Catalytic Absorption/Oxidation (the second-generation of the SCONOx™ NOx Absorber technology), available through EmeraChem, 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.

Because the operation of EMx™ to oxidize VOC to CO_2 and water is essentially identical to the use of an oxidation catalyst, there is effectively no difference between EMx™ and an oxidation catalyst in terms of CO and VOC control. Therefore, EMx™ and an oxidation catalyst may be treated as the same technology for VOC control.

6.4 Proposed VOC BACT Determination.

APS has concluded that the use of good combustion practices (water injection) in combination with the use of oxidation catalyst systems (OC) represents the best available control technology (BACT) for the control of VOC emissions from the proposed GE LMS100 simple-cycle gas turbines. This BACT determination is the same as BACT determinations that have been approved by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD.

Based on this analysis, APS proposes the following limits as BACT for the control of VOC emissions from the new GTs:

1. Volatile organic compound (VOC) emissions may not exceed 2.0 parts per million, dry, volume basis (ppmdv), corrected to 15% O_2, based on a 3-hour average, when operated during periods other than startup/shutdown and tuning/testing mode.

Chapter 7. GT 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.

7.1 Project Operational Requirements.

The purposes for the Project are to provide peaking and load shaping electric capacity in the range of 25 to 500 MW (including quick ramping capability to backup renewable power and other distributed energy sources), to replace the 200MW of peak generation that will be retired at Ocotillo with cleaner units, and to provide an additional 300MW of peak generation to handle future growth. This Project has been reviewed and the Certificate of Environmental Compatibility has been approved by the Arizona Corporation Commission (ACC) after a lengthy public comment period and hearing process.

APS is continuing to add renewable energy, especially solar energy, to the electric power grid, with the goal of achieving a renewable portfolio equal to 15% of APS's total generating capacity by 2025 as mandated by the ACC. However, because renewable energy is an intermittent source of electricity, a balanced resource mix is essential to maintain reliable electric service. As of January 1, 2015, APS has approximately 1,200 MW of renewable generation and an additional 46 MW in development. Within Maricopa County and the Phoenix metropolitan area, APS has about 115 MW of solar power and there is an additional 300 – 400 MW of rooftop Photovoltaic (PV) solar systems.

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, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, 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[12]. Considering only the solar capacity in Maricopa County, the required electric generating capacity ramp rate required to back up these types of solar systems would therefore range from 165 to 310 MW per minute. The actual renewable energy load swings experienced on the APS system have also shown rapid load changes from renewable energy sources of 25 to 300 MW in very short time periods, in agreement with the estimates found in the EPRI study.

To backup the current and future renewable energy resources, the Project design requires quick start and power escalation 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 five General Electric (GE) LMS100 gas-fired simple cycle combustion turbine generators (GTs), which have the capability to meet these design needs while complying with the proposed BACT air emission limits at loads ranging from 25% to 100% of the maximum output capability of the turbines. The proposed LMS100 GTs can provide an electric power ramp rate equal to 50 MW per minute per GT which is critical for the project to meet its purpose. When all 5 proposed GTs are operating at 25% load, the entire project can provide approximately 375 MW of ramping capacity (i.e., from 125 to 500 MW) in less than 2 minutes.

[12] 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.

7.2 Potential Greenhouse Gas (GHG) Emissions.

GHG emissions from natural gas-fired gas turbines 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 53.02 kg per mmBtu, equal to 116.6 pounds per million Btu, based on the higher heating value (HHV) of natural gas.

Methane (CH_4) emissions result from incomplete combustion. 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). Methane emissions may also result from natural gas fuel leaks which may occur from valves and piping, and also during maintenance and operation of the GTs.

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).

Potential GHG emissions for each gas turbine based on the proposed operating limits in this permit application are summarized in Tables B7-1, B7-2, and B7-3. From Table B7-3, CO_2 emissions account for more than 99.9% of the total GHG emissions. ***Because CO_2 emissions account for the vast majority of GHG emissions from these gas turbines, this control technology review for GHG emissions will focus on CO_2 emissions.***

7.3 BACT Baseline.

On August 3, 2015, the U.S. EPA announced the final Clean Power Plan which will regulate GHG emissions from new and existing power plants. 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 combustion turbines. Subpart TTTT is applicable to combustion turbines with a base load heat input rating greater than 250 MMBtu/hr and the capability of selling more than 25 MW-net of electricity to the grid. The emission limitation for new natural gas-fired base load combustion turbines is 1,000 pounds of CO_2 per MWh of gross energy output, and for non-base load natural gas-fired combustion turbines the limit is a fuel-based heat input standard of 120 pounds of CO_2 per mmBtu of heat input.

In setting the fuel-based standard for non-base load combustion turbines, the EPA concluded that the Best System of Emission Reduction (BSER) is the use of clean fuels (i.e., natural gas with an allowance for a small amount of distillate oil). In selecting this BSER, EPA made the following conclusions:

1. Carbon capture and sequestration (CCS) does not meet the BSER criteria because;

a. The low capacity factors and irregular operating patterns (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.

b. Because the CCS system would remain idle for much of the time while these units are not running, the cost-effectiveness of CCS for these units would be much higher than for base load units[13].

2. High-efficiency natural gas-fired combined cycle (NGCC) units designed for base load applications do not meet any of the BSER criteria for non-base load units because:

   a. Non-base load units need to be able to start and stop quickly, and NGCC units designed for base load applications require relatively long startup and shutdown periods. Therefore, conventional NGCC designs are not technically feasible for the non-base load subcategory.

   b. Non-base load units operate less than 10 percent of the time on average. As a result, conventional NGCC units designed for base load applications, which have relatively high capital costs, will not be cost-effective if operated as non-base load units.

   c. It is not clear that a conventional NGCC unit will lead to emission reductions if used for non-base load applications. As some commenters noted, conventional NGCC units have relatively high startup and shutdown emissions and poor part-load efficiency, so emissions may actually be higher compared with simple cycle technologies that have lower overall design efficiencies but better cycling efficiencies[14].

   d. Because the majority of non-base load combustion turbines operate less than 10 percent of the time, it would be cost-prohibitive to require fast-start NGCC, which have relatively high capital costs compared to simple cycle turbines, as the BSER for all non-base load applications.

3. High-efficiency simple cycle turbines are primarily used for peaking applications.

4. High-efficiency simple cycle turbines often employ aeroderivative designs because they are more efficient at a given size and are able to startup and ramp to full load more quickly than industrial frame designs.

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[13] 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 533 of 768.

[14] 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 533 and 534 of 768.

Under Subpart TTTT, a combustion turbine is classified as a non-base load unit if it supplies less than its *design efficiency* times its *potential electric output* as net electric sales on a 3-year rolling average. These terms are defined as:

> *Design efficiency* means the rated overall net efficiency (e.g., electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (e.g., CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17) or ISO 2314:2009 Gas turbines – acceptance tests (incorporated by reference, see §60.17).
>
> *Potential electric output* means 33 percent or the base load rating design efficiency at the maximum electric production rate (e.g., CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 310,000 MWh 12 month potential electric output capacity).
>
> *Base load rating* means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, base load rating includes the heat input from duct burners.

The proposed LMS100 GTs have an estimated design heat rate of 7,776 Btu/kWh (LHV) and a gross electric output of 116.2 MW. The baseload rating of each GT is 904 mmBtu/hr (LHV), or 1,002 mmBtu/hr (HHV) at ISO conditions (not at site conditions), and the estimated ISO design efficiency is 43.9%. Therefore, these units meet the applicability requirements for Subpart TTTT. The *potential electric output* for the LMS100 is estimated as:

$$Potential\ electric\ output = 43.9\% \times \left(\frac{904\ mmBtu}{hr}\right)\left(\frac{10^6\ Btu}{mmBtu}\right)\left(\frac{kWh}{3{,}413\ Btu}\right)\left(\frac{MWh}{1{,}000\ kWh}\right)\left(\frac{8{,}760\ hr}{yr}\right)$$

$$Potential\ electric\ output\ = 1{,}018{,}593\ MWh$$

Based on the above estimated values, to be classified as non-baseload units the electric output of each GT must be less than the *design efficiency* (43.9%) times its *potential electric output* (1,018,593 MWh), or approximately 447,162 MWh as net electric sales on a 3-year rolling average. APS is proposing to limit operations of the LMS100 GTs so they are classified as non-baseload gas-fired units. The net electric sales for each LMS100 GT will be limited to no more than the design efficiency times the potential electric output on a 3-year rolling average. The design efficiency and potential electric output will be determined during the initial performance test using the methods referenced in 40 CFR 60 Subpart TTTT.

Since these GTs will be classified as non-baseload gas-fired units, the relevant 40 CFR 60 Subpart TTTT performance standard is the fuel-based heat input standard of 120 pounds of CO_2 per mmBtu of heat input. Compliance with this emission limit can be demonstrated simply by combusting natural gas as the exclusive fuel.

TABLE B7-1. Potential greenhouse gas (GHG) emissions for each GE LMS100 gas turbine during normal operation.

Pollutant		Emission Factor	Heat Input Capacity	Total GHG Emission Factor		Potential to Emit, EACH TURBINE		Fuel Use Limit	Potential to Emit, G3 – G7
		lb/mmBtu	mmBtu/hr	CO_2e Factor[4]	lb/mmBtu	lb/hour	tons/yr	10^6 mmBtu/yr	tons/yr
Carbon Dioxide	CO_2	116.98	970	1	117.0	113,466.8	496,985	18.8	1,012,190
Methane	CH_4	0.002205	970	25	0.0551	53.5	234	18.8	477
Nitrous Oxide	N_2O	0.000220	970	298	0.0657	63.7	279	18.8	568
TOTAL GHG EMISSIONS, AS CO_2e					**117.1**	**113,584.0**	**497,498**		**1,013,235**

TABLE B7-2. Potential greenhouse gas (GHG) emissions for each GE LMS100 gas turbine during periods of startup and shutdown.

Pollutant		GHG Emission Factor	Startup		Shutdown		SU/SD Operation	Potential to Emit	Potential to Emit, G3 – G7
		lb/mmBtu	minutes	lb/event	minutes	lb/event	events/yr	ton/year	tons/yr
Carbon Dioxide	CO_2	116.98	30	42,813.2	11	5,030.0	730	17,463	87,314
Methane	CH_4	0.055	30	20.2	11	2.4	730	8	41
Nitrous Oxide	N_2O	0.066	30	24.0	11	2.8	730	10	49
TOTAL, AS CO_2e		**117.1**		**42,857.5**		**5,035.2**		**17,481**	**87,404**

TABLE B7-3. Total potential greenhouse gas (GHG) emissions for all five proposed GE Model LMS100 gas turbines.

Pollutant		Normal Operation	Startup / Shutdown	TOTAL
Carbon Dioxide	CO_2	1,012,190	87,314	1,099,504
Methane	CH_4	477	41	518
Nitrous Oxide	N_2O	568	49	618
TOTAL, AS CO_2e		972,252	1,013,235	**1,100,640**

Footnotes

1. Potential emissions for each turbine are based on 8,760 hours per year of operation. Potential emissions for all turbines combined are based on an operational limit of 18,800,000 mmBtu per year of natural gas heat input for all five turbines combined.

2. The emission factors for the greenhouse gases, including CO_2, N_2O and CH_4 are from 40 CFR Part 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

7.4 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.

Table B7-4 is a summary of CO_2 control technologies and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database and other recent permit decisions. Recent BACT emission limits have been expressed on both a pound per megawatt hour of electric output basis (both gross and net output), and also based on mass emission limits expressed in tons per year. The averaging periods for these emission limits are typically long term, 12-month limits. This long term averaging period is also consistent with the proposed standards of performance for CO_2 emissions under 40 CFR 60 Subpart KKKK. 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 energy efficient processes.

TABLE B7-4. Recent GHG BACT limits for natural gas-fired simple-cycle gas turbines.

Facility	State	Permit Date	Limit	Units	Averaging Period
Troutdale Energy Center, LLC	OR	Mar-14	1,707	lb CO_2/MWhr (g)	12-month
El Paso Electric Montana Power Station	TX	Mar-14	1,100	lb CO_2/MWhr (g)	5,000 op. hours
EFS Shady Hills LLC	FL	Jan-14	1,377	lb CO_2/MWhr (g)	12-month
Basin Electric Power Coop. Lonesome Creek Gen. Sta.	ND	Sep-13	220,122	ton/year	12-month
Basin Electric Power Coop. Pioneer Generating Station	ND	May-13	243,147	ton/year	12-month
Montana-Dakota Utilities R.M. Heskett Station	ND	Feb-13	413,198	ton/year	12-month
Cheyenne Light, Fuel & Power	WY	Sep-12	1,600	lb CO_2e/MWhr (g)	365 day
Pio Pico Energy Center	CA	Nov-12	1,328	lb CO_2/MWhr (g)	720 op. hours
York Plant Holding, LLC Springettsbury	PA	2012	1,330	lb CO_2e/MWhr (n)	30-day
LADWP Scattergood Generating Station	CA	2013	1,260	lb CO_2e/MWhr (n)	12-month

Footnotes

1. Emission limits expressed on lb CO_2/MWhr (g) means gross electric output; limits based on lb CO_2/MWhr (n) means net electric output.

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 gas turbine, and is therefore unavoidable. There are four potential control options for reducing CO_2 emissions from these gas turbines:

1. **The use of low carbon containing or lower emitting primary fuels,**
2. **The use of energy efficient processes and technologies, including,**
   a. Efficient simple cycle gas turbine generators,
   b. Combined cycle gas turbines,
   c. Reciprocating internal combustion engine generators,
3. **Good combustion, operating, and maintenance practices,**
4. **Carbon capture and sequestration (CCS) as a post combustion control system.**

As will be demonstrated in the Step 1 analysis, the use of combined cycle GTs would change the project in such a fundamental way that the requirement to use these technologies would effectively redefine 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.
>
> 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.

7.4.1 Alternative combustion technologies for the combustion turbines.

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

7.4.1.1 Steam Injection.

The combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs. Therefore, steam injection is not an available control option for the LMS 100 GTs and is therefore eliminated as a control technology option[15].

7.4.1.2 Dry Low NO_x Combustion.

Dry Low NO_x (DLN) combustion is available for the LMS100 GTs and under certain operating conditions can achieve the same NOx emission rate as water injection, equal to a GT exhaust prior to the SCR systems of 25 ppmdv at 15% O_2. However, while water injected LMS100 GTs can achieve the NO_x emission rate of 25 ppm continuously down to 25% of load, the DLN equipped units cannot achieve this NO_x emission rate at loads below 50% of load. Furthermore, the DLN equipped GTs produce much more carbon monoxide (CO) and other products of incomplete combustion than the water injected GTs. As a result, the DLN equipped GTs can only meet the CO BACT emission limit down to 75% load, while the water injected GTs can also achieve the CO BACT limit continuously down to 25% of load. Because a GT turndown to 25% 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 dismissed under Step 1 as redefining the source. In addition, the significant lack of turndown capability for the DLN equipped GTs makes the DLN equipped LMS100 GTs technically infeasible for these peaking units. Therefore, even if DLN were retained in Step 1, DLN would be dismissed under Step 2 as technically infeasible.

DLN equipped LMS100 GTs also have a lower peak electric generating capacity than the water injected units. The peak electric output at 105 ^oF is reduced significantly; from 109.9 MW (gross) for the water injected GTs to only 97.2 MW for the DLN equipped GTs. This is a significant reduction in peak generating and ramping capacity which directly affects the ability of the project to meet its basic design requirements, another reason for dismissal under Step 1 of BACT.

7.4.1.3 Water Injection.

Good combustion practices including the use of water injection is an effective method for controlling CO and VOC emissions from these gas turbines. Water injection is the most widely used combustion control technology for aero derivative gas turbines and gas turbines 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. Injection rates for both water and steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (e.g., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

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[15] The GE paper *New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™* which is available at GE's website at http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf is a 2004 paper does indicate steam injection as a potential option. However, this paper preceded the first commercial operating date for an LMS 100 CTG in June 2006. The steam injected units are not available. In an e-mail from Phil Tinne, GE Power & Water, to Scott E McLellan, Arizona Public Service dated May 14, 2015, Mr. Tinne states "I confirm that we have not developed steam injection for the LMS100, either for NOx control or power supplementation, thus it is not on our option list."

A significant advantage of water injection for these simple cycle gas turbines 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 turbines. This is especially important for these gas turbines because the Ocotillo Power Plant is located in a region with high ambient temperatures.

Since 2013, three peaking power plants consisting of 19 water-injected LMS 100 simple cycle GTs have commenced commercial operation in California. These plants include the Walnut Creek Energy Park (City of Industry, 5 units), the CPV Sentinel Energy Project (Riverside County, 8 units), and the Haynes Generating Station Repowering Project (6 units). Water injection was concluded to represent BACT for all of these GTs. In 2013, a water-injected LMS100 GT also commenced commercial operation at El Paso Electric Company's Rio Grande Power Plant in Sunland Park, New Mexico (this unit does not appear to be subject to PSD review). In addition, the Pio Pico Energy Center (San Diego County) received a PSD construction permit for 3 water-injected LMS 100 simple cycle GTs in 2013. The water-injected LMS 100 GTs have been selected as BACT for these peaking power plants because of their very high efficiency when operating in simple cycle mode, their fast start times, high turndown rates, flexible operation, and high peak electric output, especially under high ambient temperature conditions. Therefore, the water-injected LMS 100 GT is an available control option that is demonstrated, available and technically feasible for these proposed peaking duty GTs.

7.4.2 Reciprocating internal combustion engine generators.

If the largest available RICE engines were used for this project, this power plant would need to construct and operate at least twenty eight (28) RICE engines. This would be a more complex power plant to construct and operate, and this many generating units may not actually fit on the plant site. This control technology is further analyzed in Step 2 of the BACT analysis.

7.4.3 Combined cycle gas turbines.

The use of combined cycle gas turbines would change the project in such a fundamental way that the plant could not meet its stated purpose of a peaking power plant. 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.

The Ocotillo Modernization Project is being proposed to provide quick start and power escalation capability over the range of 25 MW to 500 MW 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 combustion turbines as peaking units, while combined cycle combustion turbines are installed to provide baseload capacity. The proposed LMS 100 GTs can provide an electric power ramp rate equal to 50 MW per minute per GT which is critical for the project to meet its purpose. When all 5 proposed GTs are operating at 25% load, the entire project can provide more than 375 MW of capacity in less than 2 minutes. Combined cycle units cannot provide this very fast response time over a range of 25 MW to 500 MW, which is a design requirement of this Project.

Combined cycle units are 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 units is incompatible with the purpose of the Project which is to provide quick response to changes in the supply and demand of electricity in which these turbines may be required to startup and shutdown multiple times per day. Therefore, the use of combined cycle GTs is 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 units 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 GTs have other technical problems which also make them infeasible for this Project. When a combined cycle GT is started from a full stop as is typical for a peaking unit, the GT is simply operating in the simple cycle mode. The large frame GTs typically used in combined cycle applications do not have the high turndown ratio that can be achieved with aero-derivative GTs like the LMS 100. Large frame GTs also have longer startup times. And because the LMS 100 GTs have an intercooler which is not used in large frame GTs, the large frame GTs are not as efficient when operated in simple cycle mode. Therefore, constructing a combined cycle unit and then operating the combined cycle unit as a peaking unit would mean that the combined cycle unit 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 GTs.

Even a fast-start combined cycle GT is only capable of achieving startup within 30 minutes if the unit is already hot. If the unit is not hot, the combined cycle GT may require up to 3½ hours to achieve full load under some conditions. These longer startup times are incompatible with the purpose of the proposed project to provide a rapid 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 of the GT, 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 GTs are rejected in Step 1 because, as EPA stated in the EFS Shady Hills Project, combined cycle GTs would not meet the basic purpose and need of the Ocotillo Modernization Project and would therefore constitute a redefinition of the source. Nevertheless, combined cycle GTs have also been analyzed in Step 2 of the BACT analysis.

7.4.4 Energy Storage Options.

Several types of energy storage technologies are available including batteries, compressed air energy storage (CAES), liquid air energy storage (LAES), pumped hydro, and flywheels. However, incorporating energy storage into the project is not an available BACT control option because these options would fundamentally redefine the source. In EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[16] 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."

Like the Ocotillo Modernization Project, the purpose of the Red Gate project was 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 combustion turbines (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. [17]

Even if there were some off-site generation source charging energy storage on the Ocotillo site, and even if it were appropriate to consider energy storage options in Step 1 of the BACT analysis, as explained further below, we are not aware of any available energy storage option that could supply a maximum power output of 500 MW for a potentially extended period of time, which is what this project requires.

[16] *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 .

[17] 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.

7.4.4.1 Battery Storage.

The largest grid-connected battery storage systems that we are aware of include the 32 MW lithium-ion battery-based Laurel Mountain Wind Farm (W. Virginia) and the 36 MW lead-acid battery-based Notrees Battery Facility (Texas). The Laurel Mountain facility has 8.0 MWh of energy storage (and output); the Notree facility has 9.0 MWh of energy storage. The Ocotillo Project will be designed for a maximum energy output of more than 500 MWh, potentially for extended periods of time. The required electric energy output of the Ocotillo Project is therefore more than 50 times larger than the largest battery storage facilities currently in service. We are not aware of any demonstrated battery storage facilities that can provide the required maximum power capacity of 500 MW for multiple Therefore, the battery storage option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project – to provide between 25 MW to 500 MW of electrical energy as needed[18] 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.

7.4.4.2 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. However, we are not aware of any commercially operating LAES facilities on the electric power output scale of the proposed Ocotillo Power Plant. Therefore, like batteries, the LAES 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 25to 500 MW of electricity as needed.

It is important to note that <u>energy storage technologies are not “zero emissions” technologies</u>. The “round trip” energy efficiency of LAES is expected to be 50 – 60%[19]. Therefore, while this technology may have near zero emissions at the site, the technology simply stores energy produced elsewhere. If that energy were produced for example at a natural gas-fired combined cycle facility with a GHG emission rate of 1,000 lb CO_2/MWh, the net emission rate after the LAES storage would be 1,670 to 2,000 lb CO_2/MWh.

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[18] 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.”

[19] 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.

7.4.4.3 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. Temporal Power, in collaboration with the Ministry of Energy and NRStor developed the first grid-connected flywheel energy storage facility in Ontario, Canada. This is a 2 MW system primarily designed for short term energy balancing on the power grid. We are not aware of larger FES systems installed to date. 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.

7.4.4.4 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. 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 Ocotillo 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.

7.4.4.5 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 Ocotillo Power Plant, and water resources in the Phoenix area are scarce. Therefore, this technology is not an “available control option” at the Ocotillo Power Plant and may be eliminated as a BACT option in Step 1 of the BACT analysis.

7.5 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 gas turbines include the use of low carbon containing fuels, energy efficient processes and technologies including efficient simple cycle gas turbines, combined cycle gas turbines, reciprocating internal combustion engines, and the use of post combustion control systems, including carbon capture and sequestration (CCS).

7.5.1 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 B7-5 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 GTs. Because natural gas is the lowest CO_2 emitting fossil fuel available for this Project, further evaluation of clean fuels is not necessary.

TABLE B7-5. 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.

7.5.2 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.

7.5.2.1 High Efficiency Simple Cycle Gas turbines.

APS is proposing to install five natural gas-fired LMS100 simple cycle GTs for this Project. The LMS100 GTs are among the most efficient, and therefore the lowest CO_2 emitting, simple cycle gas turbines which are commercially available at this time. The LMS100 simple cycle gas turbine generators utilize an aero derivative gas turbine coupled to an electric generator to produce electric energy. A gas turbine 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 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 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.

To improve efficiency, the LMS100 uses an innovative intercooling system which takes the intermediate pressure air out of the turbine, cools it to an optimum temperature in an external water-cooled heat exchanger (the intercooler), and then redelivers this air to the high-pressure compressor. The near constant stream of low temperature air to the high pressure compressor reduces the work of compression, resulting in a higher pressure ratio (42:1), increased mass flow, and increased power output. This reduced work of compression also improves the overall gas turbine thermal efficiency. The use of the intercooler combined with higher combustor firing temperatures allows the LMS100 to achieve a simple cycle thermal efficiency of approximately 44% at 100% load operation. The result is that the LMS100 GTs are among the most efficient, and therefore the lowest CO_2 emitting simple cycle gas turbines which are commercially available at this time.

7.5.2.2 Reciprocating Internal Combustion Engines.

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

7.5.2.3 Combined-Cycle Gas turbines.

Combined cycle gas turbines are highly efficient power plants. However, the purpose of this Project is to construct peaking power capacity. The Ocotillo Modernization Project is being proposed to provide quick start and power escalation capability over the range of 25 MW to 500 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 escalation capacity.

These requirements for the purpose and need for this peaking capacity make combined-cycle gas turbines technically infeasible for this Project because combined cycle GTs cannot meet the rapid startup and shutdown requirements for this peak power capacity. The start-up of a combined-cycle GT 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 GT 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 GT is normally much longer than that of a similarly-sized simple cycle GT. 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.

Combined cycle units are unable to respond rapidly to the large swings in generation which can be caused by a sudden drop in generation from renewable energy sources. For example, the Huntington Beach Energy Plant (HBEP) “peaking project” is an example of a fast-start combined cycle plant that can provide peak power. The HBEP is a 939 MW power plant, which is almost twice the size of the proposed Project. HBEP will consist of two power blocks each with a three-on-one configuration, i.e., each power block will have three Mitsubishi turbines, three heat recovery steam generators, and one steam turbine. The HBEP has a maximum ramp rate of 110 MW/minute, or 220 MW for the entire project. This can be compared to the five LMS100s proposed for Ocotillo; when all 5 GTs are operating at 25% load, the project can provide approximately 375 MW of ramping capacity in less than 2 minutes. Therefore, the ramp rate capacity of a fast-start combined cycle project such as the HBEP would not meet the Project needs.

In summary, the long startup time and reduced ramp rate capacity for combined cycle units is incompatible with the purpose of the Project. Therefore, the use of combined cycle GTs 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.

7.5.3 Good Combustion, Operating, and Maintenance Practices.

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

7.5.4 Carbon Capture and Sequestration (CCS).

There are three approaches for Carbon Capture and Sequestration (CCS), including pre-combustion capture, post-combustion capture, and oxyfuel combustion[20]. 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 which does not require gas conversion. Oxyfuel combustion is not commercially available for gas turbine applications.

Post-combustion CCS is theoretically applicable for gas turbine power plants. However, in contrast to readily-available high-efficiency simple cycle GT technologies, emerging CCS technologies are not currently commercially available for simple cycle GT projects. There are no current CCS systems currently operating on full-scale power plants in the United States. 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 combustion turbines. 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.[21] Further, in setting the fuel-based standard for non-base load combustion turbines, the EPA concluded that the low capacity factors and irregular operating patterns (e.g., 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.

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 gas. Before CO_2 emitted from these gas turbines can be sequestered, it must be captured as a relatively pure gas. CO_2 may be captured from the gas turbine 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 GT flue gas due to the characteristics of the exhaust stream. The low concentration of CO_2 in natural gas-fired gas turbine applications adds to the challenge of CO_2 capture over coal-fired power plants. The gas turbines proposed for this Project are expected to contain approximately 5 to 6% CO_2 concentration 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 gas turbines used for peaking load operation, because of the highly variable exhaust gas flow and low CO_2 concentration. These challenges and additional

[20] Intergovernmental Panel on Climate Change (IPCC), 2005.

[21] 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.

equipment would have significant impacts on the operation of these turbines and the ability of these turbines to meet the basic project design requirements to provide peak power capacity. These challenges would also significantly affect the power output, efficiency, and cost of this Project.

Post-combustion carbon capture has been demonstrated on a gas turbine exhaust with a low CO_2 concentration in the exhaust stream at Florida Power and Light's natural gas power plant in Bellingham, MA. 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 gas turbine power plants.

One of the most significant power applications of this CO_2 removal system is at Florida Power & Light's licensed plant at the Bellingham Energy Center in Bellingham, MA. This plant captures about 365 short tons per day of CO_2 from the exhaust of a natural gas-fired turbine. However, each of the proposed GTs could produce about 6,570 tons of CO_2 per day, or almost 20 times more than the CO_2 capture system at the Bellingham Energy Center. While this technology is available, it has not yet been deployed at a scale that could serve these GTs.

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 gas turbines 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 GT 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 gas turbines due to the high exhaust gas temperature of 480 - 500 ^oC (900 – 930 ^oF). Note that the LMS100 GTs have exhaust gas temperatures of 750 to 840 ^oF. Therefore, to be able to actually capture CO_2 emissions, the exhaust gas would need to be reduced by 630 to 720 ^oF. 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 GTs. Because combined-cycle GTs are not technically feasible for this Project, CCS is also not technically feasible for this Project.

7.5.5 Conclusions regarding technically feasibility control options.

Table B7-6 is a summary of the technically feasible control technologies for the control of GHG emissions from the proposed gas turbines based on the above analysis.

TABLE B7-6. Summary of the technically feasible GHG control technologies for the turbines.

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 gas turbines	Feasible
b. Combined cycle gas turbines	Infeasible
c. Reciprocating internal combustion engines	Feasible
3. Good combustion and operating practices,	Feasible
4. Carbon capture and sequestration (CCS).	Infeasible

7.6 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 peak electric generating capacity:

1. The use of low carbon containing or lower emitting primary fuels,
2. Efficient simple cycle gas turbine generators,
3. Good combustion and operating practices,
4. Reciprocating internal combustion engine (RICE) generators.

With respect to the use of lower emitting primary fuels, both GT and RICE generators 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.

Table B7-7 includes detailed performance data for the proposed GE LMS100 GTs. The lowest *guaranteed* design heat rate (i.e., the highest efficiency) for these turbines at 100% load and an ambient temperature of 20 ^{o}F (an unusual operating temperature for these GTs) is 8,711 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 8,711 Btu/kWh$_g$ is equal to an electric efficiency of 39.2% and 1,018 lb CO_2/MWh$_g$. The estimated actual performance from Table B5-7 at this ambient temperature and site elevation is 8,667 Btu/kWh$_g$, equal to 39.4% and 1,021 lb CO_2/MWh$_g$ (this is the predicted initial performance before GT performance degradation due to normal operation).

Please note that these efficiency values are based on the *higher heating value* (HHV) of natural gas. The turbine manufacturer's quoted efficiency of approximately 43% at 100% load is based on the *lower heating value* of the fuel, and is also based on the gross output of the turbine without SCR and oxidation catalyst air quality control systems. From Table B5-7, the HHV is 1.109 times the LHV, or approximately 10% higher.

Some natural gas-fired lean burn RICE engines have design heat rates as low as approximately 7,500 Btu/kWh$_g$ again based on the LHV of natural gas, or approximately 8,250 Btu/kWhg based on the HHV. This heat rate is equal to an efficiency of approximately 45.5% (LHV), or 41.4% (HHV). This RICE generator efficiency is equal to a CO_2 emission rate of 964 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 50SG. It is also important to note that this engine does require a small amount of fuel oil to be combusted even when firing on natural gas. The above CO_2 emission rate is based on 100% natural gas combustion. Other manufacturers such as Caterpillar make natural gas engines of up to approximately 10 MW in size. Therefore, to achieve the same gross electric output, the Project would require from 28 to 50 RICE generators. The existing Ocotillo Generating Station may not have sufficient space for this many RICE generators.

Table B7-8 is a ranking of the technically feasible GHG control technologies based on the above stated efficiencies, heat rates, and CO_2 emission rates for the RICE generators and the GTs.

TABLE B7-8. Ranking of the technically feasible GHG control technologies for the turbines.

Technology	Minimum Heat Rate Btu/kWh$_g$	Actual CO_2 Emission Rate at the Stated Heat Rate lb/MWh$_g$
Natural Gas-Fired RICE Engines	8,250	964
Natural Gas-Fired GE LMS100 Gas Turbines	8,667	1,013

TABLE B7-7. Performance data for the General Electric Model LMS100 simple cycle gas turbines at various load and ambient air conditions.

Case #	100	105	110	115	116	121	126	131	228	233	238	243	180	185	190	195	196	201	206	211	212	217	222	227	MAX
Dry Bulb Temperature, °F	20	20	20	20	41	41	41	41	73	73	73	73	105	105	105	105	113	113	113	113	120	120	120	120	120
Wet Bulb Temperature, °F	17	17	17	17	34	34	34	34	57	57	57	57	71	71	71	71	75	75	75	75	78	78	78	78	78
Relative Humidity, %	60	60	60	60	51	51	51	51	37	37	37	37	19	19	19	19	17	17	17	17	15	15	15	15	60
Engine Inlet																									
Conditioning	HEAT	HEAT	HEAT	HEAT	NONE	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	
Tons Chill or kBtu/hr Heat	4,203	3,753	3,428	2,868					1,063				2,598				2,605				2,609				4,203
Partial Load, %	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	
Gross Generation, MW	111.3	83.5	55.7	27.8	111.0	83.3	55.5	27.8	109.8	82.3	54.9	27.4	109.9	82.4	54.9	27.5	108.1	81.1	54.0	27.0	106.8	80.1	53.4	26.7	111.3
Gross Generation, kW	111,334	83,505	55,668	27,835	111,000	83,253	55,505	27,752	109,790	82,341	54,892	27,448	109,856	82,392	54,925	27,465	108,071	81,055	54,033	27,018	106,817	80,110	53,403	26,702	111,334
Est. Btu/kW-hr, LHV	7,815	8,215	9,305	12,053	7,831	8,241	9,327	12,089	7,843	8,309	9,389	12,183	7,847	8,387	9,418	12,216	7,878	8,436	9,476	12,303	7,901	8,475	9,520	12,366	12,366
Guar. Btu/kW-hr, LHV	7,854	--	--	--	7,870	--	--	--	7,883	--	--	--	7,886	--	--	--	7,918	--	--	--	7,941	--	--	--	7,941
Est. Btu/kW-hr, HHV	8,667	9,111	10,320	13,367	8,684	9,140	10,344	13,407	8,698	9,215	10,413	13,511	8,702	9,301	10,445	13,547	8,737	9,356	10,509	13,644	8,763	9,398	10,558	13,714	13,714
Guar. Btu/kW-hr, HHV	8,711				8,728				8,742				8,746				8,781				8,807				8,807
Fuel and Water Flow																									
MMBtu/hr, LHV	870	686	518	336	869	686	518	336	861	684	515	334	862	691	517	336	851	684	512	332	844	679	508	330	870
MMBtu/hr, HHV	**965**	**761**	**574**	**372**	**964**	**761**	**574**	**372**	**955**	**759**	**572**	**371**	**956**	**766**	**574**	**372**	**944**	**758**	**568**	**369**	**936**	**753**	**564**	**366**	**965**
Fuel (Nat Gas) Flow, lb/hr	42,250	33,312	25,152	16,291	42,209	33,320	25,139	16,292	41,814	33,225	25,028	16,237	41,859	33,553	25,122	16,291	41,346	33,203	24,864	16,141	40,985	32,966	24,690	16,035	**42,250**
Water Flow, lb/hr	27,619	18,990	12,516	6,383	27,568	19,012	12,496	6,371	25,627	17,902	11,670	5,782	25,401	17,433	11,074	5,315	24,415	16,950	10,621	5,014	23,795	16,731	10,379	4,852	**27,619**
																									0
Exhaust Parameters																									**0**
Temperature, °F	771	750	794	854	784	766	807	868	787	782	817	878	786	806	824	883	790	811	828	886	793	817	833	890	**890**
Temperature, °R	311	291	334	394	324	306	347	409	327	322	357	418	327	346	364	423	330	352	368	426	334	358	373	431	**431**
Exhaust Flow, lb/hr	1,815,959	1,578,099	1,260,994	893,661	1,796,111	1,556,233	1,244,993	882,351	1,779,526	1,525,792	1,227,049	870,908	1,780,587	1,498,024	1,219,368	866,800	1,759,546	1,478,851	1,205,746	858,761	1,743,421	1,463,464	1,194,151	851,480	1,815,959
Exhaust Molecular Weight	16.087	15.952	15.877	15.767	16.107	15.976	15.898	15.787	16.117	16.010	15.923	15.812	16.118	16.056	15.945	15.830	16.122	16.062	15.950	15.834	16.126	16.067	15.956	15.839	16.126
Exhaust Flowrate, ACFM	446,520	365,183	336,861	283,659	458,654	378,508	345,576	290,143	458,630	390,276	349,643	292,588	458,178	409,808	353,494	294,419	457,360	411,213	353,467	293,610	457,995	413,843	354,881	293,967	**458,654**
Estimated Stack Emissions with Exhaust System in GE Scope of Supply and the Notes Below																									
NO_x ppmvd Ref 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	**2.5**
NO_x, lb/hr	9.3	7.3	5.5	3.6	9.3	7.3	5.5	3.6	9.2	7.3	5.5	3.6	9.2	7.4	5.5	3.6	9.1	7.3	5.5	3.5	9.0	7.2	5.4	3.5	**9.3**
NH_3 Slip, ppmdv, 15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	**5.0**
NH_3 Slip, lb/hr	6.9	5.4	4.1	2.6	6.9	5.4	4.1	2.6	6.8	5.4	4.1	2.6	6.8	5.4	4.1	2.6	6.7	5.4	4.0	2.6	6.7	5.4	4.0	2.6	**6.9**
CO ppmvd Ref 15% O2	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	**6.0**
CO, lb/hr	13.5	10.7	8.1	5.2	13.5	10.7	8.1	5.2	13.4	10.6	8.0	5.2	13.4	10.7	8.0	5.2	13.2	10.6	8.0	5.2	13.1	10.6	7.9	5.1	**13.5**
VOC ppmdv, 15% O2, as C	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	**2.0**
VOC, lb/hr (MW = 14.36)	2.6	2.0	1.5	1.0	2.6	2.0	1.5	1.0	2.6	2.0	1.5	1.0	2.6	2.1	1.5	1.0	2.5	2.0	1.5	1.0	2.5	2.0	1.5	1.0	**2.6**
PM_{10}, lbs/hr	5.4				5.4				5.4				5.4				5.4				5.4				**5.4**
CO_2, weight %, wet basis	6.2572	5.6816	5.3711	4.9124	6.3196	5.7619	5.4365	4.9747	6.3187	5.8590	5.4908	5.0225	6.3217	6.0251	5.5456	5.0625	6.3188	6.0394	5.5505	5.0627	6.3215	6.0593	5.5650	5.0724	6.3217
CO_2, lb/hr	113,628	89,661	67,729	43,900	113,507	89,669	67,684	43,894	112,443	89,396	67,375	43,741	112,563	90,257	67,621	43,882	111,182	89,314	66,925	43,476	110,210	88,676	66,455	43,190	113,628
CO_2, lb/mmBtu	117.8	117.9	117.9	118.0	117.8	117.8	117.9	118.0	117.7	117.8	117.9	117.9	117.7	117.8	117.9	117.9	117.8	117.8	117.9	117.9	117.7	117.8	117.9	117.9	118.0
CO_2, lb/MWhr (gross)	1,021	1,074	1,217	1,577	1,023	1,077	1,219	1,582	1,024	1,086	1,227	1,594	1,025	1,095	1,231	1,598	1,029	1,102	1,239	1,609	1,032	1,107	1,244	1,617	1,617
CO_2, lb/MWhr (gross, deg)	1,082	1,138	1,290	1,672	1,084	1,142	1,293	1,677	1,086	1,151	1,301	1,689	1,086	1,161	1,305	1,694	1,091	1,168	1,313	1,706	1,094	1,173	1,319	1,715	1,715

Footnotes

1. Performance data is from General Electric, Engine LMS-100PA, generator BDAX 82-445ERH Tewac 60Hz, 13.8kV, 0.85PF (EffCurve#: 32398; CapCurve#: 34089). Data run conducted on 5/28/2014.
2. All data for elevation of 1,178 ft and pressure of 14.081 (0.95815 atm).
3. Performance and emissions data are based on the following natural gas fuel values: Btu/lb, LHV 20,593 Btu/lb, HHV 22,838 Ratio, HHV to LHV 1.109
4. CO_2 emissions are calculated from GE performance data and were not provided by GE. Emission rates expressed as "deg" are based on a 6% degradation in engine efficiency due to normal operation of the engine.

7.7 STEP 4. Evaluate the Most Effective Controls.

7.7.1 Natural Gas-Fired RICE Engines.

From Table B7-6, the use of RICE engines would have the lowest potential CO_2 emission rate of the technically feasible control options. At the CO_2 emission rates in Table B6-8, the use of these RICE engines may reduce CO_2 emissions by approximately 5% during normal operation, or, based on the proposed limits in this application, by approximately 55,000 tons per year. Note that this is an estimate of the potential reduction in CO_2 emissions. The use of from 28 to 50 RICE engines rather than 5 gas turbine generators 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 small reduction in CO_2 emissions, the use of RICE engines would result in a substantial increase in other regulated PSD pollutants, especially NO_x and PM_{10} emissions. 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 18V50DF16.3 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, or more than twice the emission concentration for the proposed gas turbines. The use of these engines would increase total potential NO_x emissions for the Project during normal operation by 50 – 100% as compared to the proposed GE LMS100 GTs.

In addition, the permit for these engines at the Humboldt Bay Power Plant also limits PM_{10} emissions to 3.6 lb/hr for each engine. Since each engine is rated at 16.3 MWe, the total RICE generator emissions for an equivalent of 100 MW electric output would be approximately 22 lb/hr, or more than 5 times the proposed limit for each of the LMS100 gas turbines. Thus, the use of these engines would increase total potential PM_{10} and $PM_{2.5}$ emissions for the Project by approximately 142 tons per year, from approximately 58 tons per year, to more than 200 tons per year.

The Ocotillo Power Plant is located in the City of Tempe, Maricopa County, Arizona. The location of the power plant is currently designated nonattainment for particulate matter less than 10 microns (PM_{10}) (classification of serious) and the 1997 and 2008 8-hour ozone standards (classification of marginal). Based on the ozone and PM_{10} nonattainment status of the area, it is appropriate to favor the technology that reduces NO_x and PM_{10} emissions over relatively small and potentially uncertain reductions in GHG emissions, especially when the difference in both NO_x and PM_{10} emissions between the two technologies is so great. 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 adverse collateral environmental impacts.

In summary, the adverse collateral environmental impacts from the use of RICE generators eliminates this option from further consideration. After the elimination of RICE generators from this GHG control technology review, high efficiency simple-cycle gas turbines represent the top control option.

7.7.2 Carbon Capture and Sequestration.

As stated above in Step 2, CCS is not a technically feasible control option for these simple cycle GTs. However, even if the severe technical feasibility issues could be resolved, CCS is not an economically feasible control technology for these GTs. 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 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) (this document is available at http://www.epa.gov/region9/air/permit/palmdale/palmdale-response-comments-10-2011.pdf). The Palmdale Hybrid Power Project is 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. 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.

The Palmdale Hybrid Power Project is similar in size to the Ocotillo Modernization Project, and as was the case for Palmdale, the Ocotillo Project site does not have any nearby carbon sequestration sites available. Therefore, the approximate CCS costs and capital costs for both projects would be similar, and the costs for CCS would again be more than twice the facility's annual capital costs. Therefore, even if the severe technical feasibility issues for the application of CCS to the simple cycle GTs could somehow be resolved, the use of CCS for the Ocotillo Modernization Project is not an economically feasible control technology option for the simple cycle GTs.

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

7.8 STEP 5. Proposed Greenhouse Gas BACT Determination.

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

7.8.1 Gas Turbine Design Limit.

With respect to the turbine design, the proposed LMS100 GTs are among the most efficient, and therefore the lowest CO_2 emitting simple cycle gas turbines which are commercially available at this time. To achieve this high efficiency design requirement, these gas turbines will be designed to achieve an initial heat rate of at least 8,742 Btu per kilowatt hour of gross electric output based on the HHV of natural gas, at a dry bulb temperature of 73 ^oF. This heat rate is based on full load operation with inlet chilling.

7.8.2 Gas Turbine Operating Limit.

7.8.2.1 Operating Limit Based on the Worse-Case Operation.

The BACT emission limit must be achievable at all times and across all load ranges for which these turbines 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. To provide this capability, the gas turbines will be designed to meet the applicable BACT emission limits for CO, NO_x, PM, PM_{10}, $PM_{2.5}$, SO_2, and VOC emissions at steady state loads as low as 25% of the maximum output capability of the turbines, i.e., 25% load. In fact, based on discussions with the manufacturer, these GTs can be operated as low as 17% loads, but below 25% load the BACT emissions limits for CO, NO_x, PM, PM_{10}, $PM_{2.5}$, SO_2, and VOC emissions would need to be adjusted to be higher.

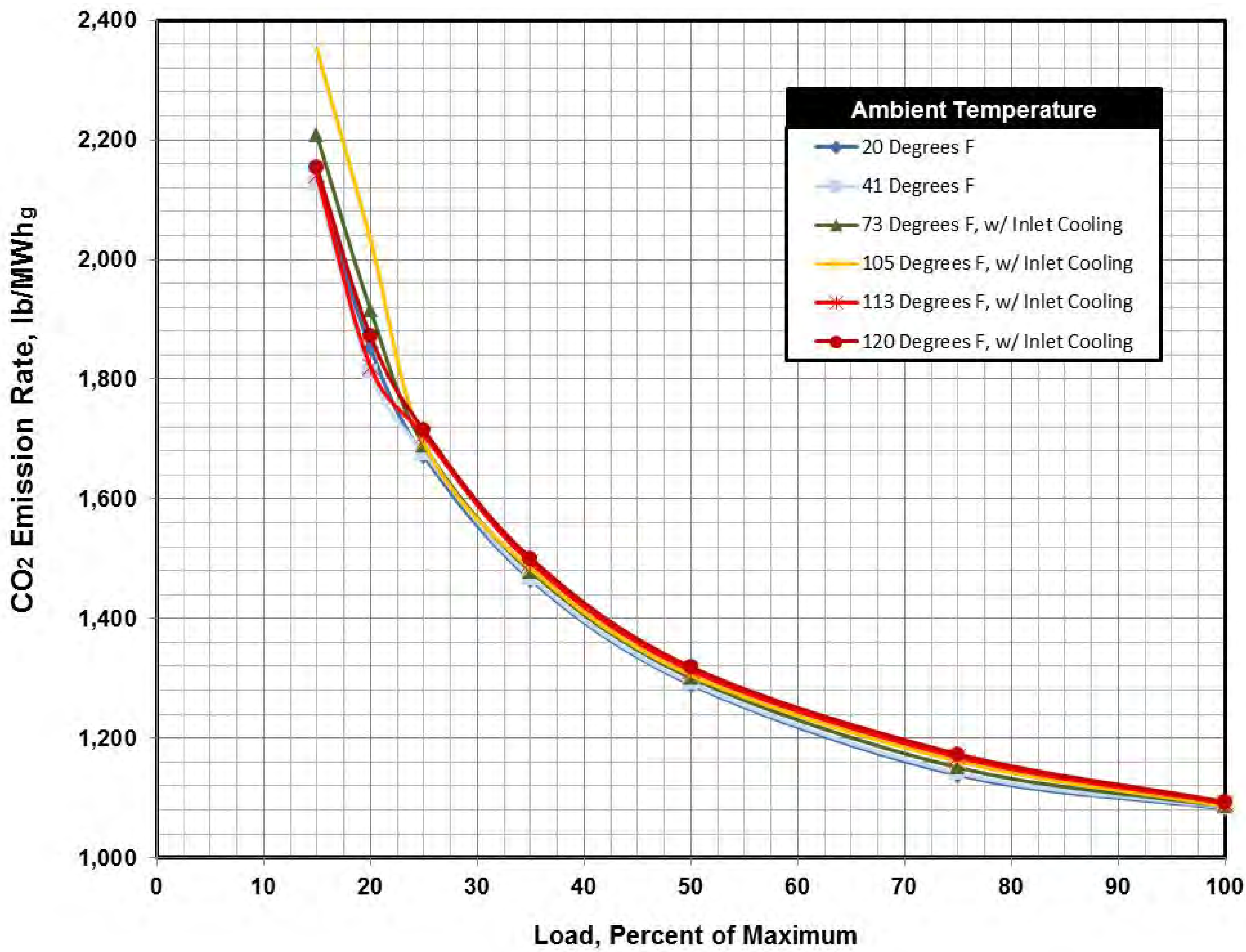
Turbine efficiency decreases and the CO_2 emission rate increases as the turbine load is decreased. In addition, the CO_2 emission rate may vary between gas turbines due to normal variation in the manufacturing process, and even with proper operation and maintenance, the CO_2 emission rate may increase over time due to the normal operation and wear of the GT components. Variation in turbines is expected to about 3%, and degradation in performance due to normal wear is expected to be an additional 3%, which can result in a 6% increase above the design values in Table B6-7.

Table B7-9 is a summary of the expected GT CO_2 emission rate, expressed in pounds of CO_2 per megawatt hour of gross electric output (lb CO_2/MWhg), based on the HHV of natural gas, at five ambient air conditions and across a range of operating loads. The values in Table B7-9 include a 6% increase above the design values. Figure B7-1 shows the relationship of the GT CO_2 emission rate as a function of load at 5 different ambient air temperature conditions. The average annual temperature for Phoenix is approximately 72 ^oF. From Table B7-9, at 73 ^oF, the CO_2 emission rate increases from 1,086 lb/MWh_g at 100% load, to 1,689 lb/MWh_g at 25% load. The average emission rate at 25% load for all ambient air conditions is 1,690 lb/MWh_g.

TABLE B7-9. Expected CO_2 emission rates for the GE LMS100 GTs at the Ocotillo Power Plant.

Ambient Dry Bulb Temperature	GT Load, % of Maximum Output						
	100%	75%	50%	35%	25%	20%	15%
20 °F	1,082	1,138	1,290	1,465	1,672	1,852	2,130
41 °F	1,084	1,142	1,293	1,468	1,677	1,811	2,128
73 °F, w/ Inlet Cooling	1,086	1,151	1,301	1,479	1,689	1,916	2,207
105 °F, w/ Inlet Cooling	1,086	1,161	1,305	1,483	1,694	2,033	2,350
113 °F, w/ Inlet Cooling	1,091	1,168	1,313	1,493	1,706	1,821	2,140
120 °F, w/ Inlet Cooling	1,094	1,173	1,319	1,501	1,715	1,872	2,153
Average	**1,090**	**1,160**	**1,300**	**1,480**	**1,690**	**1,880**	**2,180**

FIGURE B7-1. Relationship of the GT CO_2 emission rate as a function of load.



EPA Region 9 has 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. Note that the simple-cycle GTs proposed for the Pio Pico Energy Center are the same units being proposed by APS for this Project. 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 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.

7.8.2.2 Operating Limit Based on the Expected Operation.

APS has projected the expected operation of these proposed GTs in the first year of operation (2019) and also in 2023. Using a real-time simulation modeling program (Real Time Simulation), APS projected the expected number of startup and shutdown events per year, and also the expected gross electric generation and load profile. The projected resulting total CO_2 emissions from this analysis for all periods of operation are summarized in Table B7-10. The annual average CO_2 emission rate for the GTs based on the expected operation in 2019 and 2023 and including ALL periods of operation are estimated at 1,460 and 1,450 lb/MWh, respectively. The basis for these emission rates include the following:

1. The CO_2 emission rate at each load level are from Table B7-9. These emission rates are 6% above the design values as described above.
2. The CO_2 emissions for all startup and shutdown (SU/SD) events are based on a 10-minute startup (appropriate for the turbine itself, as compared to the add-on SCR and oxidation catalyst pollution control systems) and a fuel use of 65 mmBtu per SU/SD event. This heat input and the resulting CO_2 emissions are much less than the worse-case emission rate in Table B7-2 which is based on a 30-minute startup time and a total SU/SD heat input of 409 mmBtu.
3. The resulting overall CO_2 emission rate has been increased by 2% to account for potential uncertainties in operating load projections, and to account for startup periods which may exceed 10-minutes in duration.

TABLE B7-10. Expected CO_2 emission rates for the GE LMS100 GTs at the Ocotillo Power Plant based on the projected operation in the Years 2019 and 2023.

Year 2019 Projected Operation[1]	Duaration, % of Total	Emissions, lb/yr	Annual Average Emission Rate, lb/MWh
Startup / Shutdown		1,475,068	
Low Load: ≤ 45%	52%	38,581,804	
Mid Load: >45% ≤ 85%	31%	17,128,839	
High Load: >85% - 100%	17%	8,596,142	
TOTAL	**100%**	**65,781,854**	**1,460**

Year 2023 Projected Operation[1]	Duaration, % of Total	Emissions, lb/yr	Annual Average Emission Rate, lb/MWh
Startup / Shutdown		2,752,447	
Low Load: ≤45%	38%	95,682,509	
Mid Load: >45% ≤85%	30%	42,479,360	
High Load: >85% - 100%	32%	21,318,350	
TOTAL	**100%**	**162,232,666**	**1,450**

Footnotes

1. The projected operation, including the number of startup/shutdown events per year and the gross generation at each load range is from the Real Time (RT) Simulation analysis of expected GT operation.
2. The emission rate for each startup/shutdown event is based on a 10-minute startup event and a fuel use of 43 MMBtu per startup and 22 MMBtu per shutdown for a total of 65 MMBtu per SU/SD event.
3. The CO_2 emission rate at each load level is from Table B7-9.
4. The resulting overall CO_2 emission rate has been increased by 2% to account for potential uncertainties in projecting the worse case operation, and to account for startup periods which may exceed 10-minutes in duration.

7.8.2.3 Proposed Operating Limit.

Based on the above analyses, the operational limit may be based on the level achievable during the lowest load, “worst-case” normal operating conditions. This method was established in the PSD permit for the Pio Pico facility and as upheld by the U.S. EPA EAB. Because the Ocotillo GTs are designed to operate continuously at loads as low as 25% of the maximum load, the lowest achievable BACT emission limit for these GTs based on the average 25% load level is 1,690 lb CO_2/MWh of gross electric output.

The operational limit may also be based on the expected operational loads of the GTs and the resulting expected worse-case emission rate. Based on the above analysis, the expected operation of the GTs would result in an emission rate of 1,460 lb CO_2/MWh of gross electric output including all periods of operation, including periods of startup and shutdown.

Although the operational limit based on the maximum expected operation of the GTs is lower than the limit based on the level achievable during the lowest load, worst-case normal operating conditions, and although APS believes that this higher emission rate is an appropriate BACT limit for these GTs, APS proposes the lower operational limit of 1,460 lb CO_2/MWh of gross electric output as BACT for the control of GHG emissions from these GTs. APS proposes that this limit include all periods of operation, including periods of startup and shutdown.

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[23] "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.

7.8.3 Gas Turbine Maintenance Requirements.

To achieve the proposed BACT emission limits, these gas turbines 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 turbine. Good gas turbine maintenance practices normally include annual boroscopic inspections of the turbine, generator testing, control system inspections, as well as periodic fuel sampling and analysis. Good gas turbine maintenance practices also includes major GT overhauls conducted as recommended by the manufacturer. The frequency of major overhauls is typically every 25,000 "operating" hours. Because GT startup and shutdowns may consume multiple operating hours for purposes of major overhauls (even though the actual startup or shutdown may only take a fraction of a clock hour), a major overhaul is expected to occur approximately every five years.

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

7.8.4 Summary of the Proposed GHG BACT Requirements.

Based on this analysis, APS has concluded that the use of efficient simple cycle gas 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 LMS100 simple-cycle gas turbines. Based on this analysis, APS proposes the following limits as BACT for the control of GHG emissions from the new GTs:

1. The net electric sales for each LMS100 GT will be limited to no more than the design efficiency times the potential electric output on a 3-year rolling average. The design efficiency and potential electric output will be determined during the initial performance test using the methods referenced in 40 CFR 60 Subpart TTTT.
2. The gas turbines shall achieve an initial heat rate of no more than 8,742 Btu per kilowatt hour of gross electric output at 100% load and a dry bulb temperature of 73 ^{o}F.
3. CO_2 emissions may not exceed 1,460 lb CO_2/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. The permittee shall prepare and follow a Maintenance Plan for each GT.

Chapter 8. GT Startup and Shutdown Control Technology Review.

The gas turbine air pollution control systems which represent the best available control technology (BACT) during normal operation, including good combustion practices, water injection, selective catalytic reduction (SCR), and oxidation catalysts, are not operational during the startup and shutdown of the gas turbines.

Water injection is used to reduce NO_x emissions in the diffusion flame combustors of these gas turbines. 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 can increase CO emissions to unacceptable levels. These issues must be carefully balanced when determining when to initiate water injection.

8.1 Startup / Shutdown Event Durations.

The gas turbine air pollution control systems including water injection, selective catalytic reduction (SCR) and oxidation catalysts are not operational during the startup and shutdown of these gas turbines. Water injection is used to reduce NO_x emissions from these GTs 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 GTs, the time required for startup is much shorter than gas turbines used in combined cycle applications. The quick startup times for simple cycle GTs help to minimize emissions during startup and shutdown events. For the LMS100 simple cycle GTs, the length of time for a normal startup, that is, the time from initial fuel firing to the time the unit goes on line and water injection begins, is normally about 10 minutes. However, to allow the oxidation catalysts and SCR pollution control systems to become fully operational, and to address complications in startup events, the duration may be up to 30 minutes. The length of time for a normal shutdown, that is, the time from the cessation of water injection to the time when the flame is out, is normally 11 minutes. Therefore, the normal duration for a startup and shutdown cycle or “event” is 41 minutes.

8.2 Proposed Startup and Shutdown Conditions.

Emissions during periods of startup and shutdown may be limited by limiting the duration of each startup and shutdown event, and they may also be limited by limiting the total number of startup and shutdown hours per year. APS has concluded that the following limits represent BACT for the startup and shutdown of these GTs:

1. The duration of a GT startup shall not exceed 30 minutes for each startup event.
2. The duration of a GT shutdown shall not exceed 11 minutes for each shutdown event.
3. "Startup" is defined as the period beginning with the ignition of fuel and ending 30 minutes later.
4. "Shutdown" is defined as the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased.
5. The total number of hours in startup and shutdown mode for all five LMS100 GTs combined shall not exceed 2,490 hours averaged over any consecutive 12-month period.

Chapter 9. Cooling Tower Control Technology Review.

A new mechanical draft cooling tower will be installed as part of the Ocotillo Power Plant Modernization Project. The specifications for the new cooling tower are summarized in Table B9-1. APS is proposing to utilize a hybrid evaporative cooling system with partial dry cooling. Using a hybrid evaporative cooling system with partial dry cooling will reduce the required volume of makeup water and the wastewater discharge volume by approximately 32% as compared to a fully wet cooling system, but will not substantially change the GT output performance as compared to full evaporative cooling. Fully dry cooling systems have significant output penalties as compared to the wet systems.

TABLE B9-1. Specifications for the new mechanical draft cooling tower.

Total Circulating Water Flow to Cooling Tower, gpm	61,500
Number of Cells	6
Maximum Total Dissolved Solids, ppm	8,000
Design Drift Loss, %	0.0005%

9.1 Cooling Tower Emissions.

In a mechanical draft cooling tower, the circulating cooling water is introduced into the top of the tower. As the water falls through the tower, an air flow is induced in a countercurrent flow using an induced draft fan. A portion of the circulating water evaporates, cooling the remaining water. A small amount of the water is entrained in the induced air flow in the form of liquid phase droplets or mist. Demisters are used at the outlet of cooling towers to reduce the amount of water droplets entrained in the air. The water droplets that pass through the demisters and are emitted to the atmosphere are called *drift loss*. When these droplets evaporate, the dissolved solids in the droplet become particulate matter. Therefore, cooling towers are sources of PM, PM_{10}, and $PM_{2.5}$ emissions.

Cooling tower PM emissions are calculated based on the circulating water flow rate, the total dissolved solids (TDS) in the circulating water, and the design drift loss according to the following equation:

$$E = kQ(60\ \text{min/hr})(8.345\ \text{lb water/gal})\left[\frac{C_{TDS}}{10^6}\right]\left[\frac{\%DL}{100}\right] \qquad \textbf{\textit{Equation 1}}$$

Where,

	E	=	Particulate matter emissions, pounds per hour (lb/hr)
	Q	=	Circulating water flow rate, gallons per minute = 61,500 gpm
	C_{TDS}	=	Circulating water total dissolved solids, parts per million = 8,000 ppm
	DL	=	Drift loss, % = 0.0005%
	k	=	particle size multiplier, dimensionless

The particle size multiplier “k” has been added to the basic AP-42 equation to calculate emissions for various PM size ranges, including PM_{10} and $PM_{2.5}$. AP-42 Section 13.4 presents data that suggests the PM_{10} fraction is 1% of the total PM emission rate. There is no information provided on $PM_{2.5}$ emissions.

Maricopa County had developed an emission factor of 31.5% to convert total cooling tower PM emissions to PM_{10} emissions based on tests performed at the Gila Bend Power Plant. During the PSD permitting of the Hydrogen Energy California (HECA) project by the San Joaquin Valley Air Pollution Control District (SJVAPCD), the applicant used an emission factor of 0.6 to convert cooling tower PM_{10} emissions to $PM_{2.5}$ emissions. This factor was based on data contained in the California Emission Inventory Development and Reporting System (CEIDARS) data base, along with further documentation including an analysis of the emission data that formed the basis of the CEIDARS ratio, and discussions with various California Air Resources Board and EPA research staff. This PSD permit was reviewed and commented upon by the California Energy Commission and EPA Region 9, and these agencies accepted this factor for use in cooling tower $PM_{2.5}$ emission estimates.

Table 4 summarizes the PM, PM_{10}, and $PM_{2.5}$ emissions for the cooling tower based on the particle size multipliers of 0.315 for PM_{10} emissions and 0.189 (i.e., 0.315 x 0.6 = 0.189) for $PM_{2.5}$ emissions, based on these multipliers that have been previously approved in PSD permitting actions.

During the PSD permitting of the Hydrogen Energy California (HECA) project by the San Joaquin Valley Air Pollution Control District (SJVAPCD), the applicant used an emission factor of 0.6 to convert cooling tower PM_{10} emissions to $PM_{2.5}$ emissions. This factor was based on data contained in the California Emission Inventory Development and Reporting System (CEIDARS) data base, along with further documentation including an analysis of the emission data that formed the basis of the CEIDARS ratio, and discussions with various California Air Resources Board and EPA research staff. This PSD permit was reviewed and commented upon by the California Energy Commission and EPA Region 9, and these agencies accepted this factor for use in cooling tower $PM_{2.5}$ emission estimates.

Table B9-2 presents the calculated PM, PM_{10}, and $PM_{2.5}$ emissions for the cooling tower, using particle size multipliers of 0.315 for PM_{10} emissions and 0.189 (0.315 * 0.6) for $PM_{2.5}$ emissions, based on these multipliers that have been previously approved in PSD permitting actions.

TABLE B9-2. Potential emissions for the new mechanical draft cooling tower.

POLLUTANT		*Q* Cooling Tower Flowrate	C_{TDS} Blowdown TDS Conc.	%DL Drift Loss	*k* Particle Size Multiplier	Potential to Emit	
		gallon/min	ppm	%		lb/hr	ton/yr
Particulate Matter	PM	61,500	8,000	0.0005%	1.00	1.23	5.39
Particulate Matter	PM_{10}	61,500	8,000	0.0005%	0.315	0.39	1.70
Particulate Matter	$PM_{2.5}$	61,500	8,000	0.0005%	0.189	0.23	1.02

9.2 BACT Baseline.

There are SIP requirements or new source performance standards for this cooling tower.

9.3 Step 1. Identify all available control technologies.

In a review of recently issued permits for new power plants equipped with cooling towers, demisters or mist eliminators are the only identified control technology to limit PM emissions. Demisters can be designed for various levels of drift loss control. The cooling tower drift loss control requirements representing BACT for recently permitted power plants are summarized in Table B9-3. From Table B9-3, the required drift loss control requirements for permits issued since 2007 range from 0.0005% to 0.002%. To reduce drift loss, additional layers of demisters must be installed in the cooling tower. This can make the cooling tower taller and increases the fan horsepower and auxiliary power requirements.

In addition to the use of high efficiency mist eliminators, available plant cooling options include:

1. 100% wet cooling systems which uses only cooling towers or wet surface to air coolers (WSACs),
2. Hybrid evaporative/dry systems using a combination of a cooling tower and air cooled heat exchangers (ACHEs), and
3. 100% dry cooling systems.

All wet systems, including the hybrid systems, have wet cooling towers which are sources of potential PM emissions. Fully dry ACHEs do not use water and can essentially eliminate cooling tower related PM, PM_{10}, and $PM_{2.5}$ emissions. Table B9-4 shows the estimated impacts of the use of 100% wet, hybrid, and 100% dry cooling systems on the performance of the GTs. From Table B9-4, the use of 100% dry cooling would reduce the net plant output at an ambient temperature of 105 ^{o}F by 16.1 MW per GT (a 15% reduction), or a total plant derating of approximately 80 MW. The use of 100% dry cooling would also reduce the GT efficiency and increase GHG emissions per MWh of electric output. At the same temperature, the hybrid system would have a minimal impact on the plant output and efficiency, yet the hybrid system would reduce water consumption by 32%, from 207 gallons per MWh for the 100% evaporative system to 141 gallons per MWh for the hybrid system.

Other possible methods to decrease PM emissions from cooling towers include water treatment methods such as the use of demineralized water. However, demineralizing the makeup water may not significantly change the TDS concentration in the *circulating cooling water*. And because potential PM, PM_{10}, and $PM_{2.5}$ emissions from cooling towers are a function of the circulating water TDS (NOT the makeup water TDS), the use of demineralized makeup cooling water would not affect the maximum potential emissions from the cooling tower. Rather, demineralizing the makeup water would increase the *cycles of concentration* which the cooling tower could operate at, but it would not change the maximum TDS concentration in the circulating cooling water.

TABLE B9-3. Cooling tower BACT requirements for recently permitted power plants.

Facility	Date	State	Drift Loss
Longview Power Plant	Mar. 2014	VA	0.002%
Pio Pico Energy Center	Dec. 2012	CA	0.001%
Consumers Energy Karn Weadock	Dec. 2009	MI	0.0005%
AEP John W. Turk, Jr. Power Plant	Nov. 2008	AR	0.0005%
Santee Cooper - Pee Dee Station	December-07	SC	0.0005%
Seminole Electric - Palatka Unit 3	August-07	FL	0.0005%
Deseret Power Coop - Bonanza	August-07	UT	0.001%
LS Power - Longleaf Energy Center	May-07	GA	0.001%
Southern Montana Electric-Highwood	May-07	MT	0.002%

TABLE B9-4. Estimated GE LMS 100 GT performance at the Ocotillo Power Plant for different types of intercooler cooling systems at 105 oF and with inlet chilling.

Cooling System Design	Gross Output, MW	Net Output, MW	Net Unit Heat Rate, Btu/kWh
100% Dry	92.2	86.2	9,566
100% Wet	107.4	102.4	9,125
Hybrid	107.4	102.2	9,138

9.4 Step 2. Identify the technically feasible control options.

The technically feasible control options include 100% wet, hybrid, and 100% dry cooling systems. However, because the use of 100% wet cooling systems would increase circulating water requirements and PM emissions, they are not considered further in this analysis. As discussed above, 100% dry ACHEs would so dramatically impact the plant output capacity on hot days as to result in redefining the source. Never-the-less, fully dry cooling systems will be considered further in this analysis.

9.5 Step 3. Rank the technically feasible control options.

The only technically feasible control option for wet mechanical draft cooling towers is the use of high efficiency drift eliminators. Therefore, high efficiency drift eliminators are the top ranked control option. The highest level of control commercially available is 0.0005%.

In addition, fully dry ACHEs do not use water and can essentially eliminate cooling tower related PM, PM_{10}, and $PM_{2.5}$ emissions.

9.6 Step 4. Evaluate the most effective controls.

The only feasible control technology for mechanical draft cooling towers is high efficiency drift eliminators. From Table B9-3, the required drift loss control requirements for permits issued in 2007 ranged from 0.0005% to 0.002%. The highest level of control commercially available is 0.0005%.

With respect to the use of 100% dry cooling systems, from Table B9-4, the use of 100% dry cooling would reduce the net plant output at an ambient temperature of 105 ^{o}F by 16.1 MW per GT (a 15% reduction), or a total plant derating of approximately 80 MW. The use of 100% dry cooling would also reduce the GT efficiency and increase GHG emissions per MWh of electric output. This reduction in plant capacity on hot summer days would have a very high cost. The capital and auxiliary power requirements are also much higher for the 100% dry cooling systems. The capital costs for the hybrid system are estimated at $9,888,000 as compared to $13,813,000 for the 100% dry cooling system[24]. To annualize these capital costs, the total capital cost is multiplied by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate
n = control system (project) life, years

For a project life of 25 years and an interest rate of 7%, the CRF is 0.0858 and the annual cost of the additional capital investment is $336,800. If a 100% dry cooling system *eliminated* the hybrid cooling system emissions, the cost effectiveness for the use of 100% dry cooling as a BACT control option – **based only on the additional capital cost -** would be $62,500 per ton of PM controlled, $198,000 per ton of PM_{10} controlled, and $330,000 per ton of $PM_{2.5}$ controlled. These costs do not include the expected much higher lost capacity and energy sales during peak power periods, and these costs do not include the substantially higher auxiliary electric loads required to operate the 100% dry cooling systems. Therefore, the use of 100% dry cooling systems is an economically infeasible BACT control option for the control of PM, PM_{10}, and $PM_{2.5}$ emissions for this Project.

9.7 Step 5. Propose BACT.

Based on this analysis, APS has concluded that the following limits represent BACT for the proposed new cooling tower:

1. The cooling tower drift eliminators shall be designed for a drift loss of no more than 0.0005% of the total circulating water flow.
2. The total dissolved solids (TDS) concentration in wet cooling circulation water may not exceed 8,000 parts per million (ppm) on weight basis.

[24] *Arizona Public Service Company Ocotillo CT 3-7 Expansion Project Cooling System Study*, Kiewit Power Engineers, Project No. 2013-027, Rev 0 – June 6, 2013, page 7-4.

Chapter 10. Emergency Generator Control Technology Review.

The Ocotillo Modernization Project will include the proposed installation of two 2.5 megawatt (MWe) emergency generators powered by diesel (compression ignition) engines. Because these new generators will be used as emergency diesel generators, APS is proposing operational limits for each generator of no more than 500 hours in any 12 consecutive month period. Table B10-1 is a summary of the technical specifications for each emergency generator.

TABLE B10-1. Technical specifications for the proposed new emergency generators.

Generator Standby Rating, kW	2, 500
Engine Type	Diesel (Compression Ingnition)
Engine Power at Standby Output, brake-horsepower	3,750
Engine Displacement, L	78
Engine Cylinders	V-16
Engine Displacement per Cylinder, L	4.88
Maximum Diesel Fuel Consumption Rate, gal/hr	175
Exhaust Gas Flowrate, acfm	19,600
Exhaust Gas Temperature, ^{o}F	794
NOx Emission Controls	None
PM and VOC Emission Controls	None

Footnotes

The maximum generator output rating, fuel consumption rating, emissions, and flowrates are based on the generator standby rating, which is the maximum short term capacity of the generator.

10.1 New Source Performance Standards.

Emissions for the diesel engines are based on the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart IIII, promulgated July, 2006. Under 40 CFR § 60.4202(b)(2), for 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR § 89.112 and 40 CFR § 89.113 for all pollutants:

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

The emission standards under 40 CFR § 89.112 include exhaust emission standards for NOx, CO, hydrocarbons, and particulate matter. The emission standards for engines with a rated power greater than 560 kW (750 hp) in Table 1 for Model Year 2006 and later engines include the following:

Pollutant	Emission Standard	
	g/kW-hr	g/hp-hr
NMHC + NO_x	6.4	4.77
CO	3.5	2.61
PM	0.2	0.15

10.2 Emergency Generator Emissions.

With this application, APS is proposing to install diesel generators which comply with the Tier 2 emission standards under 40 CFR § 89.112. These standards are applicable to emergency stationary RICE. Under 40 CFR § 60.4211, an emergency stationary ICE may not operate for more than 100 hours per year, except that there is no limit for emergency operation. In addition to these federal requirements, Maricopa County Rule 324 effectively limits the hours of operation to 100 hours for testing and maintenance, and 500 hours total including all emergency periods. Therefore, the potential emissions from the emergency generators have been based on 500 hours of operation per 12 month period. The potential emissions for each 2.5 MW diesel-fired emergency electric generator, and for both generators combined, based on these proposed requirements, are summarized in Table B10-2.

TABLE B10-2. Potential emissions for each 2.5 MW generator and for both generators combined.

POLLUTANT		Emission Factor	Power Output	Potential to Emit, Each Generator		Potential to Emit, Both Generators
		g/hp-hr	hp	lb/hr	ton/year	ton/year
Carbon Monoxide	CO	2.61	3,750	21.56	5.39	10.8
Nitrogen Oxides	NO_x	4.77	3,750	39.65	9.86	19.7
Particulate Matter	PM	0.15	3,750	1.24	0.31	0.62
Particulate Matter	PM_{10}	0.15	3,750	1.24	0.31	0.62
Particulate Matter	$PM_{2.5}$	0.15	3,750	1.24	0.31	0.62
Sulfur Dioxide	SO_2	0.0044	3,750	0.037	0.01	0.0184
Vol. Org. Cmpds	VOC	0.20	3,750	1.65	0.413	0.83
Sulfuric Acid Mist	H_2SO_4	4.4E-04	3,750	0.0037	0.00	0.00184
Fluorides	F	7.9E-04	3,750	0.0065	0.00	0.00326
Lead	Pb	2.7E-05	3,750	0.0002	0.00	0.00011
Carbon Dioxide	CO_2	476.7	3,750	3,937.7	984.43	1,968.86
Greenhouse Gases	CO_2e	478.4	3,750	3,951.2	987.81	1,975.61

Footnotes

1. Potential emissions are based on 500 hours per year of operation for each engine – generator set.
2. The CO, NOx, PM, and VOC emission rates are based on the Tier 2 engine standards in 40 CFR §89.112, and a maximum engine rating of 3,750 horsepower.
3. All PM emissions are also assumed to be PM_{10} and $PM_{2.5}$ emissions.
4. SO_2 emissions are based on a maximum fuel consumption rate of 175 gal/hr, and a sulfur content of 0.0015%.
5. VOC emissions are based on an estimated NMHC emission rate of 0.2 g/hp-hr.
6. Sulfuric acid mist emissions are based on 10% conversion of SO_2 to SO_3 in the flue gas.
7. Lead and fluoride emissions are based on the emission factor for oil combustion in the *U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42*, section 1.3, oil combustion, Tables 1.3-10 and 1.3-11., respectively, AND a maximum fuel oil consumption rate of 175 gallons per hour.
8. Emission factors for GHG emissions 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.

10.3 Carbon Monoxide (CO) Control Technology Review.

Carbon monoxide (CO) is emitted from diesel engines as a result of incomplete combustion. Therefore, the most direct approach for reducing CO emissions (and also reduce the other related pollutants) is to improve combustion. Incomplete combustion also leads to emissions of diesel particulate matter, volatile organic compounds (VOC) and organic hazardous air pollutants (HAP). CO emissions as well as diesel particulate matter, VOC, and organic HAP emissions may also be reduced using post combustion emission control systems including oxidation catalyst systems. When used on diesel engines, these oxidation catalyst systems are often called diesel oxidation catalysts.

10.3.1 BACT Baseline.

The emergency engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. In accordance with 40 CFR §60.4201, manufacturers of new emergency stationary CI engines must meet the following:

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?
(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.
(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

In addition, in accordance with 40 CFR §60.4207(b), these engines must use diesel fuel that meets the requirements of 40 CFR §80.510(b) for nonroad diesel fuel. The sulfur content requirement for nonroad (NR) diesel fuel in 40 CFR §60.4207(b)(1)(i) is 15 ppm.

The standards are summarized in the table below.

Diesel engine standards under 40 CFR 60, Subpart IIII.

POLLUTANT		Emergency CI Engine Tier 2 Standards	
		g/kWhr	g/hp-hr
Carbon Monoxide	CO	3.5	2.61
Nitrogen Oxides	NO_x	6.4*	4.77*
Particulate Matter	PM	0.20	0.15
Non-Methane Hydrocarbons	NMHC	n/a	n/a

Footnotes

* The NO_x standards for Tier 2 engines are the sum of the NOx and NMHC.
The Tier 2 standards are for engines greater than 750 horsepower (hp).

10.3.2 STEP 1. Identify All Available Control Technologies.

Table B10-3 is a summary of CO emission limits for diesel generators from the U.S. EPA's RACT / BACT / LAER database. From Table B10-3, a total of 10 of the 12 generators identified have the Tier 2 and Tier 4 CO emission limit of 2.6 grams per horsepower hour (g/hp-hr). (The other two units have pound per hour limits. There is insufficient information in the database to determine the equivalent limit expressed in g/hp-hr).

The South Coast Air Quality Management District's LAER/BACT determinations (available at http://www.aqmd.gov/home/permits/bact/guidelines/i---scaqmd-laer-bact) did not have any listed determinations newer than 2003. The Bay Area Air Quality Management District BACT Guideline for diesel-fueled emergency engines with a rating of more than 750 hp, based on the Airborne Toxic Control Measures (ATCMs) promulgated by the California Air Resources Board (CARB) also lists a BACT CO emission limit of 2.6 g/hp-hr. The San Joaquin Valley Air Pollution Control District BACT Guideline, 3.1.1, requires the latest EPA Tier certification level for applicable horsepower range.

Based on this review, Good Combustion Practices (GCP) and Diesel Oxidation Catalysts (DOC) have potential for applicability to these generators.

10.3.3 STEP 2. Identify Technically Feasible Control Technologies.

Good combustion practices and diesel oxidation catalysts are both technically feasible options.

10.3.4 STEP 3. Rank the Technically Feasible Control Technologies.

Based on the above data, the use of Good Combustion Practices (Tier 2) engines, and the use of GCP combined with diesel oxidation catalysts (Tier 4 engines), both can achieve a CO emission rate of 2.6 grams per horsepower hour.

Note that while diesel oxidation catalysts may reduce CO emissions, based on the fact that the Tier 2 and Tier 4 standards have the same CO emission standard, and the fact that engines are designed to meet all emission standards (that is, the engine may have higher uncontrolled CO emissions to reduce uncontrolled NO_x emissions), we cannot conclude that an engine designed to the Tier 4 standard would actually reduce CO emissions from the generator sets as compared to the Tier 2 engine.

TABLE B10-3. Carbon monoxide (CO) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	2.6 g/hp-hr
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	2.6 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		2.6 g/hp-hr
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	2.6 g/hp-hr
CF Industries Nitrogen, LLC - Port Neal	IA	07/12/13	180 gal/hr	2.6 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	17.35 lb/hr
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	2.6 g/hp-hr
Hess Newark Energy Center	NJ	11/01/12	200 hr/yr	11.56 lb/hr
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	2.6 g/hp-hr
Point Thomson Production Facility	AK	08/20/12	1,750 kW	2.6 g/hp-hr
Pyramax Ceramics, LLC	SC	02/08/12	757 hp	2.6 g/hp-hr
Palmdale Hybrid Power Project	CA	10/18/11	2,683 hp	2.6 g/hp-hr

10.3.5 STEP 4. Evaluate the Most Effective Controls.

Because the use of Good Combustion will achieve the required CO emission rate of 2.6 grams per horsepower hour, no further analysis is required.

10.3.6 STEP 5. Proposed Carbon Monoxide (CO) BACT Determination.

Based on this analysis, Arizona Public Service (APS) has concluded that the use of good combustion practices in combination with the use of diesel oxidation catalysts represents the best available control technology (BACT) for the control of CO emissions from the proposed diesel generators. APS proposes the following limits as BACT for the control of CO emissions from the emergency generators:

1. Carbon monoxide (CO) emissions may not exceed the Tier 2 standard under 40 CFR § 89.112 for generator sets manufactured after the 2006 model year of 2.61 g/hp-hr.
2. The operation of each generator may not exceed 500 hours per year.

10.4 Nitrogen Oxides (NO_x) Control Technology Review.

Based on the PSD applicability analysis in Chapter 4 of the construction permit application, the proposed Ocotillo Generation Project will not result in a significant net emissions increase for NO_x emissions. Therefore, the Project is not a major modification for NO_x emissions, and the Project is therefore not subject to the application of BACT under the PSD program. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of nitrogen oxides (NO_x). Therefore, the following BACT analysis is being conducted to comply with Maricopa County Rule 241, Section 301.1.

In accordance with Maricopa County Air Quality Department's memorandum "REQUIREMENTS, PROCEDURES AND GUIDANCE IN SELECTING BACT and RACT", revised July, 2010, section 8, "To streamline the BACT selection process, the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVAPCD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above." The following is an analysis of recent NO_x BACT determinations in California. Arizona Public Service (APS) proposes a BACT level which reflects these NO_x BACT determinations.

10.4.1 BACT Baseline.

These engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. The NO_x emission standard for non-emergency generator sets manufactured after the 2014 model year (Tier 4 standard) is 0.5 g/hp-hr. The NO_x emission standard for emergency engines greater than 750 hp is 4.8 g/hp-hr (Tier 2 standard). Note that the Tier 2 standard is the sum of the NO_x and non-methane hydrocarbons (NMHC). In addition, Maricopa County rule 324 limits NO_x emissions to 6.9 g/hp-hr.

10.4.2 BACT Control Technology Determinations.

Table B10-4 is a summary of NO_x emission limits for similar emergency generators. The limits in Table B10-4 indicate Tier 2 emission limits for the majority of permitted generators. The most stringent limitation is the Tier 4 standard of 0.50 g/hp-hr for the Cronus Chemicals, LLC facility in Illinois.

The Bay Area Air Quality Management District BACT Guideline for diesel-fueled emergency engines with a rating of more than 750 hp, based on the Airborne Toxic Control Measures (ATCMs) promulgated by the California Air Resources Board (CARB) lists a BACT NO_x emission limit of 4.77 g/hp-hr. The San Joaquin Valley Air Pollution Control District BACT Guideline, 3.1.3, requires the latest EPA Tier certification level for the applicable horsepower range; in that reference, equal to 6.9 g/hp-hr.

10.4.3 Available Control Technologies.

The available control technologies for diesel generators includes good combustion practices (engine design), and Selective Catalytic Reduction (SCR). Selective non-catalytic reduction (SNCR) is an available NO_x control technology for boilers and other external combustion sources, but it is not technically feasible for internal combustion engines.

TABLE B10-4. Nitrogen oxides (NO_x) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	0.50 g/hp-hr
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	4.46 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		2.85 g/hp-hr
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	4.46 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	27.8 lb/hr
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	4.8 g/hp-hr
Hess Newark Energy Center	NJ	11/01/12	200 hr/yr	18.53 lb/hr
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	4.47 g/hp-hr
Point Thomson Production Facility	AK	08/20/12	1,750 kW	4.8 g/hp-hr
Pyramax Ceramics, LLC	SC	02/08/12	757 hp	2.98 g/hp-hr
Palmdale Hybrid Power Project	CA	10/18/11	2,683 hp	4.8 g/hp-hr
Highlands Biorefinery and Cogen Plant	FL	09/23/11		4.8 g/hp-hr

10.4.4 SCR Cost Analysis.

The generator sets with Tier 4 engines are equipped with selective catalytic reduction (SCR) systems and are designed to achieve a lower NO_x emission rate of 0.50 g/hp-hr. Based on the operational limit of 500 hours per year for each emergency generator, the potential NO_x emissions, based on the use of Tier 4 engines, would be 4.13 lb/hr and 1.03 tons per year. This would reduce potential NO_x emissions from these generators by 8.8 tons per year for each genset, and 17.7 tons per year for both gensets combined.

The generator sets with Tier 4 engines also have a higher capital cost. The additional total capital cost for each genset equipped with Tier 4 engines is $400,000 per genset, or a total additional capital cost of $800,000 for both gensets. To annualize these capital costs, the total capital cost is multiplied by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate
n = control system (project) life, years

For a project life of 25 years and an interest rate of 7%, the CRF is 0.0858 and the annual cost of the additional capital investment is $34,320 per year. Based on a NOx reduction of 8.8 tons per year per genset, the cost effectiveness for the use of Tier 4 engines as a NO_x BACT control option – based only on the additional capital cost - would be $3,890 per ton of NO_x controlled. The actual Tier 4 engine costs would be higher due to increased operating and maintenance (O&M) costs, including the additional costs for ammonia and additional maintenance costs. Given the fact that the actual emissions from these emergency units will likely be an order of magnitude lower than the potential emissions, these costs would increase to well over $10,000 per ton. This high cost demonstrates that the use of Tier 4 engines equipped with selective catalytic reduction (SCR) is not an economically feasible control technology option for these emergency generators.

10.4.5 Proposed NO_x BACT Determination.

Based on the PSD applicability analysis in Chapter 4 of the construction permit application, the proposed Project is not subject to the application of NOx BACT under the PSD program. However, this NOx BACT analysis has been performed to address Maricopa County Rule 241, Section 301.1 requirement. Maricopa BACT guidance states that the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVAPCD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above.

APS has reviewed California BACT determines and found that the lowest emission limit is 4.77 g/hp-hr. Although not required, the top down BACT costing analysis also indicates that an emission limit of 4.77 g/hp-hr is appropriate. Based on this analysis, APS has concluded that the use of good combustion practices and the use of Tier 2 engines represents BACT for the control of NO_x emissions from the proposed emergency diesel generators. APS proposes the following limits as BACT for the control of NO_x emissions from the emergency diesel generators:

1. Nitrogen oxide (NO_x) emissions may not exceed 4.77 g/hp-hr.
2. The operation of each emergency generator may not exceed 500 hours per year.

10.5 Particulate Matter (PM) and $PM_{2.5}$ Control Technology Review.

Emissions of particulate matter (PM), including particulate matter with aerodynamic particle sizes less than 10 microns (PM_{10}), and particulate matter with aerodynamic particle sizes less than 2.5 microns ($PM_{2.5}$) from diesel generators result from PM in the combustion air, from ash in the fuel, engine wear, and from products of incomplete combustion. For this analysis, all PM emissions from the diesel generators are also assumed to be PM_{10} and $PM_{2.5}$ emissions. Since ultra-low sulfur diesel fuel has very little ash, fuel ash is not a significant source of PM emissions.

10.5.1 BACT Baseline.

These engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. The PM emission standard for non-emergency generator sets manufactured after the 2014 model year (Tier 4 standard) is 0.022 g/hp-hr. The PM emission standard for emergency engines greater than 750 hp is 0.15 g/hp-hr (Tier 2 standard).

10.5.2 STEP 1. Identify All Available Control Technologies.

Table B10-5 is a summary of PM emission limits for diesel generators from the U.S. EPA's RACT / BACT / LAER database. From Table B10-5, all of the generators identified have the Tier 2 PM emission limit of 0.15 grams per horsepower hour (g/hp-hr) except for the Cronus Chemicals, LLC facility, which has a limit of 0.075 g/hp-hr. That limit is the interim Tier 4 emission standard for generator sets larger than 900 kW manufactured after Year 2010. (Two units have pound per hour limits. There is insufficient information in the database to determine the equivalent limit expressed in g/hp-hr).

The South Coast Air Quality Management District's LAER/BACT determinations (available at http://www.aqmd.gov/home/permits/bact/guidelines/i---scaqmd-laer-bact) did not have any listed determinations newer than 2003. The Bay Area Air Quality Management District BACT Guideline for diesel-fueled emergency engines with a rating of more than 750 hp, based on the Airborne Toxic Control Measures (ATCMs) promulgated by the California Air Resources Board (CARB) also lists a BACT PM emission limit of 0.15 g/hp-hr. The San Joaquin Valley Air Pollution Control District BACT Guideline, 3.1.1, requires the latest EPA Tier certification level for applicable horsepower range.

Based on this review, Good Combustion Practices (GCP) and Diesel Oxidation Catalysts (DOC) have potential for applicability to these generators.

10.5.3 STEP 2. Identify Technically Feasible Control Technologies.

Good combustion practices and diesel oxidation catalysts are both technically feasible options.

10.5.4 STEP 3. Rank the Technically Feasible Control Technologies.

Based on the above data, the use of Good Combustion Practices (Tier 2 engines) can achieve a PM emission rate of 0.15 g/hp-hr. The use of GCP combined with diesel oxidation catalysts (Tier 4 engines) can achieve a PM emission rate of 0.022 g/hp-hr.

TABLE B10-5. Particulate matter (PM) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	0.075 g/hp-hr
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	0.15 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		0.15 g/hp-hr
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	0.15 g/hp-hr
CF Industries Nitrogen, LLC - Port Neal	IA	07/12/13	180 gal/hr	0.15 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	0.99 lb/hr
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	0.15 g/hp-hr
Hess Newark Energy Center	NJ	11/01/12	200 hr/yr	0.59 lb/hr
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	0.15 g/hp-hr
Point Thomson Production Facility	AK	08/20/12	1,750 kW	0.15 g/hp-hr
Palmdale Hybrid Power Project	CA	10/18/11	2,683 hp	0.15 g/hp-hr

10.5.1 STEP 4. Evaluate the Most Effective Controls.

The generator sets with Tier 4 engines are equipped with diesel oxidation catalyst systems and are designed to achieve a lower PM emission rate of 0.022 g/hp-hr. Based on the operational limit of 500 hours per year for each emergency generator, the potential PM and $PM_{2.5}$ emissions for each generator, based on the use of Tier 4 engines, would be 0.18 pounds per hour and 0.05 tons per year. This would reduce potential PM and $PM_{2.5}$ emissions from these generatos by 0.26 tons per year for each genset, and 0.53 tons per year for both gensets combined.

As noted above, the generator sets with Tier 4 engines also have a higher capital cost. The additional capital cost for each genset equipped with Tier 4 engines is $400,000 per genset, or a total additional capital cost of $800,000 for both generators. To annualize these capital costs, the total capital cost is multiplied by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate
n = control system (project) life, years

For a project life of 25 years and an interest rate of 7%, the CRF is 0.0858 and the annual cost of the additional capital investment is $34,320. Based on a PM reduction of 0.26 tons per year per genset, the cost effectiveness for the use of Tier 4 engines as a PM BACT control option – based only on the additional capital cost - would be $130,000 per ton of PM controlled. The actual Tier 4 engine costs would be higher due to increased operating and maintenance (O&M) costs. This very high cost demonstrates that the use of Tier 4 engines equipped with diesel oxidation catalysts is not an economically feasible PM and $PM_{2.5}$ control technology option for these emergency generators.

Based on this cost evaluation, the next most effective PM and $PM_{2.5}$ control option is the use of Tier 2 engines.

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

Based on this analysis, APS has concluded that the use of good combustion practices and the use of Tier 2 engines represents BACT for the control of PM emissions from the proposed diesel generators. APS proposes the following limits as BACT for the control of PM emissions from the emergency generators:

1. Particulate matter (PM) emissions may not exceed 0.15 g/hp-hr.
2. The operation of each generator may not exceed 500 hours per year.

10.6 Volatile Organic Compound (VOC) Control Technology Review.

Based on the NANSR applicability analysis in Chapter 4 of the construction permit application, the proposed Ocotillo Generation Project will not be subject to the application of BACT under the PSD program or LAER under the NANSR program. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of VOC emissions. Therefore, the following BACT analysis is being conducted to comply with Maricopa County Rule 241, Section 301.1.

In accordance with Maricopa County Air Quality Department's memorandum "REQUIREMENTS, PROCEDURES AND GUIDANCE IN SELECTING BACT and RACT", revised July, 2010, section 8, "To streamline the BACT selection process, the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above." The following is an analysis of recent VOC BACT determinations. Arizona Public Service (APS) proposes a BACT level which reflects these VOC BACT determinations.

Like CO emissions, VOC is emitted from diesel generators as a result of incomplete combustion. Therefore, the most direct approach for reducing VOC emissions (and also reduce the other related pollutants) is to improve combustion. Incomplete combustion also leads to emissions of organic hazardous air pollutants (HAP) such as formaldehyde. VOC and organic HAP emissions may also be reduced using post combustion control systems including diesel oxidation catalyst systems.

10.6.1 BACT Baseline.

These engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. The non-methane hydrocarbon (NMHC) emission standard for non-emergency generators manufactured after the 2014 model year (Tier 4) is 0.14 g/hp-hr. The Tier 2 emission standard for NMHC is actually a combined NO_x and NMHC standard for emergency engines greater than 750 hp is 4.77 g/hp-hr.

10.6.2 BACT Control Technology Determinations.

Table B10-6 is a summary of VOC emission limits for similar emergency generators. The limits in Table B9-6 indicate VOC or NMHC emission limits ranging from 0.15 to 0.30 g/hp-hr. The Bay Area Air Quality Management District BACT Guideline for diesel-fueled emergency engines with a rating of more than 750 hp, based on the Airborne Toxic Control Measures (ATCMs) promulgated by the California Air Resources Board (CARB) lists a BACT NO_x + NMHC emission limit of 4.8 g/hp-hr, equal to the Tier 2 standard. The San Joaquin Valley Air Pollution Control District BACT Guideline, 3.1.1, requires the latest EPA Tier certification level for the applicable horsepower range.

10.6.3 Available Control Technologies.

The available control technologies for diesel generators includes good combustion practices (engine design), and diesel oxidation catalysts. The reduction potential for VOC emissions for oxidation catalysts is expected to be approximately 50 to 60%. However, the VOC reduction capabilities based on the engine Tier standards is more difficult to estimate for several reasons. First, VOC emissions do not have a specific standard; the standard is for non-methane hydrocarbons (NMHC). The second reason is because the Tier 4 standards have a specific NMHC standard, while the Tier 2 standard includes NO_x and NMHC *combined*.

TABLE B10-6. Volatile organic compound (VOC)) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	0.30 g/hp-hr
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	0.31 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		0.15 g/hp-hr
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	0.31 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	3.93 lb/hr
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	1.04 lb/hr
Hess Newark Energy Center	NJ	11/01/12	200 hr/yr	2.62 lb/hr
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	0.30 g/hp-hr
Pyramax Ceramics, LLC	SC	02/08/12	757 hp	0.30 g/hp-hr

10.6.4 Diesel Oxidation Catalyst Cost Analysis.

The generator sets with Tier 4 engines are equipped with diesel oxidation catalyst systems and are designed to achieve a NMHC emission rate of 0.14 g/hp-hr. Again, the Tier 2 standard includes NO_x and NMHC *combined*. Based on the operational limit of 500 hours per year for each emergency generator, the potential VOC emissions, based on the use of Tier 4 engines, would be 1.17 pounds per hour and 0.29 tons per year. This would reduce potential VOC emissions from these generators by 0.12 tons per year for each genset, and 0.24 tons per year for both gensets combined.

As noted above, the generator sets with Tier 4 engines also have a higher capital cost. The additional capital cost for each genset equipped with Tier 4 engines is $400,000 per genset, or a total additional capital cost of $800,000 for both generators. To annualize these capital costs, the total capital cost is multiplied by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate

n = control system (project) life, years

For a project life of 25 years and an interest rate of 7%, the CRF is 0.0858 and the annual cost of the additional capital investment is $34,320. Based on a VOC reduction of 0.12 tons per year per genset, the cost effectiveness for the use of Tier 4 engines as a VOC BACT control option – based only on the additional capital cost - would be $285,000 per ton of VOC controlled. The actual Tier 4 engine costs would be higher due to increased operating and maintenance (O&M) costs. This very high cost demonstrates that the use of Tier 4 engines equipped with diesel oxidation catalysts is not an economically feasible VOC control technology option for these emergency generators.

10.6.5 Proposed VOC BACT Determination.

Based on this analysis, APS has concluded that the use of good combustion practices and Tier 2 engines represents BACT for the control of VOC emissions from the proposed diesel generators. APS proposes the following limits as BACT for the control of VOC emissions from the emergency generators:

1. Volatile organic compound (VOC) emissions may not exceed 0.20 g/hp-hr.
2. The operation of each generator may not exceed 500 hours per year.

10.7 Greenhouse Gas (GHG) Emissions Control Technology Review.

GHG emissions from diesel engine driven electric generators 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 diesel fuel combustion, based on the combustion of No. 2 distillate fuel oil, is 73.96 kg per mmBtu, equal to 116.6 pounds per million Btu, based on the higher heating value (HHV) of natural gas.

Methane (CH_4) emissions result from incomplete combustion. The federal *Mandatory Greenhouse Gas Reporting rule*, 40 CFR Part 98, Table C-2 lists a methane emission factor for the combustion of No. 2 distillate fuel oil of 0.003 kg/mmBtu (0.0066 lb/mmBtu).

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 the combustion of No. 2 distillate fuel oil of 0.0006 kg/mmBtu (0.0013 lb/mmBtu).

Potential GHG emissions for each generator based on the proposed operating limit of 500 hours per year are summarized in Table B10-7. From Table B10-7, CO_2 emissions account for 99.7% of the total GHG emissions. ***Because CO_2 emissions account for the vast majority of GHG emissions from these generators, this control technology review for GHG emissions will focus on CO_2 emissions.***

TABLE B10-7. Potential greenhouse gas (GHG) emissions for each 2,500 kW diesel generator.

Pollutant		Emission Factor		Total GHG Emission Factor		Heat Input Capacity	Potential to Emit, EACH GENSET	
		kg/mmBtu	lb/mmBtu	CO_2e Factor[4]	lb/mmBtu	mmBtu/hr	lb/hour	tons/yr
Carbon Dioxide	CO_2	73.96	163.05	1	163.05	24.2	3,937.7	984.4
Methane	CH_4	3.0E-03	0.0066	25	0.17	24.2	4.0	1.0
Nitrous Oxide	N_2O	6.0E-04	0.0013	298	0.39	24.2	9.5	2.4
TOTAL GHG EMISSIONS, AS CO_2e					**163.6**		**3,951.2**	**987.8**

Footnotes

1. Potential emissions in tons per year are based on limiting the operation of each emergency generator to 500 hours per year.

2. The emission factors for the 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.

10.7.1 BACT Baseline.

There are no CO_2 or greenhouse gas emission standards applicable to these diesel generators.

10.7.2 BACT Control Technology Determinations.

Table B10-8 is a summary of CO_2 and/or greenhouse gas emission limits for similar emergency generators. The limits in Table B10-8 indicate CO_2 or GHG emission limits typically expressed as tons per year. These limits appear to all be based on the maximum output of the generator on an hourly basis, and operational limits of 100 to 500 hours per year.

TABLE B10-8. Greenhouse gas (GHG) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	432 ton/year
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	526.39 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		183 ton/year
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	526.39 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	878 ton/year
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	1,186 ton/year
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	788.5 ton/year
Hickory Run Energy Station	PA	04/23/13	7.8 mmBtu/hr	80.5 ton/year

10.7.3 STEP 1. Identify All Potential Control Technologies.

CO_2 emissions result from the oxidation of carbon in the fuel. When combusting fuel, this reaction is responsible for much of the heat released in diesel engines and is therefore unavoidable. There are five potential control options for reducing CO_2 emissions from these diesel generators:

1. **The use of low carbon containing or lower emitting primary fuels,**
2. **The use of energy efficient processes and technologies,**
3. **Good combustion, operating, and maintenance practices,**
4. **Low annual capacity factor (applicable to emergency generators),**
5. **Carbon capture and sequestration (CCS) as a post combustion control system.**

10.7.4 STEP 2. Identify Technically Feasible Control Technologies.

The purpose of these generators is to provide a power source during emergencies when the electric grid may be down, during natural disasters, or when natural gas may be curtailed or interrupted and the combustion turbines are unavailable. Liquid fuels which can be stored on site are necessary to ensure that these critical emergency generators will start reliably. Because electricity and natural gas may not be available during these emergencies, natural gas and electricity are not technically feasible control technologies for these emergency generators. And gasoline engines are generally not as efficient as diesel engines and are not available in the large size necessary for these generators.

The use of energy efficient processes and technologies, and the use of good combustion, operating, and maintenance practices are both technically feasible control options. The proposed diesel engines are modern, efficient engines which minimize GHG emissions. The use of good combustion, operating, and maintenance practices will help ensure that the engines operate at or near their design efficiency.

Limiting the operation of any emissions unit will limit emissions. The majority of the operation of these generators will be for maintenance and readiness testing. Because these engines will be used primarily for emergency operation, limiting the operation of these gensets is technically feasible. Therefore, APS proposes to limit the operation of these generators to no more than 100 hours per year.

Chapter 6 of this control technology review includes a detailed discussion of carbon capture and sequestration (CCS). While carbon capture with an MEA absorption process may be technically feasible for combined-cycle gas turbines, it is not feasible for emergency RICE because the exhaust gas temperature is too high for the MEA process and because these engines operate infrequently. Therefore, CCS is also not a technically feasible control option for these emergency generators.

10.7.5 STEP 3. Rank the Technically Feasible Control Technologies.

The use of energy efficient processes and technologies, good combustion, operating, and maintenance practices, and low annual capacity factor are all technically feasible control options and are also proposed for these emergency generators.

10.7.6 STEP 4. Evaluate the Most Effective Controls.

APS proposes the use of energy efficient processes and technologies, good combustion, operating, and maintenance practices, and low annual capacity factor as BACT for these generators. The use of diesel generator sets manufactured to meet the Tier 2 standards will ensure the use of energy efficient processes. This is the highest level of control available for these generators. Therefore, further evaluation is unnecessary.

10.7.7 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of energy efficient processes and technologies, good combustion, operating, and maintenance practices, and a low annual capacity factor represents BACT for the control of GHG emissions from the proposed diesel generators. APS proposes the following limits as BACT for the control of GHG emissions from the emergency generators:

1. Carbon dioxide (CO_2) emissions from each diesel engine generator may not exceed 987.8 tons per year.
2. The operation of each generator may not exceed 500 hours per year.

Chapter 11. Diesel Fuel Oil Storage Tank Control Technology Review.

The Project will also include two (2) 10,000 gallon diesel fuel oil storage tanks. Based on the operational limits for the diesel generators of 500 hours per year as proposed in this application and a maximum diesel engine fuel consumption rate of 175 gallons per hour, the maximum annual throughput for each tank would be 87,500 gallons per year. Potential VOC emissions based on the U.S. EPA's TANKS program, Version 4.0.9d (which is based on the equations from AP-42, Section 7.1, Organic Storage Tanks), are 4.45 pounds per year for each tank, or total VOC emissions of 0.005 tons per year for both tanks combined. The emissions are summarized in Table B11-1. Note that under normal generator operation which would be less than 500 hours per year, the working losses would be very small, and the emissions would approach the breathing losses only which are less than 2 pounds per year.

TABLE B11-1. TANKS 4.0.9d annual emissions summary report, individual tank emission totals.

Components	Tank Losses (lbs)		
	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	2.85	1.60	4.45

Based on the NSR applicability analysis in Chapter 4 of the construction permit application, the Project will not be subject to PSD BACT nor NANSR LAER requirements. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of VOC emissions. Therefore, the following BACT analysis is being conducted to comply with Maricopa County Rule 241, Section 301.1.

The proposed diesel fuel oil storage tanks will be equipped with submerged fill pipes which will reduce working losses. Because the vapor pressure of diesel fuel oil is very low, losses from these tanks will be very small. At a cost effectiveness threshold of $10,000 per ton of VOCs controlled ($5.00 per pound), controls which cost more than $25 per tank per year would not be cost effective. Based on the very low potential VOC emissions there are no control technologies available for these tanks which would be economically feasible to reduce the already extremely low level of emissions.

Based on this analysis, APS has concluded that the use of diesel fuel oil storage tanks with submerged fill pipes represents the best available control technology (BACT) for the control of VOC emissions from the proposed diesel fuel oil storage tanks.

Chapter 12. SF_6 Insulated Electrical Equipment Control Technology Review.

The Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21 includes sulfur hexafluoride (SF_6) as a regulated GHG substance or pollutant. The proposed circuit breakers which will be installed with the new LMS 100 GTs and emergency generators 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, since if too much gas leaked out, the equipment may not operate correctly and could become unsafe. The proposed circuit breakers will have a low pressure alarm and a low pressure lockout system. The alarm will alert personnel of leakage and the lockout would prevent operation of the breaker due to a lack of spark suppression from the SF_6 gas. 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 also the International Electrotechnical Commission (IEC) maximum leak rate standard. Table B12-1 summarizes the potential SF_6 emissions for the planned equipment. Note that the potential CO_2e emissions from circuit breaker SF_6 emissions account for 0.01% of the project's total CO_2e emissions.

TABLE B12-1. Potential fugitive sulfur hexafluoride (SF_6) emissions from the planned SF_6 insulated 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 Emissions, ton CO_2e /year
230 kV	9	135	0.50%	0.0030	23,900	72.6
69 kV	11	75	0.50%	0.0021	23,900	49.3
13.8 kV	5	35	0.50%	0.0004	23,900	10.5
TOTAL FUGITIVE EMISSIONS				**0.0046**	**23,900**	**132.3**

Footnotes

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

12.1 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.

12.2 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.

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 SF6 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.

12.3 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.

12.4 STEP 4. Evaluate the Most Effective Controls.

APS proposes 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. This is the highest level of control available for the control of SF_6 emissions. Therefore, further evaluation is unnecessary.

12.5 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 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 annual leakage rate of 0.5% by weight.

Chapter 13. Natural Gas Piping Systems 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 therefore result in small amounts of fugitive natural gas emissions. Since natural gas consists of from 70 to almost 100% methane, leaks in the natural gas piping at the Ocotillo plant can result in small amounts of methane emissions.

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 B13-1 summarizes the estimated fugitive methane emissions which are expected to result from a properly operated and maintained natural gas piping system at the Ocotillo Power Plant. Note that these estimated fugitive emissions are less than 0.01% of the total potential GHG emissions from the proposed Project.

TABLE B13-1. Potential fugitive methane emissions from the natural gas piping systems and the equivalent GHG emissions.

Component Type	Component Count	Emission Factor scf / hour / component	Specific Volume scf / lb CH_4	Methane (CH_4) ton/year	CO_2e Factor[4]	Potential Emissions ton CO_2e /year
Valves	150	0.123	24.1	3.35	25	83.9
Connectors	125	0.017	24.1	0.39	25	9.7
Relief Valves	10	0.196	24.1	0.36	25	8.9
TOTAL PIPELINE FUGITIVE EMISSIONS				**4.10**	**25**	**102.4**

Footnotes

1. The emission factors are from 40 CFR Part 98, Table W-1A for onshore natural gas production, Western U.S.
2. The CO_2e factor is from 40 CFR 98, Subpart A, Table A-1.
3. The specific volume of methane at 68 ^oF 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.
4. Methane emissions are based on the worst-case assumption that the natural gas is 100% methane by volume.

13.1 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.

13.2 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 never-the-less do exist so that this technology does not eliminate fugitive emissions. Leakless technology components are used for highly toxic and hazardous materials. However, leakless technology components 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. 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 Ocotillo 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.

13.3 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.

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 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 cooling 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. 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.

13.4 STEP 4. Evaluate the Most Effective Controls.

APS proposes the use of audio/visual/olfactory (AVO) monitoring as 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, further evaluation is unnecessary.

13.5 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of audio/visual/olfactory (AVO) monitoring represents 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 natural gas piping components.
2. AVO monitoring shall be performed in accordance with a written monitoring program.

Appendix C.

Operational and Emissions Data for the General Electric Model LMS100 Simple Cycle Gas Turbines

Performance data for the General Electric Model LMS100® simple cycle gas turbines at 24 possible load and ambient air conditions.

Case #	100	105	110	115	116	121	126	131	228	233	238	243	180	185	190	195	196	201	206	211	212	217	222	227	MAX
Dry Bulb Temperature, °F	20	20	20	20	41	41	41	41	73	73	73	73	105	105	105	105	113	113	113	113	120	120	120	120	120
Wet Bulb Temperature, °F	17	17	17	17	34	34	34	34	57	57	57	57	71	71	71	71	75	75	75	75	78	78	78	78	78
Relative Humidity, %	60	60	60	60	51	51	51	51	37	37	37	37	19	19	19	19	17	17	17	17	15	15	15	15	60
Engine Inlet																									
Conditioning	HEAT	HEAT	HEAT	HEAT	NONE	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	
Tons Chill or kBtu/hr Heat	4,203	3,753	3,428	2,868					1,063				2,598				2,605				2,609				4,203
Partial Load, %	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	
Gross Generation, MW	111.3	83.5	55.7	27.8	111.0	83.3	55.5	27.8	109.8	82.3	54.9	27.4	109.9	82.4	54.9	27.5	108.1	81.1	54.0	27.0	106.8	80.1	53.4	26.7	111.3
Gross Generation, kW	111,334	83,505	55,668	27,835	111,000	83,253	55,505	27,752	109,790	82,341	54,892	27,448	109,856	82,392	54,925	27,465	108,071	81,055	54,033	27,018	106,817	80,110	53,403	26,702	111,334
Est. Btu/kW-hr, LHV	7,815	8,215	9,305	12,053	7,831	8,241	9,327	12,089	7,843	8,309	9,389	12,183	7,847	8,387	9,418	12,216	7,878	8,436	9,476	12,303	7,901	8,475	9,520	12,366	12,366
Guar. Btu/kW-hr, LHV	7,854	--	--	--	7,870	--	--	--	7,883	--	--	--	7,886	--	--	--	7,918	--	--	--	7,941	--	--	--	7,941
Est. Btu/kW-hr, HHV	8,667	9,111	10,320	13,367	8,684	9,140	10,344	13,407	8,698	9,215	10,413	13,511	8,702	9,301	10,445	13,547	8,737	9,356	10,509	13,644	8,763	9,398	10,558	13,714	13,714
Guar. Btu/kW-hr, HHV	8,711				8,728				8,742				8,746				8,781				8,807				8,807
Fuel and Water Flow																									
MMBtu/hr, LHV	870	686	518	336	869	686	518	336	861	684	515	334	862	691	517	336	851	684	512	332	844	679	508	330	870
MMBtu/hr, HHV	**965**	**761**	**574**	**372**	**964**	**761**	**574**	**372**	**955**	**759**	**572**	**371**	**956**	**766**	**574**	**372**	**944**	**758**	**568**	**369**	**936**	**753**	**564**	**366**	**965**
Fuel (Nat Gas) Flow, lb/hr	42,250	33,312	25,152	16,291	42,209	33,320	25,139	16,292	41,814	33,225	25,028	16,237	41,859	33,553	25,122	16,291	41,346	33,203	24,864	16,141	40,985	32,966	24,690	16,035	**42,250**
Water Flow, lb/hr	27,619	18,990	12,516	6,383	27,568	19,012	12,496	6,371	25,627	17,902	11,670	5,782	25,401	17,433	11,074	5,315	24,415	16,950	10,621	5,014	23,795	16,731	10,379	4,852	**27,619**
																									0
Exhaust Parameters																									**0**
Temperature, °F	771	750	794	854	784	766	807	868	787	782	817	878	786	806	824	883	790	811	828	886	793	817	833	890	**890**
Temperature, °R	311	291	334	394	324	306	347	409	327	322	357	418	327	346	364	423	330	352	368	426	334	358	373	431	**431**
Exhaust Flow, lb/hr	1,815,959	1,578,099	1,260,994	893,661	1,796,111	1,556,233	1,244,993	882,351	1,779,526	1,525,792	1,227,049	870,908	1,780,587	1,498,024	1,219,368	866,800	1,759,546	1,478,851	1,205,746	858,761	1,743,421	1,463,464	1,194,151	851,480	1,815,959
Exhaust Molecular Weight	28.192	28.289	28.349	28.431	28.161	28.256	28.317	28.400	28.123	28.196	28.261	28.345	28.122	28.142	28.220	28.306	28.104	28.132	28.205	28.291	28.090	28.124	28.193	28.280	28.192
Exhaust Flowrate, ACFM	1,007,089	857,300	708,061	524,335	1,007,079	857,129	707,390	524,063	1,001,693	853,480	703,986	521,984	1,001,927	855,394	704,269	522,221	993,415	848,613	699,061	518,766	987,641	844,047	695,430	516,219	1,007,089
Estimated Stack Emissions with Exhaust System in GE Scope of Supply and the Notes Below																									
NO_x ppmvd Ref 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	**2.5**
NO_x, lb/hr	9.3	7.3	5.5	3.6	9.3	7.3	5.5	3.6	9.2	7.3	5.5	3.6	9.2	7.4	5.5	3.6	9.1	7.3	5.5	3.5	9.0	7.2	5.4	3.5	**9.3**
NH_3 Slip, ppmdv, 15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	**5.0**
NH_3 Slip, lb/hr	6.9	5.4	4.1	2.6	6.9	5.4	4.1	2.6	6.8	5.4	4.1	2.6	6.8	5.4	4.1	2.6	6.7	5.4	4.0	2.6	6.7	5.4	4.0	2.6	**6.9**
CO ppmvd Ref 15% O2	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	**6.0**
CO, lb/hr	13.5	10.7	8.1	5.2	13.5	10.7	8.1	5.2	13.4	10.6	8.0	5.2	13.4	10.7	8.0	5.2	13.2	10.6	8.0	5.2	13.1	10.6	7.9	5.1	**13.5**
VOC ppmdv, 15% O2, as C	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	**2.0**
VOC, lb/hr (MW = 14.36)	2.6	2.0	1.5	1.0	2.6	2.0	1.5	1.0	2.6	2.0	1.5	1.0	2.6	2.1	1.5	1.0	2.5	2.0	1.5	1.0	2.5	2.0	1.5	1.0	**2.6**
PM_{10}, lbs/hr	5.4				5.4				5.4				5.4				5.4				5.4				**5.4**
CO_2, weight %, wet basis	6.2572	5.6816	5.3711	4.9124	6.3196	5.7619	5.4365	4.9747	6.3187	5.8590	5.4908	5.0225	6.3217	6.0251	5.5456	5.0625	6.3188	6.0394	5.5505	5.0627	6.3215	6.0593	5.5650	5.0724	6.3217
CO_2, lb/hr	113,628	89,661	67,729	43,900	113,507	89,669	67,684	43,894	112,443	89,396	67,375	43,741	112,563	90,257	67,621	43,882	111,182	89,314	66,925	43,476	110,210	88,676	66,455	43,190	113,628
CO_2, lb/mmBtu	117.8	117.9	117.9	118.0	117.8	117.8	117.9	118.0	117.7	117.8	117.9	117.9	117.7	117.8	117.9	117.9	117.8	117.8	117.9	117.9	117.7	117.8	117.9	117.9	118.0
CO_2, lb/MWhr (gross)	1,021	1,074	1,217	1,577	1,023	1,077	1,219	1,582	1,024	1,086	1,227	1,594	1,025	1,095	1,231	1,598	1,029	1,102	1,239	1,609	1,032	1,107	1,244	1,617	1,617
CO_2, lb/MWhr (gross, deg)	1,082	1,138	1,290	1,672	1,084	1,142	1,293	1,677	1,086	1,151	1,301	1,689	1,086	1,161	1,305	1,694	1,091	1,168	1,313	1,706	1,094	1,173	1,319	1,715	1,715

Footnotes

1. Performance data is from General Electric, Engine LMS-100PA, generator BDAX 82-445ERH Tewac 60Hz, 13.8kV, 0.85PF (EffCurve#: 32398; CapCurve#: 34089). Data run conducted on 5/28/2014.
2. All data for elevation of 1,178 ft and pressure of 14.081 (0.95815 atm).
3. Performance and emissions data are based on the following natural gas fuel values: Btu/lb, LHV 20,593 Btu/lb, HHV 22,838 Ratio, HHV to LHV 1.109
4. CO_2 emissions are calculated from GE performance data and were not provided by GE. Emission rates expressed as "deg" are based on a 6% degradation in engine efficiency due to normal operation of the engine.

Appendix D.

Acid Rain Permit Application.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ **New** X **Revised** ☐ **for ARP permit renewal**

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name: Ocotillo Power Plant	State: Arizona	Plant Code: 00116

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
GT3	Yes
GT4	Yes
GT5	Yes
GT6	Yes
GT7	Yes

Facility (Source) Name: Ocotillo Power Plant

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the

submission of a new certificate of representation changing the designated representative;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

Facility (Source) Name: Ocotillo Power Plant

STEP 3, Cont'd.

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

Effect on Other Authorities, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements
under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name: Dennis Irvin	
Signature Dennis J Irvin	Date: 9/28/2015

Appendix E.

Detailed Baseline Emission Data for the Ocotillo Steam Generating Units

Appendix E.

Baseline actual emissions for the Ocotillo Power Plant.

TABLE E-1. Total baseline actual emissions for the Ocotillo Power Plant Steamer Units 1 and 2. All emissions are expressed in tons per year, based on a 24-month rolling average.

Year	Month	Carbon Monoxide CO	Nitrogen Oxides NOx	Particulate Matter PM, PM_{10}, $PM_{2.5}$	Sulfur Dioxide SO_2	Organic Cmpds VOC	Sulfuric Acid Mist H_2SO4	Lead Pb	Carbon Dioxide CO_2	Greenhouse Gases GHG	Heat Input mmBtu
2010	January	11.1	66.7	3.5	0.3	2.6	0.0003	0.0002	56,144	56,198	944,718
	February	10.8	65.3	3.4	0.3	2.5	0.0003	0.0002	54,620	54,673	919,089
	March	10.8	65.3	3.4	0.3	2.5	0.0003	0.0002	54,620	54,673	919,089
	April	10.8	65.1	3.4	0.3	2.5	0.0003	0.0002	54,313	54,365	913,926
	May	10.6	64.1	3.3	0.3	2.5	0.0003	0.0002	53,347	53,398	897,663
	June	9.6	58.5	3.0	0.2	2.2	0.0002	0.0002	48,566	48,613	817,225
	July	9.2	56.5	2.9	0.2	2.1	0.0002	0.0002	46,331	46,376	779,610
	August	9.5	59.3	3.0	0.2	2.2	0.0002	0.0002	47,944	47,990	806,743
	September	9.7	63.6	3.1	0.2	2.3	0.0002	0.0002	49,131	49,178	826,707
	October	9.9	64.8	3.1	0.3	2.3	0.0003	0.0002	50,125	50,173	843,444
	November	9.9	64.5	3.1	0.2	2.3	0.0002	0.0002	49,821	49,869	838,338
	December	9.9	64.5	3.1	0.2	2.3	0.0002	0.0002	49,817	49,865	838,263
2011	January	9.9	64.6	3.1	0.3	2.3	0.0003	0.0002	49,950	49,998	840,503
	February	10.0	65.4	3.2	0.3	2.3	0.0003	0.0002	50,744	50,793	853,867
	March	10.1	65.4	3.2	0.3	2.4	0.0003	0.0002	50,822	50,871	855,179
	April	10.1	65.5	3.2	0.3	2.4	0.0003	0.0002	50,860	50,909	855,817
	May	9.1	58.9	2.9	0.2	2.1	0.0002	0.0002	46,012	46,056	774,231
	June	9.2	60.2	2.9	0.2	2.2	0.0002	0.0002	46,710	46,755	785,975
	July	9.0	56.8	2.8	0.2	2.1	0.0002	0.0002	45,263	45,307	761,618
	August	9.8	58.5	3.1	0.2	2.3	0.0002	0.0002	49,506	49,554	833,019
	September	9.8	57.3	3.1	0.2	2.3	0.0002	0.0002	49,667	49,715	835,740
	October	10.9	63.4	3.4	0.3	2.5	0.0003	0.0002	54,950	55,003	924,647
	November	10.8	63.0	3.4	0.3	2.5	0.0003	0.0002	54,683	54,736	920,150
	December	10.9	63.3	3.5	0.3	2.6	0.0003	0.0002	55,251	55,304	929,693

TABLE E-1. Total baseline actual emissions for the Ocotillo Power Plant Steamer Units 1 and 2. All emissions are expressed in tons per year, based on a 24-month rolling average.

Year	Month	Carbon Monoxide CO	Nitrogen Oxides NOx	Particulate Matter PM, PM_{10}, $PM_{2.5}$	Sulfur Dioxide SO_2	Organic Cmpds VOC	Sulfuric Acid Mist H_2SO4	Lead Pb	Carbon Dioxide CO_2	Greenhouse Gases GHG	Heat Input mmBtu
2012	January	10.9	63.3	3.5	0.3	2.6	0.0003	0.0002	55,217	55,270	929,125
	February	10.9	63.3	3.5	0.3	2.6	0.0003	0.0002	55,209	55,262	928,989
	March	11.0	63.9	3.5	0.3	2.6	0.0003	0.0002	55,783	55,836	938,636
	April	11.7	67.9	3.7	0.3	2.7	0.0003	0.0002	59,047	59,104	993,554
	May	12.3	71.6	3.9	0.3	2.9	0.0003	0.0003	62,298	62,358	1,048,243
	June	13.5	79.0	4.3	0.3	3.1	0.0003	0.0003	67,969	68,035	1,143,673
	July	13.3	78.7	4.2	0.3	3.1	0.0003	0.0003	67,428	67,493	1,134,577
	August	13.5	80.2	4.3	0.3	3.2	0.0003	0.0003	68,261	68,326	1,148,612
	September	13.0	74.3	4.1	0.3	3.0	0.0003	0.0003	65,709	65,773	1,105,678
	October	12.3	70.3	3.9	0.3	2.9	0.0003	0.0003	62,316	62,376	1,048,575
	November	12.3	70.3	3.9	0.3	2.9	0.0003	0.0003	62,251	62,311	1,047,480
	December	12.4	70.9	3.9	0.3	2.9	0.0003	0.0003	62,759	62,819	1,056,027
2013	January	12.9	73.4	4.1	0.3	3.0	0.0003	0.0003	65,195	65,257	1,097,011
	February	12.8	72.8	4.1	0.3	3.0	0.0003	0.0003	64,634	64,697	1,087,583
	March	12.8	72.8	4.0	0.3	3.0	0.0003	0.0003	64,587	64,650	1,086,793
	April	13.0	74.0	4.1	0.3	3.0	0.0003	0.0003	65,797	65,860	1,107,148
	May	13.4	76.3	4.2	0.3	3.1	0.0003	0.0003	67,632	67,697	1,138,022
	June	14.3	82.7	4.5	0.4	3.3	0.0004	0.0003	72,200	72,269	1,214,879
	July	15.7	91.7	5.0	0.4	3.7	0.0004	0.0003	79,348	79,425	1,335,177
	August	15.0	88.8	4.7	0.4	3.5	0.0004	0.0003	75,534	75,608	1,270,997
	September	15.0	89.3	4.7	0.4	3.5	0.0004	0.0003	75,669	75,744	1,273,263
	October	13.8	82.4	4.4	0.4	3.2	0.0004	0.0003	69,815	69,885	1,174,765
	November	14.1	83.9	4.5	0.4	3.3	0.0004	0.0003	71,115	71,185	1,196,628
	December	14.3	85.0	4.5	0.4	3.3	0.0004	0.0003	72,094	72,166	1,213,108
2014	January	14.5	85.6	4.6	0.4	3.4	0.0004	0.0003	73,394	73,467	1,234,977
	February	14.6	85.9	4.6	0.4	3.4	0.0004	0.0003	73,972	74,045	1,244,701

TABLE E-2. Baseline actual carbon monoxide (CO) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Carbon Monoxide (CO) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	30,413			0.0235	0.36		
	Feb	25,172			0.0235	0.30		
	Mar	-				-		
	Apr	9,629			0.0235	0.11		
	May	18,023			0.0235	0.21		
	Jun	87,522			0.0235	1.03		
	Jul	93,208			0.0235	1.10		
	Aug	114,585			0.0235	1.35		
	Sep	43,332			0.0235	0.51		
	Oct	26,137			0.0235	0.31		
	Nov	402			0.0235	0.00		
	Dec	151			0.0235	0.00		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	-				-		
	May	-				-		
	Jun	10,853			0.0235	0.13		
	Jul	159,569			0.0235	1.88		
	Aug	91,118			0.0235	1.07		
	Sep	47,848			0.0235	0.56		
	Oct	12,846			0.0235	0.15		
	Nov	1,000			0.0235	0.01		
	Dec	3,394	775,201	387,601	0.0235	0.04	9.12	4.56
2010	Jan	686	745,474	372,737	0.0235	0.01	8.77	4.39
	Feb	133	720,435	360,217	0.0235	0.00	8.48	4.24
	Mar	-	720,435	360,217		-	8.48	4.24
	Apr	-	710,806	355,403		-	8.36	4.18
	May	-	692,783	346,391		-	8.15	4.08
	Jun	9,634	614,895	307,447	0.0235	0.11	7.23	3.62
	Jul	64,030	585,716	292,858	0.0235	0.75	6.89	3.45
	Aug	103,982	575,114	287,557	0.0235	1.22	6.77	3.38
	Sep	92,810	624,592	312,296	0.0235	1.09	7.35	3.67
	Oct	68,919	667,375	333,687	0.0235	0.81	7.85	3.93
	Nov	144	667,117	333,558	0.0235	0.00	7.85	3.92
	Dec	-	666,966	333,483		-	7.85	3.92

TABLE E-2. Baseline actual carbon monoxide (CO) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Carbon Monoxide (CO) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	-	666,966	333,483		-	7.85	3.92
	Feb	6,507	673,473	336,737	0.0235	0.08	7.92	3.96
	Mar	2,625	676,098	338,049	0.0235	0.03	7.95	3.98
	Apr	141	676,239	338,120	0.0235	0.00	7.96	3.98
	May	-	676,239	338,120		-	7.96	3.98
	Jun	41,581	706,968	353,484	0.0235	0.49	8.32	4.16
	Jul	116,450	663,849	331,924	0.0235	1.37	7.81	3.90
	Aug	214,780	787,510	393,755	0.0235	2.53	9.26	4.63
	Sep	70,041	809,703	404,851	0.0235	0.82	9.53	4.76
	Oct	92,177	889,034	444,517	0.0235	1.08	10.46	5.23
	Nov	699	888,732	444,366	0.0235	0.01	10.46	5.23
	Dec	20,646	905,985	452,993	0.0235	0.24	10.66	5.33
2012	Jan	-	905,299	452,650		-	10.65	5.33
	Feb	-	905,166	452,583		-	10.65	5.32
	Mar	17,911	923,078	461,539	0.0235	0.21	10.86	5.43
	Apr	24,902	947,979	473,990	0.0235	0.29	11.15	5.58
	May	58,498	1,006,477	503,238	0.0235	0.69	11.84	5.92
	Jun	115,484	1,112,327	556,164	0.0235	1.36	13.09	6.54
	Jul	61,112	1,109,410	554,705	0.0235	0.72	13.05	6.53
	Aug	155,558	1,160,986	580,493	0.0235	1.83	13.66	6.83
	Sep	61,083	1,129,259	564,629	0.0235	0.72	13.29	6.64
	Oct	25,256	1,085,595	542,798	0.0235	0.30	12.77	6.39
	Nov	132	1,085,583	542,792	0.0235	0.00	12.77	6.39
	Dec	9,800	1,095,383	547,691	0.0235	0.12	12.89	6.44
2013	Jan	58,429	1,153,812	576,906	0.0235	0.69	13.57	6.79
	Feb	4,345	1,151,650	575,825	0.0235	0.05	13.55	6.77
	Mar	1,045	1,150,070	575,035	0.0235	0.01	13.53	6.77
	Apr	12,952	1,162,881	581,440	0.0235	0.15	13.68	6.84
	May	38,778	1,201,659	600,830	0.0235	0.46	14.14	7.07
	Jun	132,850	1,292,928	646,464	0.0235	1.56	15.21	7.61
	July	153,657	1,330,134	665,067	0.0235	1.81	15.65	7.82
	August	143,629	1,258,983	629,491	0.0235	1.69	14.81	7.41
	September	70,759	1,259,701	629,850	0.0235	0.83	14.82	7.41
	October	241	1,167,765	583,882	0.0235	0.00	13.74	6.87
	November	17,978	1,185,044	592,522	0.0235	0.21	13.94	6.97
	December	18,106	1,182,503	591,252	0.0235	0.21	13.91	6.96
2014	January	31,521	1,214,024	607,012	0.0235	0.37	14.28	7.14
	February	5,698	1,219,722	609,861	0.0235	0.07	14.35	7.17

TABLE E-3. Baseline actual carbon monoxide (CO) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Carbon Monoxide (CO) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	15,421			0.0235	0.18		
	Feb	26,358			0.0235	0.31		
	Mar	-				-		
	Apr	1,896			0.0235	0.02		
	May	14,503			0.0235	0.17		
	Jun	89,587			0.0235	1.05		
	Jul	90,637			0.0235	1.07		
	Aug	79,336			0.0235	0.93		
	Sep	76,799			0.0235	0.90		
	Oct	80,639			0.0235	0.95		
	Nov	12,131			0.0235	0.14		
	Dec	-				-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			0.0235	0.01		
	May	163,171			0.0235	1.92		
	Jun	61,573			0.0235	0.72		
	Jul	169,916			0.0235	2.00		
	Aug	161,270			0.0235	1.90		
	Sep	81,486			0.0235	0.96		
	Oct	13,265			0.0235	0.16		
	Nov	12,745			0.0235	0.15		
	Dec	7,705	1,158,934	579,467	0.0235	0.09	13.63	6.82
2010	Jan	450	1,143,962	571,981	0.0235	0.01	13.46	6.73
	Feb	138	1,117,742	558,871	0.0235	0.00	13.15	6.57
	Mar	-	1,117,742	558,871		-	13.15	6.57
	Apr	1,200	1,117,046	558,523	0.0235	0.01	13.14	6.57
	May	-	1,102,543	551,271		-	12.97	6.49
	Jun	6,599	1,019,554	509,777	0.0235	0.08	11.99	6.00
	Jul	44,585	973,503	486,751	0.0235	0.52	11.45	5.73
	Aug	144,204	1,038,371	519,186	0.0235	1.70	12.22	6.11
	Sep	67,249	1,028,822	514,411	0.0235	0.79	12.10	6.05
	Oct	71,331	1,019,513	509,757	0.0235	0.84	11.99	6.00
	Nov	2,177	1,009,559	504,780	0.0235	0.03	11.88	5.94
	Dec	-	1,009,559	504,780		-	11.88	5.94

TABLE E-3. Baseline actual carbon monoxide (CO) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Carbon Monoxide (CO) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,014,040	507,020	0.0235	0.05	11.93	5.96
	Feb	20,220	1,034,260	517,130	0.0235	0.24	12.17	6.08
	Mar	-	1,034,260	517,130		-	12.17	6.08
	Apr	1,630	1,035,394	517,697	0.0235	0.02	12.18	6.09
	May	-	872,223	436,112		-	10.26	5.13
	Jun	54,333	864,983	432,492	0.0235	0.64	10.18	5.09
	Jul	164,320	859,387	429,694	0.0235	1.93	10.11	5.06
	Aug	180,411	878,528	439,264	0.0235	2.12	10.34	5.17
	Sep	64,736	861,778	430,889	0.0235	0.76	10.14	5.07
	Oct	111,748	960,260	480,130	0.0235	1.31	11.30	5.65
	Nov	4,053	951,568	475,784	0.0235	0.05	11.19	5.60
	Dec	9,537	953,400	476,700	0.0235	0.11	11.22	5.61
2012	Jan	-	952,951	476,475		-	11.21	5.61
	Feb	-	952,812	476,406		-	11.21	5.60
	Mar	1,382	954,194	477,097	0.0235	0.02	11.23	5.61
	Apr	86,134	1,039,128	519,564	0.0235	1.01	12.23	6.11
	May	50,881	1,090,010	545,005	0.0235	0.60	12.82	6.41
	Jun	91,607	1,175,018	587,509	0.0235	1.08	13.82	6.91
	Jul	29,312	1,159,745	579,872	0.0235	0.34	13.64	6.82
	Aug	120,697	1,136,238	568,119	0.0235	1.42	13.37	6.68
	Sep	13,110	1,082,098	541,049	0.0235	0.15	12.73	6.37
	Oct	786	1,011,554	505,777	0.0235	0.01	11.90	5.95
	Nov	-	1,009,377	504,688		-	11.88	5.94
	Dec	7,294	1,016,671	508,336	0.0235	0.09	11.96	5.98
2013	Jan	28,020	1,040,210	520,105	0.0235	0.33	12.24	6.12
	Feb	3,526	1,023,516	511,758	0.0235	0.04	12.04	6.02
	Mar	-	1,023,516	511,758		-	12.04	6.02
	Apr	29,529	1,051,416	525,708	0.0235	0.35	12.37	6.18
	May	22,968	1,074,384	537,192	0.0235	0.27	12.64	6.32
	Jun	116,778	1,136,830	568,415	0.0235	1.37	13.37	6.69
	July	367,709	1,340,219	670,110	0.0235	4.33	15.77	7.88
	August	123,204	1,283,012	641,506	0.0235	1.45	15.09	7.55
	September	68,549	1,286,825	643,413	0.0235	0.81	15.14	7.57
	October	6,688	1,181,765	590,883	0.0235	0.08	13.90	6.95
	November	30,501	1,208,213	604,107	0.0235	0.36	14.21	7.11
	December	45,037	1,243,714	621,857	0.0235	0.53	14.63	7.32
2014	January	12,217	1,255,931	627,965	0.0235	0.14	14.78	7.39
	February	13,749	1,269,680	634,840	0.0235	0.16	14.94	7.47

TABLE E-4. Baseline actual carbon monoxide (CO) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input				Carbon Monoxide (CO) Emissions		
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	45,835			0.0235	0.54		
	Feb	51,530			0.0235	0.61		
	Mar	-				-		
	Apr	11,525			0.0235	0.14		
	May	32,526			0.0235	0.38		
	Jun	177,110			0.0235	2.08		
	Jul	183,845			0.0235	2.16		
	Aug	193,920			0.0235	2.28		
	Sep	120,131			0.0235	1.41		
	Oct	106,776			0.0235	1.26		
	Nov	12,533			0.0235	0.15		
	Dec	151			0.0235	0.00		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			0.0235	0.01		
	May	163,171			0.0235	1.92		
	Jun	72,425			0.0235	0.85		
	Jul	329,485			0.0235	3.88		
	Aug	252,389			0.0235	2.97		
	Sep	129,335			0.0235	1.52		
	Oct	26,112			0.0235	0.31		
	Nov	13,745			0.0235	0.16		
	Dec	11,098	1,934,135	967,068	0.0235	0.13	22.75	11.38
2010	Jan	1,136	1,889,436	944,718	0.0235	0.01	22.23	11.11
	Feb	271	1,838,177	919,089	0.0235	0.00	21.63	10.81
	Mar	-	1,838,177	919,089		-	21.63	10.81
	Apr	1,200	1,827,852	913,926	0.0235	0.01	21.50	10.75
	May	-	1,795,326	897,663		-	21.12	10.56
	Jun	16,233	1,634,449	817,225	0.0235	0.19	19.23	9.61
	Jul	108,615	1,559,219	779,610	0.0235	1.28	18.34	9.17
	Aug	248,186	1,613,485	806,743	0.0235	2.92	18.98	9.49
	Sep	160,059	1,653,413	826,707	0.0235	1.88	19.45	9.73
	Oct	140,250	1,686,888	843,444	0.0235	1.65	19.85	9.92
	Nov	2,321	1,676,676	838,338	0.0235	0.03	19.73	9.86
	Dec	-	1,676,525	838,263		-	19.72	9.86

TABLE E-4. Baseline actual carbon monoxide (CO) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input				Carbon Monoxide (CO) Emissions		
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,681,006	840,503	0.0235	0.05	19.78	9.89
	Feb	26,727	1,707,733	853,867	0.0235	0.31	20.09	10.05
	Mar	2,625	1,710,358	855,179	0.0235	0.03	20.12	10.06
	Apr	1,771	1,711,634	855,817	0.0235	0.02	20.14	10.07
	May	-	1,548,463	774,231		-	18.22	9.11
	Jun	95,913	1,571,951	785,975	0.0235	1.13	18.49	9.25
	Jul	280,770	1,523,236	761,618	0.0235	3.30	17.92	8.96
	Aug	395,192	1,666,039	833,019	0.0235	4.65	19.60	9.80
	Sep	134,776	1,671,480	835,740	0.0235	1.59	19.66	9.83
	Oct	203,925	1,849,294	924,647	0.0235	2.40	21.76	10.88
	Nov	4,752	1,840,301	920,150	0.0235	0.06	21.65	10.83
	Dec	30,183	1,859,385	929,693	0.0235	0.36	21.88	10.94
2012	Jan	-	1,858,250	929,125		-	21.86	10.93
	Feb	-	1,857,979	928,989		-	21.86	10.93
	Mar	19,293	1,877,272	938,636	0.0235	0.23	22.09	11.04
	Apr	111,035	1,987,108	993,554	0.0235	1.31	23.38	11.69
	May	109,379	2,096,487	1,048,243	0.0235	1.29	24.66	12.33
	Jun	207,092	2,287,345	1,143,673	0.0235	2.44	26.91	13.45
	Jul	90,424	2,269,154	1,134,577	0.0235	1.06	26.70	13.35
	Aug	276,255	2,297,224	1,148,612	0.0235	3.25	27.03	13.51
	Sep	74,193	2,211,357	1,105,678	0.0235	0.87	26.02	13.01
	Oct	26,042	2,097,149	1,048,575	0.0235	0.31	24.67	12.34
	Nov	132	2,094,960	1,047,480	0.0235	0.00	24.65	12.32
	Dec	17,094	2,112,054	1,056,027	0.0235	0.20	24.85	12.42
2013	Jan	86,449	2,194,022	1,097,011	0.0235	1.02	25.81	12.91
	Feb	7,871	2,175,166	1,087,583	0.0235	0.09	25.59	12.80
	Mar	1,045	2,173,586	1,086,793	0.0235	0.01	25.57	12.79
	Apr	42,481	2,214,297	1,107,148	0.0235	0.50	26.05	13.03
	May	61,747	2,276,043	1,138,022	0.0235	0.73	26.78	13.39
	Jun	249,628	2,429,758	1,214,879	0.0235	2.94	28.59	14.29
	July	521,366	2,670,354	1,335,177	0.0235	6.13	31.42	15.71
	August	266,833	2,541,994	1,270,997	0.0235	3.14	29.91	14.95
	September	139,308	2,546,526	1,273,263	0.0235	1.64	29.96	14.98
	October	6,929	2,349,530	1,174,765	0.0235	0.08	27.64	13.82
	November	48,479	2,393,257	1,196,628	0.0235	0.57	28.16	14.08
	December	63,143	2,426,217	1,213,108	0.0235	0.74	28.54	14.27
2014	January	43,738	2,469,955	1,234,977	0.0235	0.51	29.06	14.53
	February	19,447	2,489,402	1,244,701	0.0235	0.23	29.29	14.64

TABLE E-5. Baseline actual nitrogen oxides (NO_x) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Nitrogen Oxides (NO_x) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	30,413			0.11	1.7		
	Feb	25,172			0.09	1.1		
	Mar	-				-		
	Apr	9,629			0.09	0.4		
	May	18,023			0.12	1.1		
	Jun	87,522			0.14	5.9		
	Jul	93,208			0.10	4.8		
	Aug	114,585			0.09	5.3		
	Sep	43,332			0.09	2.0		
	Oct	26,137			0.09	1.2		
	Nov	402			0.07	0.0		
	Dec	151			0.04	0.0		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	-				-		
	May	-				-		
	Jun	10,853			0.09	0.5		
	Jul	159,569			0.12	9.5		
	Aug	91,118			0.14	6.4		
	Sep	47,848			0.10	2.5		
	Oct	12,846			0.14	0.9		
	Nov	1,000			0.04	0.0		
	Dec	3,394	775,201	387,601	0.09	0.1	43.5	21.8
2010	Jan	686	745,474	372,737	0.04	0.0	41.8	20.9
	Feb	133	720,435	360,217	0.03	0.0	40.7	20.4
	Mar	-	720,435	360,217		-	40.7	20.4
	Apr	-	710,806	355,403		-	40.3	20.1
	May	-	692,783	346,391		-	39.2	19.6
	Jun	9,634	614,895	307,447	0.06	0.3	33.6	16.8
	Jul	64,030	585,716	292,858	0.10	3.2	32.0	16.0
	Aug	103,982	575,114	287,557	0.11	5.7	32.4	16.2
	Sep	92,810	624,592	312,296	0.12	5.8	36.1	18.1
	Oct	68,919	667,375	333,687	0.14	4.7	39.6	19.8
	Nov	144	667,117	333,558	0.03	0.0	39.6	19.8
	Dec	-	666,966	333,483		-	39.6	19.8

TABLE E-5. Baseline actual nitrogen oxides (NO_x) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Nitrogen Oxides (NO_x) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	-	666,966	333,483		-	39.6	19.8
	Feb	6,507	673,473	336,737	0.09	0.3	39.9	19.9
	Mar	2,625	676,098	338,049	0.08	0.1	40.0	20.0
	Apr	141	676,239	338,120	0.04	0.0	40.0	20.0
	May	-	676,239	338,120		-	40.0	20.0
	Jun	41,581	706,968	353,484	0.14	2.9	42.4	21.2
	Jul	116,450	663,849	331,924	0.12	7.0	39.8	19.9
	Aug	214,780	787,510	393,755	0.12	13.2	46.6	23.3
	Sep	70,041	809,703	404,851	0.12	4.2	48.3	24.2
	Oct	92,177	889,034	444,517	0.13	6.1	53.5	26.8
	Nov	699	888,732	444,366	0.07	0.0	53.5	26.8
	Dec	20,646	905,985	452,993	0.08	0.9	54.2	27.1
2012	Jan	-	905,299	452,650		-	54.2	27.1
	Feb	-	905,166	452,583		-	54.2	27.1
	Mar	17,911	923,078	461,539	0.11	1.0	55.2	27.6
	Apr	24,902	947,979	473,990	0.13	1.6	56.9	28.4
	May	58,498	1,006,477	503,238	0.13	3.9	60.8	30.4
	Jun	115,484	1,112,327	556,164	0.15	8.6	69.1	34.6
	Jul	61,112	1,109,410	554,705	0.13	4.1	70.0	35.0
	Aug	155,558	1,160,986	580,493	0.13	10.3	74.7	37.3
	Sep	61,083	1,129,259	564,629	0.13	3.8	72.8	36.4
	Oct	25,256	1,085,595	542,798	0.14	1.8	69.9	34.9
	Nov	132	1,085,583	542,792	0.05	0.0	69.9	34.9
	Dec	9,800	1,095,383	547,691	0.14	0.7	70.5	35.3
2013	Jan	58,429	1,153,812	576,906	0.12	3.4	74.0	37.0
	Feb	4,345	1,151,650	575,825	0.10	0.2	73.9	36.9
	Mar	1,045	1,150,070	575,035	0.05	0.0	73.8	36.9
	Apr	12,952	1,162,881	581,440	0.12	0.8	74.6	37.3
	May	38,778	1,201,659	600,830	0.15	2.9	77.5	38.8
	Jun	132,850	1,292,928	646,464	0.15	10.1	84.8	42.4
	July	153,657	1,330,134	665,067	0.13	10.3	88.1	44.1
	August	143,629	1,258,983	629,491	0.15	10.6	85.6	42.8
	September	70,759	1,259,701	629,850	0.12	4.3	85.7	42.9
	October	241	1,167,765	583,882	0.06	0.0	79.7	39.8
	November	17,978	1,185,044	592,522	0.10	0.9	80.6	40.3
	December	18,106	1,182,503	591,252	0.06	0.6	80.2	40.1
2014	January	31,521	1,214,024	607,012	0.06	1.0	81.2	40.6
	February	5,698	1,219,722	609,861	0.06	0.2	81.4	40.7

Footnotes

NO_x emissions are measured by the continuous emissions monitoring systems (CEMS) installed under the Federal Acid Rain Program in 40 CFR Part 75.

TABLE E-6. Baseline actual nitrogen oxides (NO_x) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Nitrogen Oxides (NO_x) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	15,421			0.13	1.0		
	Feb	26,358			0.13	1.7		
	Mar	-				-		
	Apr	1,896			0.05	0.0		
	May	14,503			0.13	1.0		
	Jun	89,587			0.13	5.9		
	Jul	90,637			0.13	5.8		
	Aug	79,336			0.14	5.5		
	Sep	76,799			0.16	6.0		
	Oct	80,639			0.15	6.2		
	Nov	12,131			0.13	0.8		
	Dec	-				-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			0.04	0.0		
	May	163,171			0.16	13.2		
	Jun	61,573			0.13	4.0		
	Jul	169,916			0.17	14.7		
	Aug	161,270			0.19	15.7		
	Sep	81,486			0.21	8.6		
	Oct	13,265			0.16	1.1		
	Nov	12,745			0.18	1.2		
	Dec	7,705	1,158,934	579,467	0.12	0.4	92.5	46.3
2010	Jan	450	1,143,962	571,981	0.04	0.0	91.5	45.8
	Feb	138	1,117,742	558,871	0.03	0.0	89.9	44.9
	Mar	-	1,117,742	558,871		-	89.9	44.9
	Apr	1,200	1,117,046	558,523	0.05	0.0	89.9	44.9
	May	-	1,102,543	551,271		-	88.9	44.4
	Jun	6,599	1,019,554	509,777	0.12	0.4	83.4	41.7
	Jul	44,585	973,503	486,751	0.15	3.4	81.0	40.5
	Aug	144,204	1,038,371	519,186	0.15	10.8	86.3	43.2
	Sep	67,249	1,028,822	514,411	0.32	10.7	91.1	45.5
	Oct	71,331	1,019,513	509,757	0.14	5.1	90.0	45.0
	Nov	2,177	1,009,559	504,780	0.08	0.1	89.4	44.7
	Dec	-	1,009,559	504,780		-	89.4	44.7

TABLE E-6. Baseline actual nitrogen oxides (NO_x) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Nitrogen Oxides (NO_x) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,014,040	507,020	0.10	0.2	89.6	44.8
	Feb	20,220	1,034,260	517,130	0.12	1.3	90.8	45.4
	Mar	-	1,034,260	517,130		-	90.8	45.4
	Apr	1,630	1,035,394	517,697	0.12	0.1	90.9	45.5
	May	-	872,223	436,112		-	77.8	38.9
	Jun	54,333	864,983	432,492	0.15	4.2	77.9	39.0
	Jul	164,320	859,387	429,694	0.13	10.5	73.7	36.9
	Aug	180,411	878,528	439,264	0.14	12.3	70.3	35.1
	Sep	64,736	861,778	430,889	0.14	4.6	66.3	33.2
	Oct	111,748	960,260	480,130	0.14	8.1	73.4	36.7
	Nov	4,053	951,568	475,784	0.10	0.2	72.4	36.2
	Dec	9,537	953,400	476,700	0.10	0.5	72.4	36.2
2012	Jan	-	952,951	476,475		-	72.4	36.2
	Feb	-	952,812	476,406		-	72.4	36.2
	Mar	1,382	954,194	477,097	0.11	0.1	72.5	36.3
	Apr	86,134	1,039,128	519,564	0.15	6.4	78.9	39.4
	May	50,881	1,090,010	545,005	0.14	3.5	82.3	41.2
	Jun	91,607	1,175,018	587,509	0.15	6.9	88.9	44.4
	Jul	29,312	1,159,745	579,872	0.13	2.0	87.4	43.7
	Aug	120,697	1,136,238	568,119	0.15	9.1	85.8	42.9
	Sep	13,110	1,082,098	541,049	0.14	0.9	75.9	38.0
	Oct	786	1,011,554	505,777	0.05	0.0	70.8	35.4
	Nov	-	1,009,377	504,688		-	70.7	35.4
	Dec	7,294	1,016,671	508,336	0.14	0.5	71.2	35.6
2013	Jan	28,020	1,040,210	520,105	0.13	1.8	72.9	36.4
	Feb	3,526	1,023,516	511,758	0.11	0.2	71.8	35.9
	Mar	-	1,023,516	511,758		-	71.8	35.9
	Apr	29,529	1,051,416	525,708	0.11	1.6	73.3	36.7
	May	22,968	1,074,384	537,192	0.16	1.8	75.1	37.6
	Jun	116,778	1,136,830	568,415	0.17	9.7	80.6	40.3
	July	367,709	1,340,219	670,110	0.14	25.1	95.3	47.6
	August	123,204	1,283,012	641,506	0.15	9.1	92.1	46.0
	September	68,549	1,286,825	643,413	0.16	5.5	92.9	46.5
	October	6,688	1,181,765	590,883	0.11	0.4	85.2	42.6
	November	30,501	1,208,213	604,107	0.15	2.2	87.2	43.6
	December	45,037	1,243,714	621,857	0.13	3.0	89.7	44.9
2014	January	12,217	1,255,931	627,965	0.05	0.3	90.0	45.0
	February	13,749	1,269,680	634,840	0.05	0.3	90.4	45.2

Footnotes

NO_x emissions are measured by the continuous emissions monitoring systems (CEMS) installed under the Federal Acid Rain Program in 40 CFR Part 75.

TABLE E-7. Baseline actual nitrogen oxides (NO_x) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input				Nitrogen Oxides (NO_x) Emissions		
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	45,835			0.12	2.70		
	Feb	51,530			0.11	2.79		
	Mar	-				-		
	Apr	11,525			0.09	0.49		
	May	32,526			0.12	2.02		
	Jun	177,110			0.13	11.82		
	Jul	183,845			0.11	10.57		
	Aug	193,920			0.11	10.80		
	Sep	120,131			0.13	7.96		
	Oct	106,776			0.14	7.35		
	Nov	12,533			0.12	0.77		
	Dec	151			0.04	0.00		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			0.04	0.01		
	May	163,171			0.16	13.17		
	Jun	72,425			0.12	4.48		
	Jul	329,485			0.15	24.27		
	Aug	252,389			0.17	22.08		
	Sep	129,335			0.17	11.01		
	Oct	26,112			0.15	1.97		
	Nov	13,745			0.17	1.18		
	Dec	11,098	1,934,135	967,068	0.11	0.60	136.06	68.03
2010	Jan	1,136	1,889,436	944,718	0.04	0.02	133.39	66.69
	Feb	271	1,838,177	919,089	0.03	0.00	130.60	65.30
	Mar	-	1,838,177	919,089		-	130.60	65.30
	Apr	1,200	1,827,852	913,926	0.05	0.03	130.14	65.07
	May	-	1,795,326	897,663		-	128.12	64.06
	Jun	16,233	1,634,449	817,225	0.09	0.69	116.99	58.50
	Jul	108,615	1,559,219	779,610	0.12	6.61	113.04	56.52
	Aug	248,186	1,613,485	806,743	0.13	16.42	118.66	59.33
	Sep	160,059	1,653,413	826,707	0.21	16.47	127.17	63.59
	Oct	140,250	1,686,888	843,444	0.14	9.79	129.61	64.80
	Nov	2,321	1,676,676	838,338	0.08	0.09	128.92	64.46
	Dec	-	1,676,525	838,263		-	128.92	64.46

TABLE E-7. Baseline actual nitrogen oxides (NO_x) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input				Nitrogen Oxides (NO_x) Emissions		
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,681,006	840,503	0.10	0.22	129.14	64.57
	Feb	26,727	1,707,733	853,867	0.12	1.57	130.71	65.36
	Mar	2,625	1,710,358	855,179	0.08	0.10	130.81	65.41
	Apr	1,771	1,711,634	855,817	0.11	0.10	130.90	65.45
	May	-	1,548,463	774,231		-	117.73	58.87
	Jun	95,913	1,571,951	785,975	0.15	7.05	120.30	60.15
	Jul	280,770	1,523,236	761,618	0.12	17.49	113.53	56.76
	Aug	395,192	1,666,039	833,019	0.13	25.46	116.91	58.45
	Sep	134,776	1,671,480	835,740	0.13	8.78	114.67	57.34
	Oct	203,925	1,849,294	924,647	0.14	14.16	126.86	63.43
	Nov	4,752	1,840,301	920,150	0.10	0.24	125.91	62.96
	Dec	30,183	1,859,385	929,693	0.09	1.36	126.68	63.34
2012	Jan	-	1,858,250	929,125		-	126.65	63.33
	Feb	-	1,857,979	928,989		-	126.65	63.32
	Mar	19,293	1,877,272	938,636	0.11	1.08	127.73	63.86
	Apr	111,035	1,987,108	993,554	0.14	8.04	135.74	67.87
	May	109,379	2,096,487	1,048,243	0.14	7.40	143.14	71.57
	Jun	207,092	2,287,345	1,143,673	0.15	15.57	158.01	79.01
	Jul	90,424	2,269,154	1,134,577	0.13	6.06	157.46	78.73
	Aug	276,255	2,297,224	1,148,612	0.14	19.39	160.43	80.21
	Sep	74,193	2,211,357	1,105,678	0.13	4.73	148.69	74.34
	Oct	26,042	2,097,149	1,048,575	0.14	1.78	140.68	70.34
	Nov	132	2,094,960	1,047,480	0.05	0.00	140.59	70.30
	Dec	17,094	2,112,054	1,056,027	0.14	1.20	141.79	70.90
2013	Jan	86,449	2,194,022	1,097,011	0.12	5.26	146.84	73.42
	Feb	7,871	2,175,166	1,087,583	0.10	0.40	145.67	72.83
	Mar	1,045	2,173,586	1,086,793	0.05	0.03	145.59	72.80
	Apr	42,481	2,214,297	1,107,148	0.11	2.43	147.93	73.96
	May	61,747	2,276,043	1,138,022	0.15	4.73	152.66	76.33
	Jun	249,628	2,429,758	1,214,879	0.16	19.82	165.43	82.71
	July	521,366	2,670,354	1,335,177	0.14	35.46	183.40	91.70
	August	266,833	2,541,994	1,270,997	0.15	19.70	177.63	88.82
	September	139,308	2,546,526	1,273,263	0.14	9.80	178.65	89.33
	October	6,929	2,349,530	1,174,765	0.10	0.36	164.85	82.43
	November	48,479	2,393,257	1,196,628	0.13	3.13	167.75	83.88
	December	63,143	2,426,217	1,213,108	0.11	3.56	169.95	84.97
2014	January	43,738	2,469,955	1,234,977	0.06	1.27	171.22	85.61
	February	19,447	2,489,402	1,244,701	0.05	0.52	171.74	85.87

Footnotes

NO_x emissions are measured by the continuous emissions monitoring systems (CEMS) installed under the Federal Acid Rain Program in 40 CFR Part 75.

TABLE E-8. Baseline actual particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			PM, PM_{10}, and $PM_{2.5}$ Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	30,413			0.0075	0.113		
	Feb	25,172			0.0075	0.094		
	Mar	-				-		
	Apr	9,629			0.0075	0.036		
	May	18,023			0.0075	0.067		
	Jun	87,522			0.0075	0.326		
	Jul	93,208			0.0075	0.347		
	Aug	114,585			0.0075	0.427		
	Sep	43,332			0.0075	0.161		
	Oct	26,137			0.0075	0.097		
	Nov	402			0.0075	0.001		
	Dec	151			0.0075	0.001		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	-				-		
	May	-				-		
	Jun	10,853			0.0075	0.040		
	Jul	159,569			0.0075	0.594		
	Aug	91,118			0.0075	0.339		
	Sep	47,848			0.0075	0.178		
	Oct	12,846			0.0075	0.048		
	Nov	1,000			0.0075	0.004		
	Dec	3,394	775,201	387,601	0.0075	0.013	2.9	1.4
2010	Jan	686	745,474	372,737	0.0075	0.003	2.8	1.4
	Feb	133	720,435	360,217	0.0075	0.000	2.7	1.3
	Mar	-	720,435	360,217		-	2.7	1.3
	Apr	-	710,806	355,403		-	2.6	1.3
	May	-	692,783	346,391		-	2.6	1.3
	Jun	9,634	614,895	307,447	0.0075	0.036	2.3	1.1
	Jul	64,030	585,716	292,858	0.0075	0.239	2.2	1.1
	Aug	103,982	575,114	287,557	0.0075	0.387	2.1	1.1
	Sep	92,810	624,592	312,296	0.0075	0.346	2.3	1.2
	Oct	68,919	667,375	333,687	0.0075	0.257	2.5	1.2
	Nov	144	667,117	333,558	0.0075	0.001	2.5	1.2
	Dec	-	666,966	333,483		-	2.5	1.2

TABLE E-8. Baseline actual particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			PM, PM_{10}, and $PM_{2.5}$ Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	-	666,966	333,483		-	2.5	1.2
	Feb	6,507	673,473	336,737	0.0075	0.024	2.5	1.3
	Mar	2,625	676,098	338,049	0.0075	0.010	2.5	1.3
	Apr	141	676,239	338,120	0.0075	0.001	2.5	1.3
	May	-	676,239	338,120		-	2.5	1.3
	Jun	41,581	706,968	353,484	0.0075	0.155	2.6	1.3
	Jul	116,450	663,849	331,924	0.0075	0.434	2.5	1.2
	Aug	214,780	787,510	393,755	0.0075	0.800	2.9	1.5
	Sep	70,041	809,703	404,851	0.0075	0.261	3.0	1.5
	Oct	92,177	889,034	444,517	0.0075	0.343	3.3	1.7
	Nov	699	888,732	444,366	0.0075	0.003	3.3	1.7
	Dec	20,646	905,985	452,993	0.0075	0.077	3.4	1.7
2012	Jan	-	905,299	452,650		-	3.4	1.7
	Feb	-	905,166	452,583		-	3.4	1.7
	Mar	17,911	923,078	461,539	0.0075	0.067	3.4	1.7
	Apr	24,902	947,979	473,990	0.0075	0.093	3.5	1.8
	May	58,498	1,006,477	503,238	0.0075	0.218	3.7	1.9
	Jun	115,484	1,112,327	556,164	0.0075	0.430	4.1	2.1
	Jul	61,112	1,109,410	554,705	0.0075	0.228	4.1	2.1
	Aug	155,558	1,160,986	580,493	0.0075	0.580	4.3	2.2
	Sep	61,083	1,129,259	564,629	0.0075	0.228	4.2	2.1
	Oct	25,256	1,085,595	542,798	0.0075	0.094	4.0	2.0
	Nov	132	1,085,583	542,792	0.0075	0.000	4.0	2.0
	Dec	9,800	1,095,383	547,691	0.0075	0.037	4.1	2.0
2013	Jan	58,429	1,153,812	576,906	0.0075	0.218	4.3	2.1
	Feb	4,345	1,151,650	575,825	0.0075	0.016	4.3	2.1
	Mar	1,045	1,150,070	575,035	0.0075	0.004	4.3	2.1
	Apr	12,952	1,162,881	581,440	0.0075	0.048	4.3	2.2
	May	38,778	1,201,659	600,830	0.0075	0.144	4.5	2.2
	Jun	132,850	1,292,928	646,464	0.0075	0.495	4.8	2.4
	July	153,657	1,330,134	665,067	0.0075	0.572	5.0	2.5
	August	143,629	1,258,983	629,491	0.0075	0.535	4.7	2.3
	September	70,759	1,259,701	629,850	0.0075	0.264	4.7	2.3
	October	241	1,167,765	583,882	0.0075	0.001	4.4	2.2
	November	17,978	1,185,044	592,522	0.0075	0.067	4.4	2.2
	December	18,106	1,182,503	591,252	0.0075	0.067	4.4	2.2
2014	January	31,521	1,214,024	607,012	0.0075	0.117	4.5	2.3
	February	5,698	1,219,722	609,861	0.0075	0.021	4.5	2.3

TABLE E-9. Baseline actual particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			PM, PM_{10}, and $PM_{2.5}$ Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	15,421			0.0075	0.057		
	Feb	26,358			0.0075	0.098		
	Mar	-				-		
	Apr	1,896			0.0075	0.007		
	May	14,503			0.0075	0.054		
	Jun	89,587			0.0075	0.334		
	Jul	90,637			0.0075	0.338		
	Aug	79,336			0.0075	0.296		
	Sep	76,799			0.0075	0.286		
	Oct	80,639			0.0075	0.300		
	Nov	12,131			0.0075	0.045		
	Dec	-				-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			0.0075	0.002		
	May	163,171			0.0075	0.608		
	Jun	61,573			0.0075	0.229		
	Jul	169,916			0.0075	0.633		
	Aug	161,270			0.0075	0.601		
	Sep	81,486			0.0075	0.304		
	Oct	13,265			0.0075	0.049		
	Nov	12,745			0.0075	0.047		
	Dec	7,705	1,158,934	579,467	0.0075	0.029	4.3	2.2
2010	Jan	450	1,143,962	571,981	0.0075	0.002	4.3	2.1
	Feb	138	1,117,742	558,871	0.0075	0.001	4.2	2.1
	Mar	-	1,117,742	558,871		-	4.2	2.1
	Apr	1,200	1,117,046	558,523	0.0075	0.004	4.2	2.1
	May	-	1,102,543	551,271		-	4.1	2.1
	Jun	6,599	1,019,554	509,777	0.0075	0.025	3.8	1.9
	Jul	44,585	973,503	486,751	0.0075	0.166	3.6	1.8
	Aug	144,204	1,038,371	519,186	0.0075	0.537	3.9	1.9
	Sep	67,249	1,028,822	514,411	0.0075	0.251	3.8	1.9
	Oct	71,331	1,019,513	509,757	0.0075	0.266	3.8	1.9
	Nov	2,177	1,009,559	504,780	0.0075	0.008	3.8	1.9
	Dec	-	1,009,559	504,780		-	3.8	1.9

TABLE E-9. Baseline actual particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			PM, PM_{10}, and $PM_{2.5}$ Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,014,040	507,020	0.0075	0.017	3.8	1.9
	Feb	20,220	1,034,260	517,130	0.0075	0.075	3.9	1.9
	Mar	-	1,034,260	517,130		-	3.9	1.9
	Apr	1,630	1,035,394	517,697	0.0075	0.006	3.9	1.9
	May	-	872,223	436,112		-	3.2	1.6
	Jun	54,333	864,983	432,492	0.0075	0.202	3.2	1.6
	Jul	164,320	859,387	429,694	0.0075	0.612	3.2	1.6
	Aug	180,411	878,528	439,264	0.0075	0.672	3.3	1.6
	Sep	64,736	861,778	430,889	0.0075	0.241	3.2	1.6
	Oct	111,748	960,260	480,130	0.0075	0.416	3.6	1.8
	Nov	4,053	951,568	475,784	0.0075	0.015	3.5	1.8
	Dec	9,537	953,400	476,700	0.0075	0.036	3.6	1.8
2012	Jan	-	952,951	476,475		-	3.6	1.8
	Feb	-	952,812	476,406		-	3.5	1.8
	Mar	1,382	954,194	477,097	0.0075	0.005	3.6	1.8
	Apr	86,134	1,039,128	519,564	0.0075	0.321	3.9	1.9
	May	50,881	1,090,010	545,005	0.0075	0.190	4.1	2.0
	Jun	91,607	1,175,018	587,509	0.0075	0.341	4.4	2.2
	Jul	29,312	1,159,745	579,872	0.0075	0.109	4.3	2.2
	Aug	120,697	1,136,238	568,119	0.0075	0.450	4.2	2.1
	Sep	13,110	1,082,098	541,049	0.0075	0.049	4.0	2.0
	Oct	786	1,011,554	505,777	0.0075	0.003	3.8	1.9
	Nov	-	1,009,377	504,688		-	3.8	1.9
	Dec	7,294	1,016,671	508,336	0.0075	0.027	3.8	1.9
2013	Jan	28,020	1,040,210	520,105	0.0075	0.104	3.9	1.9
	Feb	3,526	1,023,516	511,758	0.0075	0.013	3.8	1.9
	Mar	-	1,023,516	511,758		-	3.8	1.9
	Apr	29,529	1,051,416	525,708	0.0075	0.110	3.9	2.0
	May	22,968	1,074,384	537,192	0.0075	0.086	4.0	2.0
	Jun	116,778	1,136,830	568,415	0.0075	0.435	4.2	2.1
	July	367,709	1,340,219	670,110	0.0075	1.370	5.0	2.5
	August	123,204	1,283,012	641,506	0.0075	0.459	4.8	2.4
	September	68,549	1,286,825	643,413	0.0075	0.255	4.8	2.4
	October	6,688	1,181,765	590,883	0.0075	0.025	4.4	2.2
	November	30,501	1,208,213	604,107	0.0075	0.114	4.5	2.3
	December	45,037	1,243,714	621,857	0.0075	0.168	4.6	2.3
2014	January	12,217	1,255,931	627,965	0.0075	0.046	4.7	2.3
	February	13,749	1,269,680	634,840	0.0075	0.051	4.7	2.4

TABLE E-10. Baseline actual PM, PM_{10}, and $PM_{2.5}$ emissions for Ocotillo Steamers 1 and 2 combined.

Year	Month	Heat Input			PM, PM_{10}, and $PM_{2.5}$ Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	45,835			0.0075	0.171		
	Feb	51,530			0.0075	0.192		
	Mar	-				-		
	Apr	11,525			0.0075	0.043		
	May	32,526			0.0075	0.121		
	Jun	177,110			0.0075	0.660		
	Jul	183,845			0.0075	0.685		
	Aug	193,920			0.0075	0.722		
	Sep	120,131			0.0075	0.448		
	Oct	106,776			0.0075	0.398		
	Nov	12,533			0.0075	0.047		
	Dec	151			0.0075	0.001		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			0.0075	0.002		
	May	163,171			0.0075	0.608		
	Jun	72,425			0.0075	0.270		
	Jul	329,485			0.0075	1.227		
	Aug	252,389			0.0075	0.940		
	Sep	129,335			0.0075	0.482		
	Oct	26,112			0.0075	0.097		
	Nov	13,745			0.0075	0.051		
	Dec	11,098	1,934,135	967,068	0.0075	0.041	7.2	3.6
2010	Jan	1,136	1,889,436	944,718	0.0075	0.004	7.0	3.5
	Feb	271	1,838,177	919,089	0.0075	0.001	6.8	3.4
	Mar	-	1,838,177	919,089		-	6.8	3.4
	Apr	1,200	1,827,852	913,926	0.0075	0.004	6.8	3.4
	May	-	1,795,326	897,663		-	6.7	3.3
	Jun	16,233	1,634,449	817,225	0.0075	0.060	6.1	3.0
	Jul	108,615	1,559,219	779,610	0.0075	0.405	5.8	2.9
	Aug	248,186	1,613,485	806,743	0.0075	0.925	6.0	3.0
	Sep	160,059	1,653,413	826,707	0.0075	0.596	6.2	3.1
	Oct	140,250	1,686,888	843,444	0.0075	0.523	6.3	3.1
	Nov	2,321	1,676,676	838,338	0.0075	0.009	6.2	3.1
	Dec	-	1,676,525	838,263		-	6.2	3.1

TABLE E-10. Baseline actual PM, PM_{10}, and $PM_{2.5}$ emissions for Ocotillo Steamers 1 and 2 combined.

Year	Month	Heat Input			PM, PM_{10}, and $PM_{2.5}$ Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,681,006	840,503	0.0075	0.017	6.3	3.1
	Feb	26,727	1,707,733	853,867	0.0075	0.100	6.4	3.2
	Mar	2,625	1,710,358	855,179	0.0075	0.010	6.4	3.2
	Apr	1,771	1,711,634	855,817	0.0075	0.007	6.4	3.2
	May	-	1,548,463	774,231		-	5.8	2.9
	Jun	95,913	1,571,951	785,975	0.0075	0.357	5.9	2.9
	Jul	280,770	1,523,236	761,618	0.0075	1.046	5.7	2.8
	Aug	395,192	1,666,039	833,019	0.0075	1.472	6.2	3.1
	Sep	134,776	1,671,480	835,740	0.0075	0.502	6.2	3.1
	Oct	203,925	1,849,294	924,647	0.0075	0.760	6.9	3.4
	Nov	4,752	1,840,301	920,150	0.0075	0.018	6.9	3.4
	Dec	30,183	1,859,385	929,693	0.0075	0.112	6.9	3.5
2012	Jan	-	1,858,250	929,125		-	6.9	3.5
	Feb	-	1,857,979	928,989		-	6.9	3.5
	Mar	19,293	1,877,272	938,636	0.0075	0.072	7.0	3.5
	Apr	111,035	1,987,108	993,554	0.0075	0.414	7.4	3.7
	May	109,379	2,096,487	1,048,243	0.0075	0.407	7.8	3.9
	Jun	207,092	2,287,345	1,143,673	0.0075	0.772	8.5	4.3
	Jul	90,424	2,269,154	1,134,577	0.0075	0.337	8.5	4.2
	Aug	276,255	2,297,224	1,148,612	0.0075	1.029	8.6	4.3
	Sep	74,193	2,211,357	1,105,678	0.0075	0.276	8.2	4.1
	Oct	26,042	2,097,149	1,048,575	0.0075	0.097	7.8	3.9
	Nov	132	2,094,960	1,047,480	0.0075	0.000	7.8	3.9
	Dec	17,094	2,112,054	1,056,027	0.0075	0.064	7.9	3.9
2013	Jan	86,449	2,194,022	1,097,011	0.0075	0.322	8.2	4.1
	Feb	7,871	2,175,166	1,087,583	0.0075	0.029	8.1	4.1
	Mar	1,045	2,173,586	1,086,793	0.0075	0.004	8.1	4.0
	Apr	42,481	2,214,297	1,107,148	0.0075	0.158	8.2	4.1
	May	61,747	2,276,043	1,138,022	0.0075	0.230	8.5	4.2
	Jun	249,628	2,429,758	1,214,879	0.0075	0.930	9.1	4.5
	July	521,366	2,670,354	1,335,177	0.0075	1.942	9.9	5.0
	August	266,833	2,541,994	1,270,997	0.0075	0.994	9.5	4.7
	September	139,308	2,546,526	1,273,263	0.0075	0.519	9.5	4.7
	October	6,929	2,349,530	1,174,765	0.0075	0.026	8.8	4.4
	November	48,479	2,393,257	1,196,628	0.0075	0.181	8.9	4.5
	December	63,143	2,426,217	1,213,108	0.0075	0.235	9.0	4.5
2014	January	43,738	2,469,955	1,234,977	0.0075	0.163	9.2	4.6
	February	19,447	2,489,402	1,244,701	0.0075	0.072	9.27	4.64

TABLE E-11. Baseline actual sulfur dioxide (SO_2) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Sulfur Dioxide (SO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	30,413			0.0006	0.009		
	Feb	25,172			0.0006	0.008		
	Mar	-				-		
	Apr	9,629			0.0006	0.003		
	May	18,023			0.0006	0.005		
	Jun	87,522			0.0006	0.026		
	Jul	93,208			0.0006	0.028		
	Aug	114,585			0.0006	0.034		
	Sep	43,332			0.0006	0.013		
	Oct	26,137			0.0006	0.008		
	Nov	402			-	-		
	Dec	151			-	-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	-				-		
	May	-				-		
	Jun	10,853			0.0006	0.003		
	Jul	159,569			0.0006	0.048		
	Aug	91,118			0.0006	0.027		
	Sep	47,848			0.0006	0.014		
	Oct	12,846			0.0006	0.004		
	Nov	1,000			-	-		
	Dec	3,394	775,201	387,601	0.0006	0.001	0.23	0.12
2010	Jan	686	745,474	372,737	-	-	0.22	0.11
	Feb	133	720,435	360,217	-	-	0.21	0.11
	Mar	-	720,435	360,217		-	0.21	0.11
	Apr	-	710,806	355,403		-	0.21	0.11
	May	-	692,783	346,391		-	0.21	0.10
	Jun	9,634	614,895	307,447	0.0006	0.003	0.18	0.09
	Jul	64,030	585,716	292,858	0.0006	0.019	0.17	0.09
	Aug	103,982	575,114	287,557	0.0006	0.031	0.17	0.09
	Sep	92,810	624,592	312,296	0.0006	0.028	0.19	0.09
	Oct	68,919	667,375	333,687	0.0006	0.021	0.20	0.10
	Nov	144	667,117	333,558	-	-	0.20	0.10
	Dec	-	666,966	333,483		-	0.20	0.10

TABLE E-11. Baseline actual sulfur dioxide (SO_2) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Sulfur Dioxide (SO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	-	666,966	333,483		-	0.20	0.10
	Feb	6,507	673,473	336,737	0.0006	0.002	0.20	0.10
	Mar	2,625	676,098	338,049	0.0008	0.001	0.20	0.10
	Apr	141	676,239	338,120	-	-	0.20	0.10
	May	-	676,239	338,120		-	0.20	0.10
	Jun	41,581	706,968	353,484	0.0006	0.012	0.21	0.11
	Jul	116,450	663,849	331,924	0.0006	0.035	0.20	0.10
	Aug	214,780	787,510	393,755	0.0006	0.064	0.24	0.12
	Sep	70,041	809,703	404,851	0.0006	0.021	0.24	0.12
	Oct	92,177	889,034	444,517	0.0006	0.028	0.27	0.13
	Nov	699	888,732	444,366	-	-	0.27	0.13
	Dec	20,646	905,985	452,993	0.0006	0.006	0.27	0.14
2012	Jan	-	905,299	452,650		-	0.27	0.14
	Feb	-	905,166	452,583		-	0.27	0.14
	Mar	17,911	923,078	461,539	0.0006	0.005	0.28	0.14
	Apr	24,902	947,979	473,990	0.0006	0.007	0.28	0.14
	May	58,498	1,006,477	503,238	0.0006	0.018	0.30	0.15
	Jun	115,484	1,112,327	556,164	0.0006	0.035	0.33	0.17
	Jul	61,112	1,109,410	554,705	0.0006	0.018	0.33	0.17
	Aug	155,558	1,160,986	580,493	0.0006	0.047	0.35	0.17
	Sep	61,083	1,129,259	564,629	0.0006	0.018	0.34	0.17
	Oct	25,256	1,085,595	542,798	0.0006	0.008	0.33	0.16
	Nov	132	1,085,583	542,792	-	-	0.33	0.16
	Dec	9,800	1,095,383	547,691	0.0006	0.003	0.33	0.16
2013	Jan	58,429	1,153,812	576,906	0.0006	0.018	0.35	0.17
	Feb	4,345	1,151,650	575,825	0.0005	0.001	0.35	0.17
	Mar	1,045	1,150,070	575,035	-	-	0.34	0.17
	Apr	12,952	1,162,881	581,440	0.0006	0.004	0.35	0.17
	May	38,778	1,201,659	600,830	0.0006	0.012	0.36	0.18
	Jun	132,850	1,292,928	646,464	0.0006	0.040	0.39	0.19
	July	153,657	1,330,134	665,067	0.0006	0.046	0.40	0.20
	August	143,629	1,258,983	629,491	0.0006	0.043	0.38	0.19
	September	70,759	1,259,701	629,850	0.0006	0.021	0.38	0.19
	October	241	1,167,765	583,882	-	-	0.35	0.18
	November	17,978	1,185,044	592,522	0.0006	0.005	0.36	0.18
	December	18,106	1,182,503	591,252	0.0006	0.005	0.35	0.18
2014	January	31,521	1,214,024	607,012	0.0006	0.009	0.36	0.18
	February	5,698	1,219,722	609,861	0.0006	0.002	0.36	0.18

Footnotes

SO_2 emissions are measured by the continuous emissions monitoring systems (CEMS) installed under the Federal Acid Rain Program in 40 CFR Part 75.

TABLE E-12. Baseline actual sulfur dioxide (SO_2) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Sulfur Dioxide (SO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	15,421			0.0006	0.005		
	Feb	26,358			0.0006	0.008		
	Mar	-				-		
	Apr	1,896			0.0011	0.001		
	May	14,503			0.0006	0.004		
	Jun	89,587			0.0006	0.027		
	Jul	90,637			0.0006	0.027		
	Aug	79,336			0.0006	0.024		
	Sep	76,799			0.0006	0.023		
	Oct	80,639			0.0006	0.024		
	Nov	12,131			0.0007	0.004		
	Dec	-				-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			-	-		
	May	163,171			0.0006	0.049		
	Jun	61,573			0.0006	0.018		
	Jul	169,916			0.0006	0.051		
	Aug	161,270			0.0006	0.048		
	Sep	81,486			0.0006	0.024		
	Oct	13,265			0.0006	0.004		
	Nov	12,745			0.0006	0.004		
	Dec	7,705	1,158,934	579,467	0.0005	0.002	0.35	0.17
2010	Jan	450	1,143,962	571,981	-	-	0.34	0.17
	Feb	138	1,117,742	558,871	-	-	0.33	0.17
	Mar	-	1,117,742	558,871		-	0.33	0.17
	Apr	1,200	1,117,046	558,523	-	-	0.33	0.17
	May	-	1,102,543	551,271		-	0.33	0.16
	Jun	6,599	1,019,554	509,777	0.0006	0.002	0.30	0.15
	Jul	44,585	973,503	486,751	0.0006	0.013	0.29	0.15
	Aug	144,204	1,038,371	519,186	0.0006	0.043	0.31	0.15
	Sep	67,249	1,028,822	514,411	0.0006	0.020	0.31	0.15
	Oct	71,331	1,019,513	509,757	0.0006	0.021	0.30	0.15
	Nov	2,177	1,009,559	504,780	0.0009	0.001	0.30	0.15
	Dec	-	1,009,559	504,780		-	0.30	0.15

TABLE E-12. Baseline actual sulfur dioxide (SO_2) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Sulfur Dioxide (SO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,014,040	507,020	0.0004	0.001	0.30	0.15
	Feb	20,220	1,034,260	517,130	0.0006	0.006	0.31	0.15
	Mar	-	1,034,260	517,130		-	0.31	0.15
	Apr	1,630	1,035,394	517,697	-	-	0.31	0.15
	May	-	872,223	436,112		-	0.26	0.13
	Jun	54,333	864,983	432,492	0.0006	0.016	0.26	0.13
	Jul	164,320	859,387	429,694	0.0006	0.049	0.25	0.13
	Aug	180,411	878,528	439,264	0.0006	0.054	0.26	0.13
	Sep	64,736	861,778	430,889	0.0006	0.019	0.26	0.13
	Oct	111,748	960,260	480,130	0.0006	0.034	0.29	0.14
	Nov	4,053	951,568	475,784	0.0005	0.001	0.28	0.14
	Dec	9,537	953,400	476,700	0.0006	0.003	0.28	0.14
2012	Jan	-	952,951	476,475		-	0.28	0.14
	Feb	-	952,812	476,406		-	0.28	0.14
	Mar	1,382	954,194	477,097	-	-	0.28	0.14
	Apr	86,134	1,039,128	519,564	0.0006	0.026	0.31	0.15
	May	50,881	1,090,010	545,005	0.0006	0.015	0.32	0.16
	Jun	91,607	1,175,018	587,509	0.0006	0.027	0.35	0.17
	Jul	29,312	1,159,745	579,872	0.0006	0.009	0.35	0.17
	Aug	120,697	1,136,238	568,119	0.0006	0.036	0.34	0.17
	Sep	13,110	1,082,098	541,049	0.0006	0.004	0.32	0.16
	Oct	786	1,011,554	505,777	-	-	0.30	0.15
	Nov	-	1,009,377	504,688		-	0.30	0.15
	Dec	7,294	1,016,671	508,336	0.0005	0.002	0.30	0.15
2013	Jan	28,020	1,040,210	520,105	0.0006	0.008	0.31	0.15
	Feb	3,526	1,023,516	511,758	0.0006	0.001	0.30	0.15
	Mar	-	1,023,516	511,758			0.30	0.15
	Apr	29,529	1,051,416	525,708	0.0006	0.009	0.31	0.16
	May	22,968	1,074,384	537,192	0.0006	0.007	0.32	0.16
	Jun	116,778	1,136,830	568,415	0.0006	0.035	0.34	0.17
	July	367,709	1,340,219	670,110	0.0006	0.110	0.40	0.20
	August	123,204	1,283,012	641,506	0.0006	0.037	0.38	0.19
	September	68,549	1,286,825	643,413	0.0006	0.021	0.39	0.19
	October	6,688	1,181,765	590,883	0.0006	0.002	0.35	0.18
	November	30,501	1,208,213	604,107	0.0006	0.009	0.36	0.18
	December	45,037	1,243,714	621,857	0.0006	0.014	0.37	0.19
2014	January	12,217	1,255,931	627,965	0.0006	0.003	0.38	0.19
	February	13,749	1,269,680	634,840	0.0006	0.004	0.38	0.19

Footnotes

SO_2 emissions are measured by the continuous emissions monitoring systems (CEMS) installed under the Federal Acid Rain Program in 40 CFR Part 75.

TABLE E-13. Baseline actual sulfur dioxide (SO_2) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input			Sulfur Dioxide (SO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	45,835			0.0006	0.014		
	Feb	51,530			0.0006	0.016		
	Mar	-				-		
	Apr	11,525			0.0007	0.004		
	May	32,526			0.0006	0.009		
	Jun	177,110			0.0006	0.053		
	Jul	183,845			0.0006	0.055		
	Aug	193,920			0.0006	0.058		
	Sep	120,131			0.0006	0.036		
	Oct	106,776			0.0006	0.032		
	Nov	12,533			0.0006	0.004		
	Dec	151			-	-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			-	-		
	May	163,171			0.0006	0.049		
	Jun	72,425			0.0006	0.021		
	Jul	329,485			0.0006	0.099		
	Aug	252,389			0.0006	0.075		
	Sep	129,335			0.0006	0.038		
	Oct	26,112			0.0006	0.008		
	Nov	13,745			0.0006	0.004		
	Dec	11,098	1,934,135	967,068	0.0005	0.003	0.58	0.29
2010	Jan	1,136	1,889,436	944,718	-	-	0.56	0.28
	Feb	271	1,838,177	919,089	-	-	0.55	0.27
	Mar	-	1,838,177	919,089		-	0.55	0.27
	Apr	1,200	1,827,852	913,926	-	-	0.54	0.27
	May	-	1,795,326	897,663		-	0.54	0.27
	Jun	16,233	1,634,449	817,225	0.0006	0.005	0.49	0.24
	Jul	108,615	1,559,219	779,610	0.0006	0.032	0.46	0.23
	Aug	248,186	1,613,485	806,743	0.0006	0.074	0.48	0.24
	Sep	160,059	1,653,413	826,707	0.0006	0.048	0.49	0.25
	Oct	140,250	1,686,888	843,444	0.0006	0.042	0.50	0.25
	Nov	2,321	1,676,676	838,338	0.0009	0.001	0.50	0.25
	Dec	-	1,676,525	838,263		-	0.50	0.25

TABLE E-13. Baseline actual sulfur dioxide (SO_2) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input			Sulfur Dioxide (SO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,681,006	840,503	0.0004	0.001	0.50	0.25
	Feb	26,727	1,707,733	853,867	0.0006	0.008	0.51	0.25
	Mar	2,625	1,710,358	855,179	0.0008	0.001	0.51	0.25
	Apr	1,771	1,711,634	855,817	-	-	0.51	0.25
	May	-	1,548,463	774,231		-	0.46	0.23
	Jun	95,913	1,571,951	785,975	0.0006	0.028	0.47	0.23
	Jul	280,770	1,523,236	761,618	0.0006	0.084	0.45	0.23
	Aug	395,192	1,666,039	833,019	0.0006	0.118	0.50	0.25
	Sep	134,776	1,671,480	835,740	0.0006	0.040	0.50	0.25
	Oct	203,925	1,849,294	924,647	0.0006	0.062	0.55	0.28
	Nov	4,752	1,840,301	920,150	0.0004	0.001	0.55	0.27
	Dec	30,183	1,859,385	929,693	0.0006	0.009	0.55	0.28
2012	Jan	-	1,858,250	929,125		-	0.55	0.28
	Feb	-	1,857,979	928,989		-	0.55	0.28
	Mar	19,293	1,877,272	938,636	0.0005	0.005	0.56	0.28
	Apr	111,035	1,987,108	993,554	0.0006	0.033	0.59	0.30
	May	109,379	2,096,487	1,048,243	0.0006	0.033	0.63	0.31
	Jun	207,092	2,287,345	1,143,673	0.0006	0.062	0.68	0.34
	Jul	90,424	2,269,154	1,134,577	0.0006	0.027	0.68	0.34
	Aug	276,255	2,297,224	1,148,612	0.0006	0.083	0.69	0.34
	Sep	74,193	2,211,357	1,105,678	0.0006	0.022	0.66	0.33
	Oct	26,042	2,097,149	1,048,575	0.0006	0.008	0.63	0.31
	Nov	132	2,094,960	1,047,480	-	-	0.63	0.31
	Dec	17,094	2,112,054	1,056,027	0.0006	0.005	0.63	0.32
2013	Jan	86,449	2,194,022	1,097,011	0.0006	0.026	0.66	0.33
	Feb	7,871	2,175,166	1,087,583	0.0005	0.002	0.65	0.32
	Mar	1,045	2,173,586	1,086,793	-	-	0.65	0.32
	Apr	42,481	2,214,297	1,107,148	0.0006	0.013	0.66	0.33
	May	61,747	2,276,043	1,138,022	0.0006	0.019	0.68	0.34
	Jun	249,628	2,429,758	1,214,879	0.0006	0.075	0.73	0.36
	July	521,366	2,670,354	1,335,177	0.0006	0.156	0.80	0.40
	August	266,833	2,541,994	1,270,997	0.0006	0.080	0.76	0.38
	September	139,308	2,546,526	1,273,263	0.0006	0.042	0.76	0.38
	October	6,929	2,349,530	1,174,765	0.0006	0.002	0.70	0.35
	November	48,479	2,393,257	1,196,628	0.0006	0.014	0.72	0.36
	December	63,143	2,426,217	1,213,108	0.0006	0.019	0.73	0.36
2014	January	43,738	2,469,955	1,234,977	0.0006	0.012	0.74	0.37
	February	19,447	2,489,402	1,244,701	0.0006	0.005	0.74	0.37

Footnotes

SO_2 emissions are measured by the continuous emissions monitoring systems (CEMS) installed under the Federal Acid Rain Program in 40 CFR Part 75.

TABLE E-14. Baseline actual volatile organic compound (VOC) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Volatile Organic Compounds (VOC) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	30,413			0.0055	0.084		
	Feb	25,172			0.0055	0.069		
	Mar	-			0.0055	-		
	Apr	9,629			0.0055	0.026		
	May	18,023			0.0055	0.050		
	Jun	87,522			0.0055	0.241		
	Jul	93,208			0.0055	0.256		
	Aug	114,585			0.0055	0.315		
	Sep	43,332			0.0055	0.119		
	Oct	26,137			0.0055	0.072		
	Nov	402			0.0055	0.001		
	Dec	151			0.0055	0.000		
2009	Jan	-			0.0055	-		
	Feb	-			0.0055	-		
	Mar	-			0.0055	-		
	Apr	-			0.0055	-		
	May	-			0.0055	-		
	Jun	10,853			0.0055	0.030		
	Jul	159,569			0.0055	0.439		
	Aug	91,118			0.0055	0.251		
	Sep	47,848			0.0055	0.132		
	Oct	12,846			0.0055	0.035		
	Nov	1,000			0.0055	0.003		
	Dec	3,394	775,201	387,601	0.0055	0.009	2.1	1.1
2010	Jan	686	745,474	372,737	0.0055	0.002	2.1	1.0
	Feb	133	720,435	360,217	0.0055	0.000	2.0	1.0
	Mar	-	720,435	360,217	0.0055	-	2.0	1.0
	Apr	-	710,806	355,403	0.0055	-	2.0	1.0
	May	-	692,783	346,391	0.0055	-	1.9	1.0
	Jun	9,634	614,895	307,447	0.0055	0.026	1.7	0.8
	Jul	64,030	585,716	292,858	0.0055	0.176	1.6	0.8
	Aug	103,982	575,114	287,557	0.0055	0.286	1.6	0.8
	Sep	92,810	624,592	312,296	0.0055	0.255	1.7	0.9
	Oct	68,919	667,375	333,687	0.0055	0.190	1.8	0.9
	Nov	144	667,117	333,558	0.0055	0.000	1.8	0.9
	Dec	-	666,966	333,483	0.0055	-	1.8	0.9

TABLE E-14. Baseline actual volatile organic compound (VOC) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Volatile Organic Compounds (VOC) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	-	666,966	333,483	0.0055	-	1.8	0.9
	Feb	6,507	673,473	336,737	0.0055	0.018	1.9	0.9
	Mar	2,625	676,098	338,049	0.0055	0.007	1.9	0.9
	Apr	141	676,239	338,120	0.0055	0.000	1.9	0.9
	May	-	676,239	338,120	0.0055	-	1.9	0.9
	Jun	41,581	706,968	353,484	0.0055	0.114	1.9	1.0
	Jul	116,450	663,849	331,924	0.0055	0.320	1.8	0.9
	Aug	214,780	787,510	393,755	0.0055	0.591	2.2	1.1
	Sep	70,041	809,703	404,851	0.0055	0.193	2.2	1.1
	Oct	92,177	889,034	444,517	0.0055	0.253	2.4	1.2
	Nov	699	888,732	444,366	0.0055	0.002	2.4	1.2
	Dec	20,646	905,985	452,993	0.0055	0.057	2.5	1.2
2012	Jan	-	905,299	452,650	0.0055	-	2.5	1.2
	Feb	-	905,166	452,583	0.0055	-	2.5	1.2
	Mar	17,911	923,078	461,539	0.0055	0.049	2.5	1.3
	Apr	24,902	947,979	473,990	0.0055	0.068	2.6	1.3
	May	58,498	1,006,477	503,238	0.0055	0.161	2.8	1.4
	Jun	115,484	1,112,327	556,164	0.0055	0.318	3.1	1.5
	Jul	61,112	1,109,410	554,705	0.0055	0.168	3.1	1.5
	Aug	155,558	1,160,986	580,493	0.0055	0.428	3.2	1.6
	Sep	61,083	1,129,259	564,629	0.0055	0.168	3.1	1.6
	Oct	25,256	1,085,595	542,798	0.0055	0.069	3.0	1.5
	Nov	132	1,085,583	542,792	0.0055	0.000	3.0	1.5
	Dec	9,800	1,095,383	547,691	0.0055	0.027	3.0	1.5
2013	Jan	58,429	1,153,812	576,906	0.0055	0.161	3.2	1.6
	Feb	4,345	1,151,650	575,825	0.0055	0.012	3.2	1.6
	Mar	1,045	1,150,070	575,035	0.0055	0.003	3.2	1.6
	Apr	12,952	1,162,881	581,440	0.0055	0.036	3.2	1.6
	May	38,778	1,201,659	600,830	0.0055	0.107	3.3	1.7
	Jun	132,850	1,292,928	646,464	0.0055	0.365	3.6	1.8
	July	153,657	1,330,134	665,067	0.0055	0.423	3.7	1.8
	August	143,629	1,258,983	629,491	0.0055	0.395	3.5	1.7
	September	70,759	1,259,701	629,850	0.0055	0.195	3.5	1.7
	October	241	1,167,765	583,882	0.0055	0.001	3.2	1.6
	November	17,978	1,185,044	592,522	0.0055	0.049	3.3	1.6
	December	18,106	1,182,503	591,252	0.0055	0.050	3.3	1.6
2014	January	31,521	1,214,024	607,012	0.0055	0.087	3.3	1.7
	February	5,698	1,219,722	609,861	0.0055	0.016	3.4	1.7

Footnotes

1. The controlled VOC emission factor is from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42* , 5th Edition, Table 1.4-2, and a natural gas heat value of 1,000 Btu per standard cubic foot.

TABLE E-15. Baseline actual volatile organic compound (VOC) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Volatile Organic Compounds (VOC) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	15,421			0.0055	0.042		
	Feb	26,358			0.0055	0.072		
	Mar	-			0.0055	-		
	Apr	1,896			0.0055	0.005		
	May	14,503			0.0055	0.040		
	Jun	89,587			0.0055	0.246		
	Jul	90,637			0.0055	0.249		
	Aug	79,336			0.0055	0.218		
	Sep	76,799			0.0055	0.211		
	Oct	80,639			0.0055	0.222		
	Nov	12,131			0.0055	0.033		
	Dec	-			0.0055	-		
2009	Jan	-			0.0055	-		
	Feb	-			0.0055	-		
	Mar	-			0.0055	-		
	Apr	495			0.0055	0.001		
	May	163,171			0.0055	0.449		
	Jun	61,573			0.0055	0.169		
	Jul	169,916			0.0055	0.467		
	Aug	161,270			0.0055	0.443		
	Sep	81,486			0.0055	0.224		
	Oct	13,265			0.0055	0.036		
	Nov	12,745			0.0055	0.035		
	Dec	7,705	1,158,934	579,467	0.0055	0.021	3.2	1.6
2010	Jan	450	1,143,962	571,981	0.0055	0.001	3.1	1.6
	Feb	138	1,117,742	558,871	0.0055	0.000	3.1	1.5
	Mar	-	1,117,742	558,871	0.0055	-	3.1	1.5
	Apr	1,200	1,117,046	558,523	0.0055	0.003	3.1	1.5
	May	-	1,102,543	551,271	0.0055	-	3.0	1.5
	Jun	6,599	1,019,554	509,777	0.0055	0.018	2.8	1.4
	Jul	44,585	973,503	486,751	0.0055	0.123	2.7	1.3
	Aug	144,204	1,038,371	519,186	0.0055	0.397	2.9	1.4
	Sep	67,249	1,028,822	514,411	0.0055	0.185	2.8	1.4
	Oct	71,331	1,019,513	509,757	0.0055	0.196	2.8	1.4
	Nov	2,177	1,009,559	504,780	0.0055	0.006	2.8	1.4
	Dec	-	1,009,559	504,780	0.0055	-	2.8	1.4

TABLE E-15. Baseline actual volatile organic compound (VOC) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Volatile Organic Compounds (VOC) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,014,040	507,020	0.0055	0.012	2.8	1.4
	Feb	20,220	1,034,260	517,130	0.0055	0.056	2.8	1.4
	Mar	-	1,034,260	517,130	0.0055	-	2.8	1.4
	Apr	1,630	1,035,394	517,697	0.0055	0.004	2.8	1.4
	May	-	872,223	436,112	0.0055	-	2.4	1.2
	Jun	54,333	864,983	432,492	0.0055	0.149	2.4	1.2
	Jul	164,320	859,387	429,694	0.0055	0.452	2.4	1.2
	Aug	180,411	878,528	439,264	0.0055	0.496	2.4	1.2
	Sep	64,736	861,778	430,889	0.0055	0.178	2.4	1.2
	Oct	111,748	960,260	480,130	0.0055	0.307	2.6	1.3
	Nov	4,053	951,568	475,784	0.0055	0.011	2.6	1.3
	Dec	9,537	953,400	476,700	0.0055	0.026	2.6	1.3
2012	Jan	-	952,951	476,475	0.0055	-	2.6	1.3
	Feb	-	952,812	476,406	0.0055	-	2.6	1.3
	Mar	1,382	954,194	477,097	0.0055	0.004	2.6	1.3
	Apr	86,134	1,039,128	519,564	0.0055	0.237	2.9	1.4
	May	50,881	1,090,010	545,005	0.0055	0.140	3.0	1.5
	Jun	91,607	1,175,018	587,509	0.0055	0.252	3.2	1.6
	Jul	29,312	1,159,745	579,872	0.0055	0.081	3.2	1.6
	Aug	120,697	1,136,238	568,119	0.0055	0.332	3.1	1.6
	Sep	13,110	1,082,098	541,049	0.0055	0.036	3.0	1.5
	Oct	786	1,011,554	505,777	0.0055	0.002	2.8	1.4
	Nov	-	1,009,377	504,688	0.0055	-	2.8	1.4
	Dec	7,294	1,016,671	508,336	0.0055	0.020	2.8	1.4
2013	Jan	28,020	1,040,210	520,105	0.0055	0.077	2.9	1.4
	Feb	3,526	1,023,516	511,758	0.0055	0.010	2.8	1.4
	Mar	-	1,023,516	511,758	0.0055	-	2.8	1.4
	Apr	29,529	1,051,416	525,708	0.0055	0.081	2.9	1.4
	May	22,968	1,074,384	537,192	0.0055	0.063	3.0	1.5
	Jun	116,778	1,136,830	568,415	0.0055	0.321	3.1	1.6
	July	367,709	1,340,219	670,110	0.0055	1.011	3.7	1.8
	August	123,204	1,283,012	641,506	0.0055	0.339	3.5	1.8
	September	68,549	1,286,825	643,413	0.0055	0.189	3.5	1.8
	October	6,688	1,181,765	590,883	0.0055	0.018	3.2	1.6
	November	30,501	1,208,213	604,107	0.0055	0.084	3.3	1.7
	December	45,037	1,243,714	621,857	0.0055	0.124	3.4	1.7
2014	January	12,217	1,255,931	627,965	0.0055	0.034	3.5	1.7
	February	13,749	1,269,680	634,840	0.0055	0.038	3.5	1.7

Footnotes

1. The controlled VOC emission factor is from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42* , 5th Edition, Table 1.4-2, and a natural gas heat value of 1,000 Btu per standard cubic foot.

TABLE E-16. Baseline actual VOC emissions for Ocotillo Steamers 1 and 2 combined.

Year	Month	Heat Input			Volatile Organic Compounds (VOC) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	45,835			0.0055	0.126		
	Feb	51,530			0.0055	0.142		
	Mar	-				-		
	Apr	11,525			0.0055	0.032		
	May	32,526			0.0055	0.089		
	Jun	177,110			0.0055	0.487		
	Jul	183,845			0.0055	0.506		
	Aug	193,920			0.0055	0.533		
	Sep	120,131			0.0055	0.330		
	Oct	106,776			0.0055	0.294		
	Nov	12,533			0.0055	0.034		
	Dec	151				0.000		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495				0.001		
	May	163,171			0.0055	0.449		
	Jun	72,425			0.0055	0.199		
	Jul	329,485			0.0055	0.906		
	Aug	252,389			0.0055	0.694		
	Sep	129,335			0.0055	0.356		
	Oct	26,112			0.0055	0.072		
	Nov	13,745			0.0055	0.038		
	Dec	11,098	1,934,135	967,068	0.0055	0.031	5.3	2.7
2010	Jan	1,136	1,889,436	944,718		0.003	5.2	2.6
	Feb	271	1,838,177	919,089		0.001	5.1	2.5
	Mar	-	1,838,177	919,089		-	5.1	2.5
	Apr	1,200	1,827,852	913,926		0.003	5.0	2.5
	May	-	1,795,326	897,663		-	4.9	2.5
	Jun	16,233	1,634,449	817,225	0.0055	0.045	4.5	2.2
	Jul	108,615	1,559,219	779,610	0.0055	0.299	4.3	2.1
	Aug	248,186	1,613,485	806,743	0.0055	0.683	4.4	2.2
	Sep	160,059	1,653,413	826,707	0.0055	0.440	4.5	2.3
	Oct	140,250	1,686,888	843,444	0.0055	0.386	4.6	2.3
	Nov	2,321	1,676,676	838,338	0.0055	0.006	4.6	2.3
	Dec	-	1,676,525	838,263		-	4.6	2.3

TABLE E-16. Baseline actual VOC emissions for Ocotillo Steamers 1 and 2 combined.

Year	Month	Heat Input			Volatile Organic Compounds (VOC) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,681,006	840,503	0.0055	0.012	4.6	2.3
	Feb	26,727	1,707,733	853,867	0.0055	0.073	4.7	2.3
	Mar	2,625	1,710,358	855,179	0.0055	0.007	4.7	2.4
	Apr	1,771	1,711,634	855,817		0.005	4.7	2.4
	May	-	1,548,463	774,231		-	4.3	2.1
	Jun	95,913	1,571,951	785,975	0.0055	0.264	4.3	2.2
	Jul	280,770	1,523,236	761,618	0.0055	0.772	4.2	2.1
	Aug	395,192	1,666,039	833,019	0.0055	1.087	4.6	2.3
	Sep	134,776	1,671,480	835,740	0.0055	0.371	4.6	2.3
	Oct	203,925	1,849,294	924,647	0.0055	0.561	5.1	2.5
	Nov	4,752	1,840,301	920,150	0.0055	0.013	5.1	2.5
	Dec	30,183	1,859,385	929,693	0.0055	0.083	5.1	2.6
2012	Jan	-	1,858,250	929,125		-	5.1	2.6
	Feb	-	1,857,979	928,989		-	5.1	2.6
	Mar	19,293	1,877,272	938,636	0.0055	0.053	5.2	2.6
	Apr	111,035	1,987,108	993,554	0.0055	0.305	5.5	2.7
	May	109,379	2,096,487	1,048,243	0.0055	0.301	5.8	2.9
	Jun	207,092	2,287,345	1,143,673	0.0055	0.570	6.3	3.1
	Jul	90,424	2,269,154	1,134,577	0.0055	0.249	6.2	3.1
	Aug	276,255	2,297,224	1,148,612	0.0055	0.760	6.3	3.2
	Sep	74,193	2,211,357	1,105,678	0.0055	0.204	6.1	3.0
	Oct	26,042	2,097,149	1,048,575	0.0055	0.072	5.8	2.9
	Nov	132	2,094,960	1,047,480		0.000	5.8	2.9
	Dec	17,094	2,112,054	1,056,027	0.0055	0.047	5.8	2.9
2013	Jan	86,449	2,194,022	1,097,011	0.0055	0.238	6.0	3.0
	Feb	7,871	2,175,166	1,087,583	0.0055	0.022	6.0	3.0
	Mar	1,045	2,173,586	1,086,793		0.003	6.0	3.0
	Apr	42,481	2,214,297	1,107,148	0.0055	0.117	6.1	3.0
	May	61,747	2,276,043	1,138,022	0.0055	0.170	6.3	3.1
	Jun	249,628	2,429,758	1,214,879	0.0055	0.686	6.7	3.3
	July	521,366	2,670,354	1,335,177	0.0055	1.434	7.3	3.7
	August	266,833	2,541,994	1,270,997	0.0055	0.734	7.0	3.5
	September	139,308	2,546,526	1,273,263	0.0055	0.383	7.0	3.5
	October	6,929	2,349,530	1,174,765	0.0055	0.019	6.5	3.2
	November	48,479	2,393,257	1,196,628	0.0055	0.133	6.6	3.3
	December	63,143	2,426,217	1,213,108	0.0055	0.174	6.7	3.3
2014	January	43,738	2,469,955	1,234,977	0.0055	0.120	6.8	3.4
	February	19,447	2,489,402	1,244,701	0.0055	0.053	6.8	3.4

Footnotes

1. The controlled VOC emission factor is from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42* , 5th Edition, Table 1.4-2, and a natural gas heat value of 1,000 Btu per standard cubic foot.

TABLE E-17. Baseline actual sulfuric acid mist (H_2SO_4) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Sulfuric Acid Mist (H_2SO_4) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	30,413			5.9E-07	0.000009		
	Feb	25,172			6.4E-07	0.000008		
	Mar	-				-		
	Apr	9,629			6.2E-07	0.000003		
	May	18,023			5.5E-07	0.000005		
	Jun	87,522			5.9E-07	0.000026		
	Jul	93,208			6.0E-07	0.000028		
	Aug	114,585			5.9E-07	0.000034		
	Sep	43,332			6.0E-07	0.000013		
	Oct	26,137			6.1E-07	0.000008		
	Nov	402				-		
	Dec	151			0.0E+00	-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	-				-		
	May	-				-		
	Jun	10,853			5.5E-07	0.000003		
	Jul	159,569			6.0E-07	0.000048		
	Aug	91,118			5.9E-07	0.000027		
	Sep	47,848			5.9E-07	0.000014		
	Oct	12,846			6.2E-07	0.000004		
	Nov	1,000			0.0E+00	-		
	Dec	3,394	775,201	387,601	5.9E-07	0.000001	0.0002	0.0001
2010	Jan	686	745,474	372,737		-	0.0002	0.0001
	Feb	133	720,435	360,217		-	0.0002	0.0001
	Mar	-	720,435	360,217		-	0.0002	0.0001
	Apr	-	710,806	355,403		-	0.0002	0.0001
	May	-	692,783	346,391		-	0.0002	0.0001
	Jun	9,634	614,895	307,447	6.2E-07	0.000003	0.0002	0.0001
	Jul	64,030	585,716	292,858	5.9E-07	0.000019	0.0002	0.0001
	Aug	103,982	575,114	287,557	6.0E-07	0.000031	0.0002	0.0001
	Sep	92,810	624,592	312,296	6.0E-07	0.000028	0.0002	0.0001
	Oct	68,919	667,375	333,687	6.1E-07	0.000021	0.0002	0.0001
	Nov	144	667,117	333,558	0.0E+00	-	0.0002	0.0001
	Dec	-	666,966	333,483		-	0.0002	0.0001

TABLE E-17. Baseline actual sulfuric acid mist (H_2SO_4) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Sulfuric Acid Mist (H_2SO_4) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	-	666,966	333,483		-	0.0002	0.0001
	Feb	6,507	673,473	336,737	6.1E-07	0.000002	0.0002	0.0001
	Mar	2,625	676,098	338,049	7.6E-07	0.000001	0.0002	0.0001
	Apr	141	676,239	338,120	0.0E+00	-	0.0002	0.0001
	May	-	676,239	338,120		-	0.0002	0.0001
	Jun	41,581	706,968	353,484	5.8E-07	0.000012	0.0002	0.0001
	Jul	116,450	663,849	331,924	6.0E-07	0.000035	0.0002	0.0001
	Aug	214,780	787,510	393,755	6.0E-07	0.000064	0.0002	0.0001
	Sep	70,041	809,703	404,851	6.0E-07	0.000021	0.0002	0.0001
	Oct	92,177	889,034	444,517	6.1E-07	0.000028	0.0003	0.0001
	Nov	699	888,732	444,366		-	0.0003	0.0001
	Dec	20,646	905,985	452,993	5.8E-07	0.000006	0.0003	0.0001
2012	Jan	-	905,299	452,650		-	0.0003	0.0001
	Feb	-	905,166	452,583		-	0.0003	0.0001
	Mar	17,911	923,078	461,539	5.6E-07	0.000005	0.0003	0.0001
	Apr	24,902	947,979	473,990	5.6E-07	0.000007	0.0003	0.0001
	May	58,498	1,006,477	503,238	6.2E-07	0.000018	0.0003	0.0002
	Jun	115,484	1,112,327	556,164	6.1E-07	0.000035	0.0003	0.0002
	Jul	61,112	1,109,410	554,705	5.9E-07	0.000018	0.0003	0.0002
	Aug	155,558	1,160,986	580,493	6.0E-07	0.000047	0.0003	0.0002
	Sep	61,083	1,129,259	564,629	5.9E-07	0.000018	0.0003	0.0002
	Oct	25,256	1,085,595	542,798	6.3E-07	0.000008	0.0003	0.0002
	Nov	132	1,085,583	542,792	0.0E+00	-	0.0003	0.0002
	Dec	9,800	1,095,383	547,691	6.1E-07	0.000003	0.0003	0.0002
2013	Jan	58,429	1,153,812	576,906	6.2E-07	0.000018	0.0003	0.0002
	Feb	4,345	1,151,650	575,825	4.6E-07	0.000001	0.0003	0.0002
	Mar	1,045	1,150,070	575,035		-	0.0003	0.0002
	Apr	12,952	1,162,881	581,440	6.2E-07	0.000004	0.0003	0.0002
	May	38,778	1,201,659	600,830	6.2E-07	0.000012	0.0004	0.0002
	Jun	132,850	1,292,928	646,464	6.0E-07	0.000040	0.0004	0.0002
	July	153,657	1,330,134	665,067	6.0E-07	0.000046	0.0004	0.0002
	August	143,629	1,258,983	629,491	6.0E-07	0.000043	0.0004	0.0002
	September	70,759	1,259,701	629,850	5.9E-07	0.000021	0.0004	0.0002
	October	241	1,167,765	583,882		-	0.0004	0.0002
	November	17,978	1,185,044	592,522	5.6E-07	0.000005	0.0004	0.0002
	December	18,106	1,182,503	591,252	5.5E-07	0.000005	0.0004	0.0002
2014	January	31,521	1,214,024	607,012	5.5E-07	0.000009	0.0004	0.0002
	February	5,698	1,219,722	609,861	5.5E-07	0.000002	0.0004	0.0002

Footnotes

1. Sulfuric acid mist emissions are based on 1.0% of sulfur dioxide (SO_2) emissions emitted as sulfuric acid mist.

TABLE E-18. Baseline actual sulfuric acid mist (H_2SO_4) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Sulfuric Acid Mist (H_2SO_4) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	15,421			6.5E-07	0.000005		
	Feb	26,358			6.1E-07	0.000008		
	Mar	-				-		
	Apr	1,896			1.1E-06	0.000001		
	May	14,503			5.5E-07	0.000004		
	Jun	89,587			6.0E-07	0.000027		
	Jul	90,637			6.0E-07	0.000027		
	Aug	79,336			6.1E-07	0.000024		
	Sep	76,799			6.0E-07	0.000023		
	Oct	80,639			6.0E-07	0.000024		
	Nov	12,131			6.6E-07	0.000004		
	Dec	-				-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495				-		
	May	163,171			6.0E-07	0.000049		
	Jun	61,573			5.8E-07	0.000018		
	Jul	169,916			6.0E-07	0.000051		
	Aug	161,270			6.0E-07	0.000048		
	Sep	81,486			5.9E-07	0.000024		
	Oct	13,265			6.0E-07	0.000004		
	Nov	12,745			6.3E-07	0.000004		
	Dec	7,705	1,158,934	579,467	5.2E-07	0.000002	0.0003	0.0002
2010	Jan	450	1,143,962	571,981		-	0.0003	0.0002
	Feb	138	1,117,742	558,871		-	0.0003	0.0002
	Mar	-	1,117,742	558,871		-	0.0003	0.0002
	Apr	1,200	1,117,046	558,523		-	0.0003	0.0002
	May	-	1,102,543	551,271		-	0.0003	0.0002
	Jun	6,599	1,019,554	509,777	6.1E-07	0.000002	0.0003	0.0002
	Jul	44,585	973,503	486,751	5.8E-07	0.000013	0.0003	0.0001
	Aug	144,204	1,038,371	519,186	6.0E-07	0.000043	0.0003	0.0002
	Sep	67,249	1,028,822	514,411	5.9E-07	0.000020	0.0003	0.0002
	Oct	71,331	1,019,513	509,757	5.9E-07	0.000021	0.0003	0.0002
	Nov	2,177	1,009,559	504,780	9.2E-07	0.000001	0.0003	0.0002
	Dec	-	1,009,559	504,780		-	0.0003	0.0002

TABLE E-18. Baseline actual sulfuric acid mist (H_2SO_4) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Sulfuric Acid Mist (H_2SO_4) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,014,040	507,020	4.5E-07	0.000001	0.0003	0.0002
	Feb	20,220	1,034,260	517,130	5.9E-07	0.000006	0.0003	0.0002
	Mar	-	1,034,260	517,130		-	0.0003	0.0002
	Apr	1,630	1,035,394	517,697		-	0.0003	0.0002
	May	-	872,223	436,112		-	0.0003	0.0001
	Jun	54,333	864,983	432,492	5.9E-07	0.000016	0.0003	0.0001
	Jul	164,320	859,387	429,694	6.0E-07	0.000049	0.0003	0.0001
	Aug	180,411	878,528	439,264	6.0E-07	0.000054	0.0003	0.0001
	Sep	64,736	861,778	430,889	5.9E-07	0.000019	0.0003	0.0001
	Oct	111,748	960,260	480,130	6.1E-07	0.000034	0.0003	0.0001
	Nov	4,053	951,568	475,784	4.9E-07	0.000001	0.0003	0.0001
	Dec	9,537	953,400	476,700	6.3E-07	0.000003	0.0003	0.0001
2012	Jan	-	952,951	476,475		-	0.0003	0.0001
	Feb	-	952,812	476,406		-	0.0003	0.0001
	Mar	1,382	954,194	477,097		-	0.0003	0.0001
	Apr	86,134	1,039,128	519,564	6.0E-07	0.000026	0.0003	0.0002
	May	50,881	1,090,010	545,005	5.9E-07	0.000015	0.0003	0.0002
	Jun	91,607	1,175,018	587,509	5.9E-07	0.000027	0.0003	0.0002
	Jul	29,312	1,159,745	579,872	6.1E-07	0.000009	0.0003	0.0002
	Aug	120,697	1,136,238	568,119	6.0E-07	0.000036	0.0003	0.0002
	Sep	13,110	1,082,098	541,049	6.1E-07	0.000004	0.0003	0.0002
	Oct	786	1,011,554	505,777		-	0.0003	0.0002
	Nov	-	1,009,377	504,688		-	0.0003	0.0002
	Dec	7,294	1,016,671	508,336	5.5E-07	0.000002	0.0003	0.0002
2013	Jan	28,020	1,040,210	520,105	5.7E-07	0.000008	0.0003	0.0002
	Feb	3,526	1,023,516	511,758	5.7E-07	0.000001	0.0003	0.0002
	Mar	-	1,023,516	511,758		-	0.0003	0.0002
	Apr	29,529	1,051,416	525,708	6.1E-07	0.000009	0.0003	0.0002
	May	22,968	1,074,384	537,192	6.1E-07	0.000007	0.0003	0.0002
	Jun	116,778	1,136,830	568,415	6.0E-07	0.000035	0.0003	0.0002
	July	367,709	1,340,219	670,110	6.0E-07	0.000110	0.0004	0.0002
	August	123,204	1,283,012	641,506	6.0E-07	0.000037	0.0004	0.0002
	September	68,549	1,286,825	643,413	6.1E-07	0.000021	0.0004	0.0002
	October	6,688	1,181,765	590,883	6.0E-07	0.000002	0.0004	0.0002
	November	30,501	1,208,213	604,107	5.9E-07	0.000009	0.0004	0.0002
	December	45,037	1,243,714	621,857	6.2E-07	0.000014	0.0004	0.0002
2014	January	12,217	1,255,931	627,965	5.5E-07	0.000003	0.0004	0.0002
	February	13,749	1,269,680	634,840	5.5E-07	0.000004	0.0004	0.0002

Footnotes

1. Sulfuric acid mist emissions are based on 1.0% of sulfur dioxide (SO_2) emissions emitted as sulfuric acid mist.

TABLE E-19. Baseline actual sulfuric acid mist (H_2SO_4) emissions for Ocotillo Steamers 1 and 2 combinec

Year	Month	Heat Input			Sulfuric Acid Mist (H_2SO_4) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	45,835			6.1E-07	0.000014		
	Feb	51,530			6.2E-07	0.000016		
	Mar	-				-		
	Apr	11,525			6.9E-07	0.000004		
	May	32,526			5.5E-07	0.000009		
	Jun	177,110			6.0E-07	0.000053		
	Jul	183,845			6.0E-07	0.000055		
	Aug	193,920			6.0E-07	0.000058		
	Sep	120,131			6.0E-07	0.000036		
	Oct	106,776			6.0E-07	0.000032		
	Nov	12,533			6.4E-07	0.000004		
	Dec	151				-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495				-		
	May	163,171			6.0E-07	0.000049		
	Jun	72,425			5.8E-07	0.000021		
	Jul	329,485			6.0E-07	0.000099		
	Aug	252,389			5.9E-07	0.000075		
	Sep	129,335			5.9E-07	0.000038		
	Oct	26,112			6.1E-07	0.000008		
	Nov	13,745			5.8E-07	0.000004		
	Dec	11,098	1,934,135	967,068	5.4E-07	0.000003	0.0006	0.0003
2010	Jan	1,136	1,889,436	944,718		-	0.0006	0.0003
	Feb	271	1,838,177	919,089		-	0.0005	0.0003
	Mar	-	1,838,177	919,089		-	0.0005	0.0003
	Apr	1,200	1,827,852	913,926		-	0.0005	0.0003
	May	-	1,795,326	897,663		-	0.0005	0.0003
	Jun	16,233	1,634,449	817,225	6.2E-07	0.000005	0.0005	0.0002
	Jul	108,615	1,559,219	779,610	5.9E-07	0.000032	0.0005	0.0002
	Aug	248,186	1,613,485	806,743	6.0E-07	0.000074	0.0005	0.0002
	Sep	160,059	1,653,413	826,707	6.0E-07	0.000048	0.0005	0.0002
	Oct	140,250	1,686,888	843,444	6.0E-07	0.000042	0.0005	0.0003
	Nov	2,321	1,676,676	838,338	8.6E-07	0.000001	0.0005	0.0002
	Dec	-	1,676,525	838,263		-	0.0005	0.0002

TABLE E-19. Baseline actual sulfuric acid mist (H_2SO_4) emissions for Ocotillo Steamers 1 and 2 combinec

Year	Month	Heat Input			Sulfuric Acid Mist (H_2SO_4) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,681,006	840,503	4.5E-07	0.000001	0.0005	0.0003
	Feb	26,727	1,707,733	853,867	6.0E-07	0.000008	0.0005	0.0003
	Mar	2,625	1,710,358	855,179	7.6E-07	0.000001	0.0005	0.0003
	Apr	1,771	1,711,634	855,817		-	0.0005	0.0003
	May	-	1,548,463	774,231		-	0.0005	0.0002
	Jun	95,913	1,571,951	785,975	5.8E-07	0.000028	0.0005	0.0002
	Jul	280,770	1,523,236	761,618	6.0E-07	0.000084	0.0005	0.0002
	Aug	395,192	1,666,039	833,019	6.0E-07	0.000118	0.0005	0.0002
	Sep	134,776	1,671,480	835,740	5.9E-07	0.000040	0.0005	0.0002
	Oct	203,925	1,849,294	924,647	6.1E-07	0.000062	0.0006	0.0003
	Nov	4,752	1,840,301	920,150	4.2E-07	0.000001	0.0005	0.0003
	Dec	30,183	1,859,385	929,693	6.0E-07	0.000009	0.0006	0.0003
2012	Jan	-	1,858,250	929,125		-	0.0006	0.0003
	Feb	-	1,857,979	928,989		-	0.0006	0.0003
	Mar	19,293	1,877,272	938,636	5.2E-07	0.000005	0.0006	0.0003
	Apr	111,035	1,987,108	993,554	5.9E-07	0.000033	0.0006	0.0003
	May	109,379	2,096,487	1,048,243	6.0E-07	0.000033	0.0006	0.0003
	Jun	207,092	2,287,345	1,143,673	6.0E-07	0.000062	0.0007	0.0003
	Jul	90,424	2,269,154	1,134,577	6.0E-07	0.000027	0.0007	0.0003
	Aug	276,255	2,297,224	1,148,612	6.0E-07	0.000083	0.0007	0.0003
	Sep	74,193	2,211,357	1,105,678	5.9E-07	0.000022	0.0007	0.0003
	Oct	26,042	2,097,149	1,048,575	6.1E-07	0.000008	0.0006	0.0003
	Nov	132	2,094,960	1,047,480		-	0.0006	0.0003
	Dec	17,094	2,112,054	1,056,027	5.9E-07	0.000005	0.0006	0.0003
2013	Jan	86,449	2,194,022	1,097,011	6.0E-07	0.000026	0.0007	0.0003
	Feb	7,871	2,175,166	1,087,583	5.1E-07	0.000002	0.0006	0.0003
	Mar	1,045	2,173,586	1,086,793		-	0.0006	0.0003
	Apr	42,481	2,214,297	1,107,148	6.1E-07	0.000013	0.0007	0.0003
	May	61,747	2,276,043	1,138,022	6.2E-07	0.000019	0.0007	0.0003
	Jun	249,628	2,429,758	1,214,879	6.0E-07	0.000075	0.0007	0.0004
	July	521,366	2,670,354	1,335,177	6.0E-07	0.000156	0.0008	0.0004
	August	266,833	2,541,994	1,270,997	6.0E-07	0.000080	0.0008	0.0004
	September	139,308	2,546,526	1,273,263	6.0E-07	0.000042	0.0008	0.0004
	October	6,929	2,349,530	1,174,765	5.8E-07	0.000002	0.0007	0.0004
	November	48,479	2,393,257	1,196,628	5.8E-07	0.000014	0.0007	0.0004
	December	63,143	2,426,217	1,213,108	6.0E-07	0.000019	0.0007	0.0004
2014	January	43,738	2,469,955	1,234,977	5.5E-07	0.000012	0.0007	0.0004
	February	19,447	2,489,402	1,244,701	5.5E-07	0.000005	0.0007	0.0004

Footnotes

1. Sulfuric acid mist emissions are based on 1.0% of sulfur dioxide (SO_2) emissions emitted as sulfuric acid mist.

TABLE E-20. Baseline actual lead (Pb) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Lead (Pb) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	30,413			5.0E-07	0.000008		
	Feb	25,172			5.0E-07	0.000006		
	Mar	-			5.0E-07	-		
	Apr	9,629			5.0E-07	0.000002		
	May	18,023			5.0E-07	0.000005		
	Jun	87,522			5.0E-07	0.000022		
	Jul	93,208			5.0E-07	0.000023		
	Aug	114,585			5.0E-07	0.000029		
	Sep	43,332			5.0E-07	0.000011		
	Oct	26,137			5.0E-07	0.000007		
	Nov	402			5.0E-07	0.000000		
	Dec	151			5.0E-07	0.000000		
2009	Jan	-			5.0E-07	-		
	Feb	-			5.0E-07	-		
	Mar	-			5.0E-07	-		
	Apr	-			5.0E-07	-		
	May	-			5.0E-07	-		
	Jun	10,853			5.0E-07	0.000003		
	Jul	159,569			5.0E-07	0.000040		
	Aug	91,118			5.0E-07	0.000023		
	Sep	47,848			5.0E-07	0.000012		
	Oct	12,846			5.0E-07	0.000003		
	Nov	1,000			5.0E-07	0.000000		
	Dec	3,394	775,201	387,601	5.0E-07	0.000001	0.00019	0.00010
2010	Jan	686	745,474	372,737	5.0E-07	0.000000	0.00019	0.00009
	Feb	133	720,435	360,217	5.0E-07	0.000000	0.00018	0.00009
	Mar	-	720,435	360,217	5.0E-07	-	0.00018	0.00009
	Apr	-	710,806	355,403	5.0E-07	-	0.00018	0.00009
	May	-	692,783	346,391	5.0E-07	-	0.00017	0.00009
	Jun	9,634	614,895	307,447	5.0E-07	0.000002	0.00015	0.00008
	Jul	64,030	585,716	292,858	5.0E-07	0.000016	0.00015	0.00007
	Aug	103,982	575,114	287,557	5.0E-07	0.000026	0.00014	0.00007
	Sep	92,810	624,592	312,296	5.0E-07	0.000023	0.00016	0.00008
	Oct	68,919	667,375	333,687	5.0E-07	0.000017	0.00017	0.00008
	Nov	144	667,117	333,558	5.0E-07	0.000000	0.00017	0.00008
	Dec	-	666,966	333,483	5.0E-07	-	0.00017	0.00008

TABLE E-20. Baseline actual lead (Pb) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Lead (Pb) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	-	666,966	333,483	5.0E-07	-	0.00017	0.00008
	Feb	6,507	673,473	336,737	5.0E-07	0.000002	0.00017	0.00008
	Mar	2,625	676,098	338,049	5.0E-07	0.000001	0.00017	0.00008
	Apr	141	676,239	338,120	5.0E-07	0.000000	0.00017	0.00008
	May	-	676,239	338,120	5.0E-07	-	0.00017	0.00008
	Jun	41,581	706,968	353,484	5.0E-07	0.000010	0.00018	0.00009
	Jul	116,450	663,849	331,924	5.0E-07	0.000029	0.00017	0.00008
	Aug	214,780	787,510	393,755	5.0E-07	0.000054	0.00020	0.00010
	Sep	70,041	809,703	404,851	5.0E-07	0.000018	0.00020	0.00010
	Oct	92,177	889,034	444,517	5.0E-07	0.000023	0.00022	0.00011
	Nov	699	888,732	444,366	5.0E-07	0.000000	0.00022	0.00011
	Dec	20,646	905,985	452,993	5.0E-07	0.000005	0.00023	0.00011
2012	Jan	-	905,299	452,650	5.0E-07	-	0.00023	0.00011
	Feb	-	905,166	452,583	5.0E-07	-	0.00023	0.00011
	Mar	17,911	923,078	461,539	5.0E-07	0.000004	0.00023	0.00012
	Apr	24,902	947,979	473,990	5.0E-07	0.000006	0.00024	0.00012
	May	58,498	1,006,477	503,238	5.0E-07	0.000015	0.00025	0.00013
	Jun	115,484	1,112,327	556,164	5.0E-07	0.000029	0.00028	0.00014
	Jul	61,112	1,109,410	554,705	5.0E-07	0.000015	0.00028	0.00014
	Aug	155,558	1,160,986	580,493	5.0E-07	0.000039	0.00029	0.00015
	Sep	61,083	1,129,259	564,629	5.0E-07	0.000015	0.00028	0.00014
	Oct	25,256	1,085,595	542,798	5.0E-07	0.000006	0.00027	0.00014
	Nov	132	1,085,583	542,792	5.0E-07	0.000000	0.00027	0.00014
	Dec	9,800	1,095,383	547,691	5.0E-07	0.000002	0.00027	0.00014
2013	Jan	58,429	1,153,812	576,906	5.0E-07	0.000015	0.00029	0.00014
	Feb	4,345	1,151,650	575,825	5.0E-07	0.000001	0.00029	0.00014
	Mar	1,045	1,150,070	575,035	5.0E-07	0.000000	0.00029	0.00014
	Apr	12,952	1,162,881	581,440	5.0E-07	0.000003	0.00029	0.00015
	May	38,778	1,201,659	600,830	5.0E-07	0.000010	0.00030	0.00015
	Jun	132,850	1,292,928	646,464	5.0E-07	0.000033	0.00032	0.00016
	July	153,657	1,330,134	665,067	5.0E-07	0.000038	0.00033	0.00017
	August	143,629	1,258,983	629,491	5.0E-07	0.000036	0.00031	0.00016
	September	70,759	1,259,701	629,850	5.0E-07	0.000018	0.00031	0.00016
	October	241	1,167,765	583,882	5.0E-07	0.000000	0.00029	0.00015
	November	17,978	1,185,044	592,522	5.0E-07	0.000004	0.00030	0.00015
	December	18,106	1,182,503	591,252	5.0E-07	0.000005	0.00030	0.00015
2014	January	31,521	1,214,024	607,012	5.0E-07	0.000008	0.00030	0.00015
	February	5,698	1,219,722	609,861	5.0E-07	0.000001	0.00030	0.00015

Footnotes

1. The controlled lead emission factor is from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42* , 5th Edition, Table 1.4-2, and a natural gas heat value of 1,000 Btu per standard cubic foot.

TABLE E-21. Baseline actual lead (Pb) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Lead (Pb) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	15,421			5.0E-07	0.000004		
	Feb	26,358			5.0E-07	0.000007		
	Mar	-			5.0E-07	-		
	Apr	1,896			5.0E-07	0.000000		
	May	14,503			5.0E-07	0.000004		
	Jun	89,587			5.0E-07	0.000022		
	Jul	90,637			5.0E-07	0.000023		
	Aug	79,336			5.0E-07	0.000020		
	Sep	76,799			5.0E-07	0.000019		
	Oct	80,639			5.0E-07	0.000020		
	Nov	12,131			5.0E-07	0.000003		
	Dec	-			5.0E-07	-		
2009	Jan	-			5.0E-07	-		
	Feb	-			5.0E-07	-		
	Mar	-			5.0E-07	-		
	Apr	495			5.0E-07	0.000000		
	May	163,171			5.0E-07	0.000041		
	Jun	61,573			5.0E-07	0.000015		
	Jul	169,916			5.0E-07	0.000042		
	Aug	161,270			5.0E-07	0.000040		
	Sep	81,486			5.0E-07	0.000020		
	Oct	13,265			5.0E-07	0.000003		
	Nov	12,745			5.0E-07	0.000003		
	Dec	7,705	1,158,934	579,467	5.0E-07	0.000002	0.00029	0.00014
2010	Jan	450	1,143,962	571,981	5.0E-07	0.000000	0.00029	0.00014
	Feb	138	1,117,742	558,871	5.0E-07	0.000000	0.00028	0.00014
	Mar	-	1,117,742	558,871	5.0E-07	-	0.00028	0.00014
	Apr	1,200	1,117,046	558,523	5.0E-07	0.000000	0.00028	0.00014
	May	-	1,102,543	551,271	5.0E-07	-	0.00028	0.00014
	Jun	6,599	1,019,554	509,777	5.0E-07	0.000002	0.00025	0.00013
	Jul	44,585	973,503	486,751	5.0E-07	0.000011	0.00024	0.00012
	Aug	144,204	1,038,371	519,186	5.0E-07	0.000036	0.00026	0.00013
	Sep	67,249	1,028,822	514,411	5.0E-07	0.000017	0.00026	0.00013
	Oct	71,331	1,019,513	509,757	5.0E-07	0.000018	0.00025	0.00013
	Nov	2,177	1,009,559	504,780	5.0E-07	0.000001	0.00025	0.00013
	Dec	-	1,009,559	504,780	5.0E-07	-	0.00025	0.00013

TABLE E-21. Baseline actual lead (Pb) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Lead (Pb) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,014,040	507,020	5.0E-07	0.000001	0.00025	0.00013
	Feb	20,220	1,034,260	517,130	5.0E-07	0.000005	0.00026	0.00013
	Mar	-	1,034,260	517,130	5.0E-07	-	0.00026	0.00013
	Apr	1,630	1,035,394	517,697	5.0E-07	0.000000	0.00026	0.00013
	May	-	872,223	436,112	5.0E-07	-	0.00022	0.00011
	Jun	54,333	864,983	432,492	5.0E-07	0.000014	0.00022	0.00011
	Jul	164,320	859,387	429,694	5.0E-07	0.000041	0.00021	0.00011
	Aug	180,411	878,528	439,264	5.0E-07	0.000045	0.00022	0.00011
	Sep	64,736	861,778	430,889	5.0E-07	0.000016	0.00022	0.00011
	Oct	111,748	960,260	480,130	5.0E-07	0.000028	0.00024	0.00012
	Nov	4,053	951,568	475,784	5.0E-07	0.000001	0.00024	0.00012
	Dec	9,537	953,400	476,700	5.0E-07	0.000002	0.00024	0.00012
2012	Jan	-	952,951	476,475	5.0E-07	-	0.00024	0.00012
	Feb	-	952,812	476,406	5.0E-07	-	0.00024	0.00012
	Mar	1,382	954,194	477,097	5.0E-07	0.000000	0.00024	0.00012
	Apr	86,134	1,039,128	519,564	5.0E-07	0.000022	0.00026	0.00013
	May	50,881	1,090,010	545,005	5.0E-07	0.000013	0.00027	0.00014
	Jun	91,607	1,175,018	587,509	5.0E-07	0.000023	0.00029	0.00015
	Jul	29,312	1,159,745	579,872	5.0E-07	0.000007	0.00029	0.00014
	Aug	120,697	1,136,238	568,119	5.0E-07	0.000030	0.00028	0.00014
	Sep	13,110	1,082,098	541,049	5.0E-07	0.000003	0.00027	0.00014
	Oct	786	1,011,554	505,777	5.0E-07	0.000000	0.00025	0.00013
	Nov	-	1,009,377	504,688	5.0E-07	-	0.00025	0.00013
	Dec	7,294	1,016,671	508,336	5.0E-07	0.000002	0.00025	0.00013
2013	Jan	28,020	1,040,210	520,105	5.0E-07	0.000007	0.00026	0.00013
	Feb	3,526	1,023,516	511,758	5.0E-07	0.000001	0.00026	0.00013
	Mar	-	1,023,516	511,758	5.0E-07	-	0.00026	0.00013
	Apr	29,529	1,051,416	525,708	5.0E-07	0.000007	0.00026	0.00013
	May	22,968	1,074,384	537,192	5.0E-07	0.000006	0.00027	0.00013
	Jun	116,778	1,136,830	568,415	5.0E-07	0.000029	0.00028	0.00014
	July	367,709	1,340,219	670,110	5.0E-07	0.000092	0.00034	0.00017
	August	123,204	1,283,012	641,506	5.0E-07	0.000031	0.00032	0.00016
	September	68,549	1,286,825	643,413	5.0E-07	0.000017	0.00032	0.00016
	October	6,688	1,181,765	590,883	5.0E-07	0.000002	0.00030	0.00015
	November	30,501	1,208,213	604,107	5.0E-07	0.000008	0.00030	0.00015
	December	45,037	1,243,714	621,857	5.0E-07	0.000011	0.00031	0.00016
2014	January	12,217	1,255,931	627,965	5.0E-07	0.000003	0.00031	0.00016
	February	13,749	1,269,680	634,840	5.0E-07	0.000003	0.00032	0.00016

Footnotes

1. The controlled lead emission factor is from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42* , 5th Edition, Table 1.4-2, and a natural gas heat value of 1,000 Btu per standard cubic foot.

TABLE E-22. Baseline actual lead (Pb) emissions for Ocotillo Steamers 1 and 2 combined.

Year	Month	Heat Input			Lead (Pb) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	45,835			5.0E-07	0.000011		
	Feb	51,530			5.0E-07	0.000013		
	Mar	-				-		
	Apr	11,525			5.0E-07	0.000003		
	May	32,526			5.0E-07	0.000008		
	Jun	177,110			5.0E-07	0.000044		
	Jul	183,845			5.0E-07	0.000046		
	Aug	193,920			5.0E-07	0.000048		
	Sep	120,131			5.0E-07	0.000030		
	Oct	106,776			5.0E-07	0.000027		
	Nov	12,533			5.0E-07	0.000003		
	Dec	151				0.000000		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495				0.000000		
	May	163,171			5.0E-07	0.000041		
	Jun	72,425			5.0E-07	0.000018		
	Jul	329,485			5.0E-07	0.000082		
	Aug	252,389			5.0E-07	0.000063		
	Sep	129,335			5.0E-07	0.000032		
	Oct	26,112			5.0E-07	0.000007		
	Nov	13,745			5.0E-07	0.000003		
	Dec	11,098	1,934,135	967,068	5.0E-07	0.000003	0.00048	0.00024
2010	Jan	1,136	1,889,436	944,718		0.000000	0.00047	0.00024
	Feb	271	1,838,177	919,089		0.000000	0.00046	0.00023
	Mar	-	1,838,177	919,089		-	0.00046	0.00023
	Apr	1,200	1,827,852	913,926		0.000000	0.00046	0.00023
	May	-	1,795,326	897,663		-	0.00045	0.00022
	Jun	16,233	1,634,449	817,225	5.0E-07	0.000004	0.00041	0.00020
	Jul	108,615	1,559,219	779,610	5.0E-07	0.000027	0.00039	0.00019
	Aug	248,186	1,613,485	806,743	5.0E-07	0.000062	0.00040	0.00020
	Sep	160,059	1,653,413	826,707	5.0E-07	0.000040	0.00041	0.00021
	Oct	140,250	1,686,888	843,444	5.0E-07	0.000035	0.00042	0.00021
	Nov	2,321	1,676,676	838,338	5.0E-07	0.000001	0.00042	0.00021
	Dec	-	1,676,525	838,263		-	0.00042	0.00021

TABLE E-22. Baseline actual lead (Pb) emissions for Ocotillo Steamers 1 and 2 combined.

Year	Month	Heat Input			Lead (Pb) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,681,006	840,503	5.0E-07	0.000001	0.00042	0.00021
	Feb	26,727	1,707,733	853,867	5.0E-07	0.000007	0.00043	0.00021
	Mar	2,625	1,710,358	855,179	5.0E-07	0.000001	0.00043	0.00021
	Apr	1,771	1,711,634	855,817		0.000000	0.00043	0.00021
	May	-	1,548,463	774,231		-	0.00039	0.00019
	Jun	95,913	1,571,951	785,975	5.0E-07	0.000024	0.00039	0.00020
	Jul	280,770	1,523,236	761,618	5.0E-07	0.000070	0.00038	0.00019
	Aug	395,192	1,666,039	833,019	5.0E-07	0.000099	0.00042	0.00021
	Sep	134,776	1,671,480	835,740	5.0E-07	0.000034	0.00042	0.00021
	Oct	203,925	1,849,294	924,647	5.0E-07	0.000051	0.00046	0.00023
	Nov	4,752	1,840,301	920,150	5.0E-07	0.000001	0.00046	0.00023
	Dec	30,183	1,859,385	929,693	5.0E-07	0.000008	0.00046	0.00023
2012	Jan	-	1,858,250	929,125		-	0.00046	0.00023
	Feb	-	1,857,979	928,989		-	0.00046	0.00023
	Mar	19,293	1,877,272	938,636	5.0E-07	0.000005	0.00047	0.00023
	Apr	111,035	1,987,108	993,554	5.0E-07	0.000028	0.00050	0.00025
	May	109,379	2,096,487	1,048,243	5.0E-07	0.000027	0.00052	0.00026
	Jun	207,092	2,287,345	1,143,673	5.0E-07	0.000052	0.00057	0.00029
	Jul	90,424	2,269,154	1,134,577	5.0E-07	0.000023	0.00057	0.00028
	Aug	276,255	2,297,224	1,148,612	5.0E-07	0.000069	0.00057	0.00029
	Sep	74,193	2,211,357	1,105,678	5.0E-07	0.000019	0.00055	0.00028
	Oct	26,042	2,097,149	1,048,575	5.0E-07	0.000007	0.00052	0.00026
	Nov	132	2,094,960	1,047,480		0.000000	0.00052	0.00026
	Dec	17,094	2,112,054	1,056,027	5.0E-07	0.000004	0.00053	0.00026
2013	Jan	86,449	2,194,022	1,097,011	5.0E-07	0.000022	0.00055	0.00027
	Feb	7,871	2,175,166	1,087,583	5.0E-07	0.000002	0.00054	0.00027
	Mar	1,045	2,173,586	1,086,793		0.000000	0.00054	0.00027
	Apr	42,481	2,214,297	1,107,148	5.0E-07	0.000011	0.00055	0.00028
	May	61,747	2,276,043	1,138,022	5.0E-07	0.000015	0.00057	0.00028
	Jun	249,628	2,429,758	1,214,879	5.0E-07	0.000062	0.00061	0.00030
	July	521,366	2,670,354	1,335,177	5.0E-07	0.000130	0.00067	0.00033
	August	266,833	2,541,994	1,270,997	5.0E-07	0.000067	0.00064	0.00032
	September	139,308	2,546,526	1,273,263	5.0E-07	0.000035	0.00064	0.00032
	October	6,929	2,349,530	1,174,765	5.0E-07	0.000002	0.00059	0.00029
	November	48,479	2,393,257	1,196,628	5.0E-07	0.000012	0.00060	0.00030
	December	63,143	2,426,217	1,213,108	5.0E-07	0.000016	0.00061	0.00030
2014	January	43,738	2,469,955	1,234,977	5.0E-07	0.000011	0.00062	0.00031
	February	19,447	2,489,402	1,244,701	5.0E-07	0.000005	0.00062	0.00031

Footnotes

1. The controlled lead emission factor is from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42* , 5th Edition, Table 1.4-2, and a natural gas heat value of 1,000 Btu per standard cubic foot.

TABLE E-23. Baseline actual carbon dioxide (CO_2) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Carbon Dioxide (CO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	30,413			118.8	1,806.8		
	Feb	25,172			118.9	1,496.4		
	Mar	-				-		
	Apr	9,629			118.9	572.4		
	May	18,023			118.8	1,070.9		
	Jun	87,522			118.8	5,201.0		
	Jul	93,208			118.9	5,539.5		
	Aug	114,585			118.9	6,809.7		
	Sep	43,332			118.8	2,574.8		
	Oct	26,137			118.9	1,553.5		
	Nov	402			119.2	24.0		
	Dec	151			118.5	8.9		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	-				-		
	May	-				-		
	Jun	10,853			118.9	645.2		
	Jul	159,569			118.9	9,482.8		
	Aug	91,118			118.9	5,415.3		
	Sep	47,848			118.9	2,843.7		
	Oct	12,846			118.9	763.5		
	Nov	1,000			118.7	59.3		
	Dec	3,394	775,201	387,601	118.9	201.8	46,070	23,035
2010	Jan	686	745,474	372,737	118.8	40.7	44,303	22,152
	Feb	133	720,435	360,217	118.0	7.8	42,815	21,407
	Mar	-	720,435	360,217		-	42,815	21,407
	Apr	-	710,806	355,403		-	42,243	21,121
	May	-	692,783	346,391		-	41,172	20,586
	Jun	9,634	614,895	307,447	118.8	572.5	36,543	18,272
	Jul	64,030	585,716	292,858	118.9	3,805.4	34,809	17,404
	Aug	103,982	575,114	287,557	118.9	6,180.4	34,180	17,090
	Sep	92,810	624,592	312,296	118.9	5,515.6	37,120	18,560
	Oct	68,919	667,375	333,687	118.9	4,095.6	39,663	19,831
	Nov	144	667,117	333,558	118.4	8.5	39,647	19,824
	Dec	-	666,966	333,483		-	39,638	19,819

TABLE E-23. Baseline actual carbon dioxide (CO_2) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Carbon Dioxide (CO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	-	666,966	333,483		-	39,638	19,819
	Feb	6,507	673,473	336,737	118.9	386.8	40,025	20,012
	Mar	2,625	676,098	338,049	118.9	156.0	40,181	20,090
	Apr	141	676,239	338,120	119.0	8.4	40,189	20,095
	May	-	676,239	338,120		-	40,189	20,095
	Jun	41,581	706,968	353,484	118.9	2,471.1	42,015	21,008
	Jul	116,450	663,849	331,924	118.9	6,921.4	39,454	19,727
	Aug	214,780	787,510	393,755	118.9	12,763.8	46,802	23,401
	Sep	70,041	809,703	404,851	118.8	4,162.1	48,121	24,060
	Oct	92,177	889,034	444,517	118.9	5,478.0	52,835	26,418
	Nov	699	888,732	444,366	119.0	41.6	52,818	26,409
	Dec	20,646	905,985	452,993	118.9	1,227.0	53,843	26,921
2012	Jan	-	905,299	452,650		-	53,802	26,901
	Feb	-	905,166	452,583		-	53,794	26,897
	Mar	17,911	923,078	461,539	118.9	1,064.8	54,859	27,429
	Apr	24,902	947,979	473,990	118.9	1,480.0	56,339	28,169
	May	58,498	1,006,477	503,238	118.9	3,476.6	59,816	29,908
	Jun	115,484	1,112,327	556,164	118.9	6,863.5	66,107	33,053
	Jul	61,112	1,109,410	554,705	118.9	3,631.9	65,933	32,967
	Aug	155,558	1,160,986	580,493	118.8	9,243.8	68,997	34,498
	Sep	61,083	1,129,259	564,629	118.9	3,630.1	67,111	33,555
	Oct	25,256	1,085,595	542,798	118.8	1,500.8	64,516	32,258
	Nov	132	1,085,583	542,792	118.2	7.8	64,515	32,258
	Dec	9,800	1,095,383	547,691	118.8	582.2	65,098	32,549
2013	Jan	58,429	1,153,812	576,906	118.9	3,472.5	68,570	34,285
	Feb	4,345	1,151,650	575,825	118.9	258.2	68,442	34,221
	Mar	1,045	1,150,070	575,035	118.9	62.1	68,348	34,174
	Apr	12,952	1,162,881	581,440	118.8	769.6	69,109	34,554
	May	38,778	1,201,659	600,830	118.9	2,304.4	71,413	35,707
	Jun	132,850	1,292,928	646,464	118.9	7,895.5	76,838	38,419
	July	153,657	1,330,134	665,067	118.9	9,131.4	79,048	39,524
	August	143,629	1,258,983	629,491	118.9	8,536.2	74,820	37,410
	September	70,759	1,259,701	629,850	118.9	4,204.4	74,862	37,431
	October	241	1,167,765	583,882	118.9	14.3	69,399	34,699
	November	17,978	1,185,044	592,522	118.9	1,068.9	70,426	35,213
	December	18,106	1,182,503	591,252	118.9	1,076.0	70,275	35,138
2014	January	31,521	1,214,024	607,012	118.9	1,873.3	72,148	36,074
	February	5,698	1,219,722	609,861	118.9	338.7	72,487	36,243

Footnotes

CO_2 emissions are measured by the continuous emissions monitoring systems (CEMS) installed under the Federal Acid Rain Program in 40 CFR Part 75.

TABLE E-24. Baseline actual carbon dioxide (CO_2) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Carbon Dioxide (CO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	15,421			118.9	916.7		
	Feb	26,358			118.9	1,566.5		
	Mar	-				-		
	Apr	1,896			119.0	112.8		
	May	14,503			118.8	861.9		
	Jun	89,587			118.9	5,324.4		
	Jul	90,637			118.9	5,386.6		
	Aug	79,336			118.9	4,715.0		
	Sep	76,799			118.9	4,564.3		
	Oct	80,639			118.8	4,791.9		
	Nov	12,131			118.9	721.2		
	Dec	-				-		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			119.0	29.5		
	May	163,171			118.9	9,696.5		
	Jun	61,573			118.8	3,658.9		
	Jul	169,916			118.9	10,097.4		
	Aug	161,270			118.9	9,583.9		
	Sep	81,486			118.9	4,842.8		
	Oct	13,265			118.9	788.5		
	Nov	12,745			118.8	757.2		
	Dec	7,705	1,158,934	579,467	118.8	457.7	68,874	34,437
2010	Jan	450	1,143,962	571,981	118.8	26.7	67,984	33,992
	Feb	138	1,117,742	558,871	118.5	8.2	66,425	33,213
	Mar	-	1,117,742	558,871		-	66,425	33,213
	Apr	1,200	1,117,046	558,523	118.9	71.3	66,384	33,192
	May	-	1,102,543	551,271		-	65,522	32,761
	Jun	6,599	1,019,554	509,777	118.8	392.1	60,590	30,295
	Jul	44,585	973,503	486,751	118.9	2,650.0	57,853	28,927
	Aug	144,204	1,038,371	519,186	118.9	8,570.6	61,709	30,854
	Sep	67,249	1,028,822	514,411	118.9	3,996.5	61,141	30,570
	Oct	71,331	1,019,513	509,757	118.8	4,238.6	60,587	30,294
	Nov	2,177	1,009,559	504,780	118.9	129.4	59,996	29,998
	Dec	-	1,009,559	504,780		-	59,996	29,998

TABLE E-24. Baseline actual carbon dioxide (CO_2) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Carbon Dioxide (CO_2) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,014,040	507,020	118.9	266.4	60,262	30,131
	Feb	20,220	1,034,260	517,130	118.9	1,201.6	61,464	30,732
	Mar	-	1,034,260	517,130		-	61,464	30,732
	Apr	1,630	1,035,394	517,697	119.0	97.0	61,531	30,766
	May	-	872,223	436,112		-	51,835	25,917
	Jun	54,333	864,983	432,492	118.8	3,228.3	51,404	25,702
	Jul	164,320	859,387	429,694	118.9	9,765.9	51,073	25,536
	Aug	180,411	878,528	439,264	118.9	10,721.0	52,210	26,105
	Sep	64,736	861,778	430,889	118.8	3,846.3	51,213	25,607
	Oct	111,748	960,260	480,130	118.9	6,640.7	57,066	28,533
	Nov	4,053	951,568	475,784	119.0	241.1	56,549	28,275
	Dec	9,537	953,400	476,700	118.9	567.0	56,659	28,329
2012	Jan	-	952,951	476,475		-	56,632	28,316
	Feb	-	952,812	476,406		-	56,624	28,312
	Mar	1,382	954,194	477,097	119.6	82.7	56,707	28,353
	Apr	86,134	1,039,128	519,564	118.9	5,120.3	61,755	30,878
	May	50,881	1,090,010	545,005	118.9	3,024.3	64,780	32,390
	Jun	91,607	1,175,018	587,509	118.9	5,444.1	69,832	34,916
	Jul	29,312	1,159,745	579,872	118.8	1,741.8	68,924	34,462
	Aug	120,697	1,136,238	568,119	118.8	7,172.1	67,525	33,763
	Sep	13,110	1,082,098	541,049	118.9	779.3	64,308	32,154
	Oct	786	1,011,554	505,777	119.1	46.8	60,116	30,058
	Nov	-	1,009,377	504,688		-	59,987	29,993
	Dec	7,294	1,016,671	508,336	118.9	433.5	60,420	30,210
2013	Jan	28,020	1,040,210	520,105	118.9	1,665.2	61,819	30,909
	Feb	3,526	1,023,516	511,758	119.0	209.8	60,827	30,414
	Mar	-	1,023,516	511,758		-	60,827	30,414
	Apr	29,529	1,051,416	525,708	118.9	1,754.9	62,485	31,242
	May	22,968	1,074,384	537,192	118.9	1,365.1	63,850	31,925
	Jun	116,778	1,136,830	568,415	118.9	6,940.2	67,562	33,781
	July	367,709	1,340,219	670,110	118.9	21,851.4	79,647	39,824
	August	123,204	1,283,012	641,506	118.9	7,321.8	76,248	38,124
	September	68,549	1,286,825	643,413	118.9	4,073.6	76,475	38,238
	October	6,688	1,181,765	590,883	118.9	397.5	70,232	35,116
	November	30,501	1,208,213	604,107	118.9	1,812.6	71,804	35,902
	December	45,037	1,243,714	621,857	118.9	2,676.4	73,913	36,957
2014	January	12,217	1,255,931	627,965	118.9	726.1	74,639	37,320
	February	13,749	1,269,680	634,840	118.9	817.1	75,456	37,728

Footnotes

CO_2 emissions are measured by the continuous emissions monitoring systems (CEMS) installed under the Federal Acid Rain Program in 40 CFR Part 75.

TABLE E-25. Baseline actual carbon dioxide (CO_2) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input				Carbon Dioxide (CO_2) Emissions		
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	45,835			118.8	2,723.5		
	Feb	51,530			118.9	3,062.9		
	Mar	-				-		
	Apr	11,525			118.9	685.2		
	May	32,526			118.8	1,932.8		
	Jun	177,110			118.9	10,525.4		
	Jul	183,845			118.9	10,926.1		
	Aug	193,920			118.9	11,524.7		
	Sep	120,131			118.9	7,139.1		
	Oct	106,776			118.9	6,345.4		
	Nov	12,533			118.9	745.2		
	Dec	151			118.5	8.9		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			119.0	29.5		
	May	163,171			118.9	9,696.5		
	Jun	72,425			118.9	4,304.1		
	Jul	329,485			118.9	19,580.2		
	Aug	252,389			118.9	14,999.2		
	Sep	129,335			118.9	7,686.6		
	Oct	26,112			118.9	1,552.0		
	Nov	13,745			118.8	816.5		
	Dec	11,098	1,934,135	967,068	118.8	659.5	114,943	57,472
2010	Jan	1,136	1,889,436	944,718	118.8	67.5	112,287	56,144
	Feb	271	1,838,177	919,089	118.3	16.0	109,240	54,620
	Mar	-	1,838,177	919,089		-	109,240	54,620
	Apr	1,200	1,827,852	913,926	118.9	71.3	108,626	54,313
	May	-	1,795,326	897,663		-	106,694	53,347
	Jun	16,233	1,634,449	817,225	118.8	964.6	97,133	48,566
	Jul	108,615	1,559,219	779,610	118.9	6,455.4	92,662	46,331
	Aug	248,186	1,613,485	806,743	118.9	14,751.0	95,888	47,944
	Sep	160,059	1,653,413	826,707	118.9	9,512.1	98,261	49,131
	Oct	140,250	1,686,888	843,444	118.8	8,334.1	100,250	50,125
	Nov	2,321	1,676,676	838,338	118.8	137.9	99,643	49,821
	Dec	-	1,676,525	838,263		-	99,634	49,817

TABLE E-25. Baseline actual carbon dioxide (CO_2) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input				Carbon Dioxide (CO_2) Emissions		
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,681,006	840,503	118.9	266.4	99,900	49,950
	Feb	26,727	1,707,733	853,867	118.9	1,588.4	101,489	50,744
	Mar	2,625	1,710,358	855,179	118.9	156.0	101,645	50,822
	Apr	1,771	1,711,634	855,817	119.0	105.4	101,721	50,860
	May	-	1,548,463	774,231		-	92,024	46,012
	Jun	95,913	1,571,951	785,975	118.8	5,699.4	93,419	46,710
	Jul	280,770	1,523,236	761,618	118.9	16,687.3	90,527	45,263
	Aug	395,192	1,666,039	833,019	118.9	23,484.8	99,012	49,506
	Sep	134,776	1,671,480	835,740	118.8	8,008.4	99,334	49,667
	Oct	203,925	1,849,294	924,647	118.9	12,118.8	109,901	54,950
	Nov	4,752	1,840,301	920,150	119.0	282.6	109,367	54,683
	Dec	30,183	1,859,385	929,693	118.9	1,794.0	110,502	55,251
2012	Jan	-	1,858,250	929,125		-	110,434	55,217
	Feb	-	1,857,979	928,989		-	110,418	55,209
	Mar	19,293	1,877,272	938,636	119.0	1,147.5	111,565	55,783
	Apr	111,035	1,987,108	993,554	118.9	6,600.3	118,094	59,047
	May	109,379	2,096,487	1,048,243	118.9	6,500.9	124,595	62,298
	Jun	207,092	2,287,345	1,143,673	118.9	12,307.6	135,938	67,969
	Jul	90,424	2,269,154	1,134,577	118.9	5,373.7	134,857	67,428
	Aug	276,255	2,297,224	1,148,612	118.8	16,415.8	136,522	68,261
	Sep	74,193	2,211,357	1,105,678	118.9	4,409.3	131,419	65,709
	Oct	26,042	2,097,149	1,048,575	118.9	1,547.6	124,632	62,316
	Nov	132	2,094,960	1,047,480	118.2	7.8	124,502	62,251
	Dec	17,094	2,112,054	1,056,027	118.8	1,015.8	125,518	62,759
2013	Jan	86,449	2,194,022	1,097,011	118.9	5,137.6	130,389	65,195
	Feb	7,871	2,175,166	1,087,583	118.9	467.9	129,269	64,634
	Mar	1,045	2,173,586	1,086,793	118.9	62.1	129,175	64,587
	Apr	42,481	2,214,297	1,107,148	118.9	2,524.5	131,594	65,797
	May	61,747	2,276,043	1,138,022	118.9	3,669.5	135,263	67,632
	Jun	249,628	2,429,758	1,214,879	118.9	14,835.7	144,400	72,200
	July	521,366	2,670,354	1,335,177	118.9	30,982.8	158,695	79,348
	August	266,833	2,541,994	1,270,997	118.9	15,858.0	151,068	75,534
	September	139,308	2,546,526	1,273,263	118.8	8,278.0	151,338	75,669
	October	6,929	2,349,530	1,174,765	118.9	411.9	139,631	69,815
	November	48,479	2,393,257	1,196,628	118.9	2,881.5	142,230	71,115
	December	63,143	2,426,217	1,213,108	118.9	3,752.4	144,188	72,094
2014	January	43,738	2,469,955	1,234,977	118.9	2,599.4	146,788	73,394
	February	19,447	2,489,402	1,244,701	118.9	1,155.8	147,943	73,972

Footnotes

CO_2 emissions are measured by the continuous emissions monitoring systems (CEMS) installed under the Federal Acid Rain Program in 40 CFR Part 75.

TABLE E-26. Baseline actual greenhouse gas (GHG) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Greenhouse Gas (GHG) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	30,413			118.9	1,808.6		
	Feb	25,172			119.0	1,497.8		
	Mar	-			0.1	-		
	Apr	9,629			119.0	572.9		
	May	18,023			119.0	1,072.0		
	Jun	87,522			119.0	5,206.0		
	Jul	93,208			119.0	5,544.8		
	Aug	114,585			119.0	6,816.3		
	Sep	43,332			119.0	2,577.3		
	Oct	26,137			119.0	1,555.0		
	Nov	402			119.3	24.0		
	Dec	151			118.6	8.9		
2009	Jan	-			0.1	-		
	Feb	-			0.1	-		
	Mar	-			0.1	-		
	Apr	-			0.1	-		
	May	-			0.1	-		
	Jun	10,853			119.0	645.8		
	Jul	159,569			119.0	9,491.9		
	Aug	91,118			119.0	5,420.5		
	Sep	47,848			119.0	2,846.5		
	Oct	12,846			119.0	764.3		
	Nov	1,000			118.8	59.4		
	Dec	3,394	775,201	387,601	119.0	202.0	46,114	23,057
2010	Jan	686	745,474	372,737	118.9	40.8	44,346	22,173
	Feb	133	720,435	360,217	118.1	7.8	42,856	21,428
	Mar	-	720,435	360,217	0.1	-	42,856	21,428
	Apr	-	710,806	355,403	0.1	-	42,283	21,142
	May	-	692,783	346,391	0.1	-	41,211	20,606
	Jun	9,634	614,895	307,447	119.0	573.0	36,578	18,289
	Jul	64,030	585,716	292,858	119.0	3,809.0	34,842	17,421
	Aug	103,982	575,114	287,557	119.0	6,186.3	34,213	17,106
	Sep	92,810	624,592	312,296	119.0	5,521.0	37,156	18,578
	Oct	68,919	667,375	333,687	119.0	4,099.5	39,701	19,850
	Nov	144	667,117	333,558	118.5	8.5	39,685	19,843
	Dec	-	666,966	333,483	0.1	-	39,676	19,838

TABLE E-26. Baseline actual greenhouse gas (GHG) emissions for Ocotillo Steamer 1.

Year	Month	Heat Input			Greenhouse Gas (GHG) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	-	666,966	333,483	0.1	-	39,676	19,838
	Feb	6,507	673,473	336,737	119.0	387.2	40,063	20,032
	Mar	2,625	676,098	338,049	119.0	156.2	40,220	20,110
	Apr	141	676,239	338,120	119.2	8.4	40,228	20,114
	May	-	676,239	338,120	0.1	-	40,228	20,114
	Jun	41,581	706,968	353,484	119.0	2,473.5	42,056	21,028
	Jul	116,450	663,849	331,924	119.0	6,928.1	39,492	19,746
	Aug	214,780	787,510	393,755	119.0	12,776.1	46,847	23,424
	Sep	70,041	809,703	404,851	119.0	4,166.1	48,167	24,084
	Oct	92,177	889,034	444,517	119.0	5,483.3	52,886	26,443
	Nov	699	888,732	444,366	119.1	41.6	52,868	26,434
	Dec	20,646	905,985	452,993	119.0	1,228.2	53,895	26,947
2012	Jan	-	905,299	452,650	0.1	-	53,854	26,927
	Feb	-	905,166	452,583	0.1	-	53,846	26,923
	Mar	17,911	923,078	461,539	119.0	1,065.8	54,912	27,456
	Apr	24,902	947,979	473,990	119.0	1,481.4	56,393	28,197
	May	58,498	1,006,477	503,238	119.0	3,480.0	59,873	29,937
	Jun	115,484	1,112,327	556,164	119.0	6,870.1	66,170	33,085
	Jul	61,112	1,109,410	554,705	119.0	3,635.4	65,997	32,998
	Aug	155,558	1,160,986	580,493	119.0	9,252.7	69,063	34,531
	Sep	61,083	1,129,259	564,629	119.0	3,633.5	67,176	33,588
	Oct	25,256	1,085,595	542,798	119.0	1,502.3	64,578	32,289
	Nov	132	1,085,583	542,792	118.3	7.8	64,578	32,289
	Dec	9,800	1,095,383	547,691	118.9	582.8	65,160	32,580
2013	Jan	58,429	1,153,812	576,906	119.0	3,475.8	68,636	34,318
	Feb	4,345	1,151,650	575,825	119.0	258.4	68,507	34,254
	Mar	1,045	1,150,070	575,035	119.0	62.2	68,413	34,207
	Apr	12,952	1,162,881	581,440	119.0	770.4	69,175	34,588
	May	38,778	1,201,659	600,830	119.0	2,306.6	71,482	35,741
	Jun	132,850	1,292,928	646,464	119.0	7,903.1	76,912	38,456
	July	153,657	1,330,134	665,067	119.0	9,140.9	79,124	39,562
	August	143,629	1,258,983	629,491	119.0	8,544.3	74,893	37,446
	September	70,759	1,259,701	629,850	119.0	4,209.4	74,936	37,468
	October	241	1,167,765	583,882	119.0	14.3	69,467	34,733
	November	17,978	1,185,044	592,522	119.0	1,069.5	70,495	35,247
	December	18,106	1,182,503	591,252	119.0	1,077.1	70,344	35,172
2014	January	31,521	1,214,024	607,012	119.0	1,875.1	72,219	36,109
	February	5,698	1,219,722	609,861	119.0	339.0	72,558	36,279

Footnotes

TABLE E-27. Baseline actual greenhouse gas (GHG) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Greenhouse Gas (GHG) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	15,421			119.0	917.5		
	Feb	26,358			119.0	1,568.0		
	Mar	-			0.1	-		
	Apr	1,896			119.1	112.9		
	May	14,503			119.0	862.7		
	Jun	89,587			119.0	5,329.5		
	Jul	90,637			119.0	5,391.8		
	Aug	79,336			119.0	4,719.6		
	Sep	76,799			119.0	4,568.7		
	Oct	80,639			119.0	4,796.5		
	Nov	12,131			119.0	721.9		
	Dec	-			0.1	-		
2009	Jan	-			0.1	-		
	Feb	-			0.1	-		
	Mar	-			0.1	-		
	Apr	495			119.1	29.5		
	May	163,171			119.0	9,705.8		
	Jun	61,573			119.0	3,662.4		
	Jul	169,916			119.0	10,107.1		
	Aug	161,270			119.0	9,593.1		
	Sep	81,486			119.0	4,847.5		
	Oct	13,265			119.0	789.2		
	Nov	12,745			118.9	757.9		
	Dec	7,705	1,158,934	579,467	118.9	458.1	68,940	34,470
2010	Jan	450	1,143,962	571,981	118.9	26.7	68,049	34,025
	Feb	138	1,117,742	558,871	118.6	8.2	66,489	33,245
	Mar	-	1,117,742	558,871	0.1	-	66,489	33,245
	Apr	1,200	1,117,046	558,523	119.0	71.4	66,448	33,224
	May	-	1,102,543	551,271	0.1	-	65,585	32,792
	Jun	6,599	1,019,554	509,777	119.0	392.5	60,648	30,324
	Jul	44,585	973,503	486,751	119.0	2,652.5	57,909	28,954
	Aug	144,204	1,038,371	519,186	119.0	8,578.8	61,768	30,884
	Sep	67,249	1,028,822	514,411	119.0	4,000.3	61,200	30,600
	Oct	71,331	1,019,513	509,757	119.0	4,242.6	60,646	30,323
	Nov	2,177	1,009,559	504,780	119.0	129.5	60,053	30,027
	Dec	-	1,009,559	504,780	0.1	-	60,053	30,027

TABLE E-27. Baseline actual greenhouse gas (GHG) emissions for Ocotillo Steamer 2.

Year	Month	Heat Input			Greenhouse Gas (GHG) Emissions			
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,014,040	507,020	119.0	266.7	60,320	30,160
	Feb	20,220	1,034,260	517,130	119.0	1,202.8	61,523	30,761
	Mar	-	1,034,260	517,130	0.1	-	61,523	30,761
	Apr	1,630	1,035,394	517,697	119.1	97.1	61,590	30,795
	May	-	872,223	436,112	0.1	-	51,885	25,942
	Jun	54,333	864,983	432,492	118.9	3,231.4	51,454	25,727
	Jul	164,320	859,387	429,694	119.0	9,775.3	51,122	25,561
	Aug	180,411	878,528	439,264	119.0	10,731.3	52,260	26,130
	Sep	64,736	861,778	430,889	118.9	3,850.0	51,263	25,631
	Oct	111,748	960,260	480,130	119.0	6,647.1	57,121	28,560
	Nov	4,053	951,568	475,784	119.1	241.3	56,604	28,302
	Dec	9,537	953,400	476,700	119.0	567.5	56,713	28,357
2012	Jan	-	952,951	476,475	0.1	-	56,687	28,343
	Feb	-	952,812	476,406	0.1	-	56,678	28,339
	Mar	1,382	954,194	477,097	119.8	82.7	56,761	28,381
	Apr	86,134	1,039,128	519,564	119.0	5,125.2	61,815	30,907
	May	50,881	1,090,010	545,005	119.0	3,027.2	64,842	32,421
	Jun	91,607	1,175,018	587,509	119.0	5,449.3	69,899	34,949
	Jul	29,312	1,159,745	579,872	119.0	1,743.5	68,990	34,495
	Aug	120,697	1,136,238	568,119	119.0	7,179.0	67,590	33,795
	Sep	13,110	1,082,098	541,049	119.0	780.0	64,370	32,185
	Oct	786	1,011,554	505,777	119.2	46.9	60,174	30,087
	Nov	-	1,009,377	504,688	0.1	-	60,044	30,022
	Dec	7,294	1,016,671	508,336	119.0	434.0	60,478	30,239
2013	Jan	28,020	1,040,210	520,105	119.0	1,666.8	61,878	30,939
	Feb	3,526	1,023,516	511,758	119.1	210.0	60,886	30,443
	Mar	-	1,023,516	511,758	0.1	-	60,886	30,443
	Apr	29,529	1,051,416	525,708	119.0	1,756.6	62,545	31,273
	May	22,968	1,074,384	537,192	119.0	1,366.4	63,911	31,956
	Jun	116,778	1,136,830	568,415	119.0	6,946.8	67,627	33,813
	July	367,709	1,340,219	670,110	119.0	21,874.6	79,726	39,863
	August	123,204	1,283,012	641,506	119.0	7,329.3	76,324	38,162
	September	68,549	1,286,825	643,413	119.0	4,077.9	76,552	38,276
	October	6,688	1,181,765	590,883	119.0	397.9	70,303	35,151
	November	30,501	1,208,213	604,107	119.0	1,814.5	71,876	35,938
	December	45,037	1,243,714	621,857	119.0	2,679.2	73,988	36,994
2014	January	12,217	1,255,931	627,965	119.0	726.8	74,714	37,357
	February	13,749	1,269,680	634,840	119.0	817.9	75,532	37,766

TABLE E-28. Baseline actual greenhouse gas (GHG) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input				Greenhouse Gas (GHG) Emissions		
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2008	Jan	45,835			119.0	2,726.1		
	Feb	51,530			119.0	3,065.9		
	Mar	-				-		
	Apr	11,525			119.0	685.9		
	May	32,526			119.0	1,934.7		
	Jun	177,110			119.0	10,535.5		
	Jul	183,845			119.0	10,936.6		
	Aug	193,920			119.0	11,535.8		
	Sep	120,131			119.0	7,146.0		
	Oct	106,776			119.0	6,351.5		
	Nov	12,533			119.0	745.9		
	Dec	151			118.6	8.9		
2009	Jan	-				-		
	Feb	-				-		
	Mar	-				-		
	Apr	495			119.1	29.5		
	May	163,171			119.0	9,705.8		
	Jun	72,425			119.0	4,308.2		
	Jul	329,485			119.0	19,599.0		
	Aug	252,389			119.0	15,013.6		
	Sep	129,335			119.0	7,694.0		
	Oct	26,112			119.0	1,553.5		
	Nov	13,745			118.9	817.3		
	Dec	11,098	1,934,135	967,068	119.0	660.1	115,054	57,527
2010	Jan	1,136	1,889,436	944,718	118.9	67.5	112,395	56,198
	Feb	271	1,838,177	919,089	118.4	16.0	109,345	54,673
	Mar	-	1,838,177	919,089		-	109,345	54,673
	Apr	1,200	1,827,852	913,926	119.0	71.4	108,731	54,365
	May	-	1,795,326	897,663		-	106,796	53,398
	Jun	16,233	1,634,449	817,225	119.0	965.5	97,226	48,613
	Jul	108,615	1,559,219	779,610	119.0	6,461.6	92,751	46,376
	Aug	248,186	1,613,485	806,743	119.0	14,765.2	95,981	47,990
	Sep	160,059	1,653,413	826,707	119.0	9,521.3	98,356	49,178
	Oct	140,250	1,686,888	843,444	119.0	8,342.1	100,346	50,173
	Nov	2,321	1,676,676	838,338	119.0	138.1	99,739	49,869
	Dec	-	1,676,525	838,263		-	99,730	49,865

TABLE E-28. Baseline actual greenhouse gas (GHG) emissions for Ocotillo Steamer 1 and 2 combined.

Year	Month	Heat Input				Greenhouse Gas (GHG) Emissions		
		mmBtu	24-mo total	mmBtu/yr, 24-mo ave.	lb/mmBtu	ton/mo	24-mo total	ton/yr, 24-mo ave.
2011	Jan	4,481	1,681,006	840,503	119.0	266.7	99,996	49,998
	Feb	26,727	1,707,733	853,867	119.0	1,589.9	101,586	50,793
	Mar	2,625	1,710,358	855,179	119.0	156.2	101,742	50,871
	Apr	1,771	1,711,634	855,817	119.1	105.5	101,818	50,909
	May	-	1,548,463	774,231		-	92,113	46,056
	Jun	95,913	1,571,951	785,975	119.0	5,704.9	93,509	46,755
	Jul	280,770	1,523,236	761,618	119.0	16,703.4	90,614	45,307
	Aug	395,192	1,666,039	833,019	119.0	23,507.4	99,108	49,554
	Sep	134,776	1,671,480	835,740	119.0	8,016.1	99,430	49,715
	Oct	203,925	1,849,294	924,647	119.0	12,130.5	110,007	55,003
	Nov	4,752	1,840,301	920,150	119.1	282.9	109,472	54,736
	Dec	30,183	1,859,385	929,693	119.0	1,795.7	110,608	55,304
2012	Jan	-	1,858,250	929,125		-	110,540	55,270
	Feb	-	1,857,979	928,989		-	110,524	55,262
	Mar	19,293	1,877,272	938,636	119.1	1,148.6	111,673	55,836
	Apr	111,035	1,987,108	993,554	119.0	6,606.6	118,208	59,104
	May	109,379	2,096,487	1,048,243	119.0	6,507.2	124,715	62,358
	Jun	207,092	2,287,345	1,143,673	119.0	12,319.4	136,069	68,035
	Jul	90,424	2,269,154	1,134,577	119.0	5,378.9	134,986	67,493
	Aug	276,255	2,297,224	1,148,612	119.0	16,431.6	136,653	68,326
	Sep	74,193	2,211,357	1,105,678	119.0	4,413.6	131,545	65,773
	Oct	26,042	2,097,149	1,048,575	119.0	1,549.1	124,752	62,376
	Nov	132	2,094,960	1,047,480	118.3	7.8	124,622	62,311
	Dec	17,094	2,112,054	1,056,027	119.0	1,016.7	125,639	62,819
2013	Jan	86,449	2,194,022	1,097,011	119.0	5,142.6	130,515	65,257
	Feb	7,871	2,175,166	1,087,583	119.0	468.4	129,393	64,697
	Mar	1,045	2,173,586	1,086,793	119.0	62.2	129,299	64,650
	Apr	42,481	2,214,297	1,107,148	119.0	2,526.9	131,721	65,860
	May	61,747	2,276,043	1,138,022	119.0	3,673.0	135,394	67,697
	Jun	249,628	2,429,758	1,214,879	119.0	14,849.9	144,539	72,269
	July	521,366	2,670,354	1,335,177	119.0	31,015.5	158,851	79,425
	August	266,833	2,541,994	1,270,997	119.0	15,873.6	151,217	75,608
	September	139,308	2,546,526	1,273,263	119.0	8,287.3	151,488	75,744
	October	6,929	2,349,530	1,174,765	119.0	412.2	139,770	69,885
	November	48,479	2,393,257	1,196,628	119.0	2,883.9	142,371	71,185
	December	63,143	2,426,217	1,213,108	119.0	3,756.3	144,331	72,166
2014	January	43,738	2,469,955	1,234,977	119.0	2,601.9	146,933	73,467
	February	19,447	2,489,402	1,244,701	119.0	1,156.9	148,090	74,045

TABLE E-29. Baseline actual PM, PM_{10}, and $PM_{2.5}$ emissions for the Steamer 1 and 2 cooling towers.

Year	Month	Cooling Tower (CT) 1		Cooling Tower (CT) 2		Hours for 2 Towers	PM Emissions		
		Unit 1 Hours	CT1 Hours	Unit 2 Hours	CT2 Hours		ton/mo	24-mo total	ton/yr, 24-mo ave.
2009	March	0.0	0.0	0.0	0.0	0.0	0.0		
	April	0.0	0.0	6.9	8.2	4.1	0.0		
	May	0.0	0.0	268.4	322.1	161.1	0.7		
	June	36.3	43.5	125.1	150.1	96.8	0.4		
	July	276.1	331.3	283.5	340.2	335.7	1.5		
	August	154.2	185.0	268.6	322.4	253.7	1.1		
	September	120.6	144.7	172.1	206.5	175.6	0.8		
	October	21.8	26.2	29.4	35.3	30.7	0.1		
	November	18.3	21.9	27.2	32.6	27.3	0.1		
	December	18.7	22.5	27.2	32.6	27.5	0.1		
2010	January	7.8	9.4	6.5	7.8	8.6	0.0		
	February	1.9	2.2	1.9	2.2	2.2	0.0		
	March	0.0	0.0	0.0	0.0	0.0	0.0		
	April	0.0	0.0	11.2	13.4	6.7	0.0		
	May	0.0	0.0	0.0	0.0	0.0	0.0		
	June	33.3	39.9	20.4	24.5	32.2	0.1		
	July	123.6	148.4	76.5	91.8	120.1	0.5		
	August	187.6	225.2	226.2	271.4	248.3	1.1		
	September	192.0	230.4	135.0	162.0	196.2	0.9		
	October	131.6	157.9	137.8	165.4	161.6	0.7		
	November	2.0	2.4	12.1	14.6	8.5	0.0		
	December	0.0	0.0	0.0	0.0	0.0	0.0		
2011	January	0.0	0.0	17.2	20.7	10.3	0.0		
	February	23.1	27.7	48.7	58.4	43.0	0.2	8.5	4.2
	March	17.5	21.0	0.0	0.0	10.5	0.0	8.5	4.3
	April	1.4	1.7	13.5	16.2	8.9	0.0	8.6	4.3
	May	0.0	0.0	0.0	0.0	0.0	0.0	7.9	3.9
	June	78.7	94.4	99.9	119.8	107.1	0.5	7.9	3.9
	July	236.7	284.0	278.4	334.0	309.0	1.3	7.8	3.9
	August	398.5	478.2	316.0	379.2	428.7	1.9	8.5	4.3
	September	151.3	181.5	125.5	150.6	166.0	0.7	8.5	4.2
	October	169.1	202.9	202.3	242.7	222.8	1.0	9.3	4.7
	November	5.1	6.1	18.5	22.1	14.1	0.1	9.3	4.6
	December	71.7	86.1	48.7	58.4	72.3	0.3	9.5	4.7

TABLE E-29. Baseline actual PM, PM_{10}, and $PM_{2.5}$ emissions for the Steamer 1 and 2 cooling towers.

Year	Month	Cooling Tower (CT) 1		Cooling Tower (CT) 2		Hours for 2 Towers	PM Emissions		
		Unit 1 Hours	CT1 Hours	Unit 2 Hours	CT2 Hours		ton/mo	24-mo total	ton/yr, 24-mo ave.
2012	January	0.0	0.0	0.0	0.0	0.0	0.0	9.4	4.7
	February	0.0	0.0	0.0	0.0	0.0	0.0	9.4	4.7
	March	43.6	52.3	11.2	13.4	32.8	0.1	9.6	4.8
	April	52.7	63.2	152.4	182.9	123.1	0.5	10.1	5.0
	May	113.9	136.7	118.2	141.8	139.2	0.6	10.7	5.3
	June	219.4	263.2	182.6	219.2	241.2	1.0	11.6	5.8
	July	126.3	151.5	81.0	97.2	124.4	0.5	11.6	5.8
	August	302.1	362.5	222.4	266.9	314.7	1.4	11.9	5.9
	September	132.6	159.1	36.5	43.8	101.4	0.4	11.5	5.7
	October	65.1	78.1	6.8	8.2	43.2	0.2	11.0	5.5
	November	1.6	1.9	0.0	0.0	0.9	0.0	10.9	5.5
	December	23.3	27.9	21.5	25.8	26.8	0.1	11.1	5.5
2013	January	143.1	171.7	68.7	82.4	127.1	0.6	11.6	5.8
	February	9.5	11.4	7.7	9.2	10.3	0.0	11.4	5.7
	March	10.9	13.1	0.0	0.0	6.5	0.0	11.4	5.7
	April	33.9	40.7	73.8	88.6	64.6	0.3	11.6	5.8
	May	79.2	95.1	62.2	74.6	84.8	0.4	12.0	6.0
	June	248.3	297.9	219.6	263.6	280.7	1.2	12.8	6.4
	July	288.5	346.2	721.2	865.5	605.8	2.6	14.1	7.0
	August	258.1	309.7	230.8	277.0	293.3	1.3	13.5	6.7
	September	142.1	170.5	130.6	156.7	163.6	0.7	13.5	6.7
	October	3.4	4.0	26.9	32.3	18.2	0.1	12.6	6.3
	November	53.3	64.0	70.2	84.3	74.1	0.3	12.8	6.4
	December	62.7	75.2	112.4	134.8	105.0	0.5	13.0	6.5
2014	January	89.0	106.8	42.0	50.4	78.6	0.3	13.3	6.7
	February	19.9	23.9	38.7	46.4	35.1	0.2	13.5	6.7

Footnotes

This table reports baseline actual total PM emissions. PM_{10} emissions may be calculated by multiplying the total PM emissions by 0.315; $PM_{2.5}$ emissions may be calculated by multiplying PM_{10} emissions by 0.6.

APPENDIX F.

Air Quality Analysis Protocol and Report.

APPENDIX G.

Special Status Species and Species of Concern.

EXHIBIT C – SPECIAL STATUS SPECIES AND SPECIES OF CONCERN

Arizona Revised Statutes ("ARS") §40-360 et seq. established the Power Plant and Transmission Line Siting Committee in 1971. ARS §40-360.06(A)(2) stipulates "fish, wildlife, and plant life and associated forms of life on which they are dependent" are among the factors the Siting Committee must consider in reviewing CEC applications. As stated in Arizona Corporation Commission Rules of Practice and Procedure R14-3-219:

> "*Describe any areas in the vicinity of the proposed site or route which are unique because of biological wealth or because they are habitats for rare and endangered species. Describe the biological wealth or species involved and state the effects, if any, the proposed facilities will have thereon.*"

INTRODUCTION

The Ocotillo Modernization Project ("Project") is proposed on industrial lands within the SE ¼ of Section 14, T1N, R4E (Gila-Salt River Meridian). The "project area" is defined as the footprint of the Ocotillo Power Plant ("Ocotillo Site"). The "study area" for this exhibit is defined as lands within 3 miles of the Ocotillo Site. The study area was determined through a query within the Arizona Game and Fish Department ("AGFD") online project review system, which standardizes the potential impact area by the type of project and configuration of the project area.

Applicable Laws

Endangered Species Act ("ESA"): The U.S. Fish and Wildlife Service ("USFWS") lists species as endangered, threatened, candidate, or proposed for listing, under the ESA (1973 as amended); all of these categories include organisms identified as special status species. The endangered classification is provided to an animal or plant in danger of extinction within the foreseeable future throughout all or a significant portion of its range. A threatened classification is provided to an animal or plant likely to become endangered within the foreseeable future throughout all or a significant portion of its range. Candidate species are "those species for which the USFWS has on file sufficient information on biological vulnerability and threat(s) to support issuance of a proposed rule to list, but issuance of the proposed rule is precluded." A proposed species is any species of animal or plant that is proposed in the Federal Register to be listed under Section 4 of the ESA. The ESA was designed to protect critically imperiled species from extinction as a "consequence of economic growth and development untendered by adequate concern and conservation."

The Bald and Golden Eagle Protection Act ("BGEPA"): The BGEPA was enacted in 1940, and amended several times since then, prohibits anyone, without a permit issued by the Secretary of the Interior, from "taking" eagles, including their parts, nests, or eggs. The BGEPA provides criminal penalties for persons who "take, possess, sell, purchase, barter, offer to sell, purchase or barter, transport, export or import, at any time or any manner, any bald eagle or any golden eagle, alive or dead, or any part, nest, or egg thereof." The BGEPA defines "take" as "pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb." Bald eagles and golden eagles are considered special status species.

Wildlife of Special Concern and Arizona Protected Plants: Wildlife of special concern in Arizona are species of concern for the purposes of this analysis, and plants protected by the Arizona Native Plant Law are considered special status species. Wildlife of special concern in Arizona that are listed by the AGFD have populations in the state that may be in jeopardy, have known or perceived threats, or have experienced severe population declines as described by AGFD's listing (formal legislation is pending). Additionally, most desert plants fall into one of five groups specially protected from theft, vandalism, or unnecessary destruction under the Arizona Native Plant Law. Where a project involves State Trust land or state funding, protected species require salvaging in accordance with this law (administered by the Arizona Department of Agriculture ["ADA"]). Involvement of other public or private land requires notification to ADA within a specified number of days to allow for salvaging efforts prior to removal of protected plant species.

Migratory Bird Treaty Act ("MBTA"): While not expressly conveying a special status to the covered species, the MBTA of 1918 implements various treaties and conventions between the U.S. and Canada, Japan, Mexico, and the former Soviet Union for the protection of migratory birds. Its development was in response to commercial exploitation of many bird species during the late 19th and early 20th centuries. The law establishes full protection from take, killing, possession, sale, or trade of native bird species, including their feathers, eggs, and nests unless lawfully permitted. There are currently 884 species protected by the Act, which includes most species that breed or overwinter in Arizona. These species are considered special status species.

INVENTORY

The initial assessment of biological resources for the study area identified 61 special status species or species of concern that occur in Maricopa County. Further evaluation of the natural history and distribution of these species to the existing local conditions of the study area resulted in the elimination of all but 12 of these species from further analysis. There are no federally listed species that could occur in or near the Ocotillo Site or surrounding study area due a lack of suitable habitat for these species. These species are not discussed further in the analysis.

Species and habitat information were gathered from the USFWS and AGFD (AGFD 2014, USFWS 2013). Aerial imagery, Southwest ReGAP landcover data (U.S. Geological Survey [USGS] National GAP Analysis Program 2004), soils, and topography data also were reviewed with the aid of GIS to characterize local conditions and the locations of biologically valuable areas. The AGFD Heritage Data Management System (2014 database included only the western yellow bat (*Lasiurus xanthinus*), bald eagle (*Haliaeetus leucocephalus*), lowland leopard frog (*Lithobates yavapiensis*), and Arizona chuckwalla (*Sauromalus ater*) as having documented records within 3 miles of the Ocotillo Site. The eight other species were included based on further research of other published data resources. The special status species or species of concern likely occurring in the study area outside the Ocotillo Site are detailed in Table C-1.

Based on supporting data, the study area outside the Ocotillo Site has suitable resources to sustain the species profiled in Table C-1; however, the Ocotillo Site itself lacks the habitat values necessary for these species. Table C-1 describes the habitat requirements and the locations where the species is known or where suitable habitat occurs in the surrounding study area outside the Ocotillo Site.

Table C-1. Special Status Species and Species of Concern Potentially Occurring in the Study Area

Species	Status	Habitat Requirements	Habitat Suitability
AMPHIBIANS			
Lowland leopard frog *Lithobates yavapaienesis*	USFWS-SC WSC	Occurs in big rivers, streams, ciénegas, cattle tanks, agricultural canals and ditches, mine adits, and other aquatic systems (Brennan and Holycross 2006).	**Unlikely that suitable** habitat occurs at the Ocotillo Site. The unlined, industrial pond could support the species, but water quality may not be suitable for the species. The species could occur along the Salt River, irrigation canals, or other protected impoundments outside the Ocotillo Site.
REPTILES			
Arizona chuckwalla *Sauromalus ater*	USFWS-SC	Predominantly found near cliffs, boulders, or rocky slopes, where they use rocks as basking sites and rock crevices for shelter (AGFD 2009).	**No suitable** habitat at the Ocotillo Site. The species occurs at Papago Park and Hayden Butte Preserve.
BIRDS			
Great egret *Ardea alba*	WSC MBTA	Occupies marshes, swampy woods, tidal estuaries, lagoons, mangroves, streams, lakes, rivers and ponds; also found in fields and meadows (AGFD 2002a).	**No suitable habitat** at the Ocotillo Site. The species occurs regularly at Tempe Town Lake and could occur at Karsten Golf Course, small urban lakes, and along the Salt River.
Snowy egret *Egretta thula*	WSC MBTA	Occurs in marshes, lakes, ponds, lagoons, mangroves, and shallow coastal habitats (AGFD 2002b).	**No suitable habitat** at the Ocotillo Site. The species occurs regularly at Tempe Town Lake and could occur at Karsten Golf Course, small urban lakes, and along the Salt River.
Peregrine falcon *Falco peregrinus americanus*	USFWS-SC WSC MBTA	Usually found in rugged mountainous areas with cliffs near an abundant avian prey base for a source of food. Also roosts in some urban areas with tall buildings where pigeons or doves are plentiful (AGFD 2002c).	**No suitable habitat** at the Ocotillo Site. The species occurs infrequently at Tempe Town Lake.
Bald eagle *Haliaeetus leucocephalus*	USFWS-SC WSC MBTA BGEPA	Wintering habitat has an adequate food supply, open water with tall trees, or other features that offer a commanding view of an area. Typically roosts or nests in low elevation areas with mature trees in riparian forests (AGFD 2011a).	**No suitable habitat** at the Ocotillo Site. The species occurs regularly during winter months at Tempe Town Lake and nests about 1.5 miles east of the Ocotillo Site (just above Tempe Town Lake).
Belted kingfisher *Megaceryle alcyon*	WSC MBTA	Found in association with a wide variety of water bodies including: rivers, brooks, ponds, lakes, coasts, streams, tidal creeks, mangroves, swamps, and estuaries (AGFD 2007).	**No suitable habitat** at the Ocotillo Site. The species occurs regularly at Tempe Town Lake. Potential foraging habitat occurs at Karsten Golf Course or other small urban lakes.
MAMMALS			
California leaf-nosed bat *Macrotus californicus*	USFWS-SC WSC	Found in arid Sonoran desertscrub habitats with roost sites that include caves, mines, and rock shelters. Forages through matrix of shrubs, often gleaning prey from shrubs or ground (AGFD 2001).	**No suitable habitat** at the Ocotillo Site. Potential foraging habitat occurs in Papago Park and Hayden Butte Preserve.

Species	Status	Habitat Requirements	Habitat Suitability
Greater western mastiff bat *Eumops perotis californicus*	USFWS-SC WSC	Forages in upper and lower Sonoran desert scrub often near water or at high altitudes. Roost habitat is in cliffs with tight crevices (AGFD 2002d).	**No suitable habitat** at the Ocotillo Site. Potential foraging habitat occurs at Tempe town lake, Karsten Golf Course, or above Papago Park and Hayden Butte Preserve.
Cave myotis *Myotis velifer*	USFWS-SC	Inhabits arid lower elevations, usually around high cliffs and rugged rock outcrops from desertscrub to mid-elevation woodlands. Roosts in caves, mines, and human built structures during the day (AGFD 2002e).	**No suitable habitat** at the Ocotillo Site. Roosting and foraging habitat available in Papago Park, Hayden Butte Preserve, and Arizona State University. Individuals could forage over Tempe Town Lake, the Salt River, or Karsten Golf Course.
Western yellow bat *Lasiurus xanthinus*	WSC	Associates with planted palm trees in urbanized areas, riparian woodlands and forests, and desert environments with tree-like yucca – usually near a water source (AGFD 2011b).	**No suitable habitat** at the Ocotillo Site. Roosting and foraging habitat available in much of the remaining study area.
PLANTS			
Desert barrel cactus *Ferocactus cylindraceus*	ANPL-SR	Grows on gravelly or rocky hillsides, canyon walls, alluvial fans, and wash margins in the Mohave and Sonoran deserts, on igneous and limestone substrates. Collected on Lycium, Larrea flat. Elevation: 200 to 2,900 feet (61 to 885 meters).	**No suitable habitat** at the Ocotillo Site. Potential habitat occurs in Papago Park, Hayden Butte Preserve, and Rio Salado Park.

NOTES: Agency or Law: USFWS = U.S. Fish and Wildlife Service; MBTA = Migratory Bird Treaty Act; BGEPA = Bald and Golden Eagle Protection Act; ANPL = Arizona Native Plant Law.
Status Definitions: **USFWS:** SC = species of concern; **State of Arizona:** WSC = wildlife of special concern; SR = salvage restricted plant.

IMPACT ASSESSMENT

APS proposes to decommission two steam generators and install five new gas turbine generators (GTs) at the Ocotillo Site. The water used for power generation would come from three existing, permitted wells, two at the Ocotillo Site and one about 0.5-mile away. The Project would occur within the SE ¼ of Section 14, T1N, R4E (Gila-Salt River Meridian). The natural gas pipeline (from the existing metering station to the GTs) and new Generation Interconnections necessary for the Project would be installed within the boundaries of the Ocotillo Site; no disturbance is anticipated to lands outside the Ocotillo Site.

The Ocotillo Site is a currently industrialized area and does not have habitat to support special status species or species of concern. Table C-1 describes the habitat requirements for these species and the known or likely areas where these species could occur near the Ocotillo Site. These species occur in native communities and urban areas adjacent to the Ocotillo Site, which would not be impacted by the Project, because ground-disturbing impacts would be confined to the Ocotillo Site itself. Operations would remain similar to current operations, and native habitats, plants, and wildlife species outside the Ocotillo Site would not experience other additional impacts.

The species described in Table C-1 could utilize habitats that are collectively near the Ocotillo Site at Tempe Town Lake; the Salt River; Papago Park; Hayden Butte Preserve; or, to a limited extent, golf courses and small urban lakes. However, habitats in these areas would not be disturbed by the Project. The bird or bat species described in Table C-1 could incidentally fly over the Ocotillo Site, with a risk of colliding with one of the five 85-foot tall exhaust stacks or Generation Interconnections proposed for the

Project. However, these additional features would occur in the industrial footprint, which would not have attractive habitat for these species or most birds protected under the MBTA. Also this would not appreciably increase the total infrastructure in the study area that poses the same or similar risks. The impact from the additional vertical structures would be negligible.

The new gas turbines would be installed on the west side of the Ocotillo Site; this area has been previously disturbed and holds abandoned tanks that would be removed. The construction footprint at the Ocotillo Site is in a fully industrialized area and all infrastructure upgrades and construction would be within this area that has no habitat value for special status species. Habitats outside the Ocotillo Site would not be impacted from construction, and special status species habitat, populations, or individuals outside the Ocotillo Site would not be impacted by the Project.

An unlined, industrial pond occurs about 780 feet east of the northernmost of the abandoned tanks that would be removed within the construction footprint (Lat/Lon location: 33.426°N, 111.914°W). Water in this industrial pond primarily comes from rain water and wash down around the steam units. This industrial pond would be removed from service after the old steam generators are shut down, which would coincide with the commercial operations of the new GTs.

There is some wetland vegetation that occurs along the margins of this pond that could provide breeding, foraging, or roosting habitat for some MBTA species. However, this habitat is not of sufficient quantity or quality to be a likely attractant for the special status bird species listed in Table C-1. Common migratory bird species like red-winged blackbirds (*Agelaius phoeniceus*), yellow-headed blackbirds (*Xanthocephalus xanthocephalus*), killdeer (*Charadrius vociferus*), great-tailed grackles (*Quiscalus mexicanus*), and puddle ducks – primarily mallards (*Anas platyrhynchos*), and other urban species would be the most likely ones to utilize this habitat. Upon removal, any birds that use this pond or its fringe of vegetation would be forced to move, but there are larger and more suitable habitat types of wetland vegetation and surface water in the immediate vicinity of the Ocotillo Site to which use could shift.

Water used for the operational phase of the Project is from a secured existing source, and discharge water would initially be treated onsite before being sent for further treatment through the City of Tempe sewer system. Water use and treatment from the operation of the power plant would not affect the quantity or quality of available surface water in habitats or wetlands that could support special status species outside the Ocotillo Site. Other aspects of future operation would be similar to current operations of the Power Plant, and there would be no impact to special status species habitats or populations residing in the surrounding study area outside the Ocotillo Site.

Project notices were sent to the Arizona Ecological Services Office of the USFWS and to AGFD. In its response, the USFWS noted the Project being about 0.5 mile from Tempe Town Lake and described the lake as supporting aquatic and riparian habitat for organisms such as fish, bald eagles, and peregrine falcons. The agency also provided a statement to remind the proponent that the Project must comply with the provisions of the MBTA and BGEPA. There are no anticipated impacts to species protected under either act, due to the Project occurring completely on an industrial site with extensive disturbance. Specific to the bald eagle, a nest site is located near Tempe Town Lake at a distance of about 1.5 miles from the Ocotillo Site; this would not be impacted by the Project, and foraging and perching habitat for the species at Tempe Town Lake would not be altered by the Project. AGFD had no specific concerns about the Project. The correspondence with these agencies is included in Exhibit J.

Mitigation

No extensive mitigation is necessary to lessen or eliminate impacts to special status species or migratory birds. The required Generation Interconnections should follow industry standard guidelines to protect perching raptors and other birds, and conductors should include aerial markers to reduce the likelihood of collision. Decommissioning the industrial pond, if any specific disturbance (including filling) is necessary, should occur outside the nesting season (generally February through June) to protect migratory birds that may nest in that area.

CONCLUSION

Within the surrounding study area, the biotic environment has experienced high levels of disturbance, with urban development in nearly the entire area. The few places that retain mostly native characteristics include Papago Park, Hayden Butte Preserve, and Rio Salado Park. Tempe Town Lake and the Salt River also have habitat values for native wildlife, particularly species associating with aquatic environments or wetlands. Karsten Golf Course and other local golf courses near the Ocotillo Site also have potential habitat for waterfowl and other migratory birds. The Ocotillo Site is a highly disturbed industrial area; however, there is a small, unlined, industrial pond and scattered native shrubs in a small part of the site. This area occurs about 780 feet east of the northernmost of the abandoned tanks that are proposed for removal as part of this Project. When the unlined industrial pond outside the construction footprint is taken out of service, any migratory birds that utilize this feature would have to move to available habitats outside the Ocotillo Site that are larger and possibly more suitable.

Local populations of special status species, species of concern, or migratory birds would not be forced from currently occupied areas outside the Ocotillo Site, because the Project would be constructed within the existing disturbed, industrial footprint of the power plant. Future operations would not change significantly from existing ones and there are no anticipated additional impacts on special status species or their habitats during this phase. None of the actions associated with the proposed Project would result in impacts that could necessitate listing these species at a state or federal level, and there would be no effect on federally listed species or designated critical habitat and no impact to candidate or species proposed for federal listing, because none of these are likely to occur in either the Ocotillo Site or surrounding study area due to a lack of suitable habitat.

REFERENCES

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_____. 2002a. Great egret (*Ardea alba*). Unpublished abstract compiled and edited by the Heritage Data Management System, Arizona Game and Fish Department, Phoenix, Arizona. 5 pp.

_____. 2002b. Snowy egret (*Egretta thula*). Unpublished abstract compiled and edited by the Heritage Data Management System, Arizona Game and Fish Department, Phoenix, Arizona. 5 pp.

_____. 2002c. American peregrine falcon (*Falco peregrinus americanus*). Unpublished abstract compiled and edited by the Heritage Data Management System, Arizona Game and Fish Department, Phoenix, Arizona. 6 pp.

_____. 2002d. Greater western mastiff bat (*Eumops perotis californicus*). Unpublished abstract compiled and edited by the Heritage Data Management System, Arizona Game and Fish Department, Phoenix, Arizona. 6 pp.

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EXHIBIT D – BIOLOGICAL RESOURCES

Arizona Revised Statutes ("ARS") §40-360 et seq. established the Power Plant and Transmission Line Siting Committee in 1971. ARS §40-360.06(A)(2) stipulates "fish, wildlife, and plant life and associated forms of life on which they are dependent" are among the factors the Siting Committee must consider in reviewing CEC applications. As stated in Arizona Corporation Commission Rules of Practice and Procedure R14-3-219:

> "*List the fish, wildlife, plant life and associated forms of life associated with the vicinity of the proposed sites or route and describe the effects, if any, other proposed facilities will have thereon.*"

RESOURCE OVERVIEW

The Ocotillo Modernization Project ("Project") is proposed on industrial lands within the SE ¼ of Section 14, T1N, R4E (Gila-Salt River Meridian). The "project area" is defined as the footprint of the Ocotillo Power Plant ("Ocotillo Site"). The "study area" for this exhibit is defined as lands within 3 miles of the Ocotillo Site. The study area was determined through a query within the Arizona Game and Fish Department ("AGFD") online project review system, which standardizes the potential impact area by the type of project and a configuration of the project area. This study area is consistent with that used for Exhibit C (Special Status Species).

The study area is located in the northern Sonoran Desert biotic region and southern portion of the Basin and Range physiographic province. It is primarily south of the Salt River in Tempe, Arizona. Despite the scarce, erratic, and unreliable precipitation patterns and the high summer temperatures, the Sonoran Desert supports one of the most diverse floras and faunas in the United States and is the most biologically diverse of the North American deserts. Historically, the study area would have been dominated by native desert scrub vegetation. However, in its current state, the study area has a highly reduced potential to support native animals and plants due to the high degree of urbanization. The Ocotillo Site is industrialized with limited useable habitat for fish, wildlife, and plant resources.

Overall, the study area's biotic environment has experienced high levels of disturbance that has converted native desert to various urban uses and agricultural fields. Remnant native desert ecosystems occur along parts of the Salt River, at Papago Park, Rio Salado Park, and within Hayden Butte Preserve. Tempe Town Lake, Karsten Golf Course, other local golf courses, and parks have perennial surface water and some native plants that could support various species of native and non-native wildlife. The Ocotillo Site is a highly disturbed industrial area; however, there is a small, unlined, industrial pond and scattered native shrubs in a small part of the Ocotillo Site. This area occurs about 780 feet east of the northernmost of the abandoned tanks that are proposed for removal as part of this Project.

INVENTORY

Species and habitat information were gathered from published and peer-reviewed resources. Aerial imagery, Southwest ReGAP landcover data (U.S. Geological Survey ["USGS"] National GAP Analysis Program 2004), soils, and topography data also were reviewed with the aid of GIS to characterize local conditions and the locations of biologically valuable areas. Scientific literature, AGFD Heritage Data Management System (AGFD 2013), and NatureServe Explorer (Nature Serve 2013) were utilized to provide additional, specific information about biological resources of the study area. Based on this information, potential impacts on biological resources were identified and analyzed according to the amount and type of disturbance to vegetation types or land cover types that would result from the Project. A vegetation type is defined by the dominant plant species and primary growth form in a locality.

Inventory results and the possible impacts on biological resources are presented in the sections that follow. Vegetation types or land cover types are described first, followed by a narrative of wildlife typically associated with each of these.

Agricultural Lands and Urban Areas

Agricultural lands occupy about 570 acres on the Salt River Indian Reservation in the northeastern part of the study area. In this same overall area, about 300 acres of fallow croplands appear to have been out of production for more than 15 years and have begun to revert back to desertscrub. These fallow areas appear to be brush-cut periodically. There are no agricultural lands within the Ocotillo Site.

Urban areas dominate most of the study area. These include urban development for housing, commercial, and industrial uses. This analysis includes urban parks and golf courses under urban areas. Golf courses include Karsten Golf Course that is adjacent to the Ocotillo Site, Rio Salado Golf Course, and Rolling Hills Golf Course. Urban vegetation is primarily exotic with some native species planted as ornamentals. Golf courses and urban parks in the study area often have small fragmented areas of disturbed native desert scrub or scattered native trees such as palo verde planted as ornamentals. These also have small lakes or other types of surface water that can attract native wildlife. The Ocotillo Site is almost entirely industrial.

The proposed construction footprint itself is entirely industrial with a presently unused area near it that has ruderal native shrubs and an unlined, industrial discharge pond. Water in this industrial pond primarily comes from rain water and wash down around the steam units. This industrial pond and the surrounding undeveloped land occurs about 780 feet east of the northernmost of the abandoned tanks that will be removed within the construction footprint (Lat/Lon location: 33.426°N, 111.914°W). This industrial pond would be removed from service after the old steam generators are shut down, which would coincide with the commercial operations of the new gas turbine generators (GTs).

Wildlife of Agricultural Lands and Urban Areas

The composition of wildlife found on agricultural lands and in urban areas within the study area typically would be a subset of species found in native habitats. Habitat generalists would be favored over specialists, and bird species would typically be the richest group because these lands would offer favorable resources for winter migrants as well as breeding residents. These areas also would have a large number of exotic wildlife species that could typically outnumber the native species. Native shore birds, waterfowl, and other native birds may congregate around the small urban lakes at golf courses and urban parks.

Creosotebush-Bursage Desertscrub Vegetation

Creosotebush-bursage desertscrub (creosote scrub) does not occur within the Ocotillo Site but is one of the common native vegetation types in the surrounding study area. It forms in broad valleys, lower bajadas, plains, and low hills in the Chihuahuan, Mojave, and lower Sonoran deserts where soils are deep, arid, and fine-textured (NatureServe 2013). This form of desertscrub is characterized by a sparse to moderately dense layer (2 to 50 percent cover) of small-leaved, drought-tolerant, shrubs and broad-leaved deciduous herbs (NatureServe 2013). Shrubs tend to be widely spaced with little grass or other herbaceous cover in between. Creosotebush (*Larrea tridentata*), white bursage (*Ambrosia dumosa*), or triangle-leaf bursage (*Ambrosia deltoidea*) are the typical dominants, but a variety of other shrubs, dwarf-shrubs, and cacti can be present or form sparse understories (NatureServe 2013). Other typical species include Mexican Mormon tea (*Ephedra trifurca*), senna (*Senna* sp.), and galleta grass (*Pleuraphis rigida*) (NatureServe 2013).

Creosote scrub grows in nearly uniform stands at various densities that fluctuate according to the available water in the study area. Along the Salt River, portions of this vegetation type are dominated by halophytic (salt tolerant) plants, typically dominated by various types of saltbush (*Atriplex* spp.). Creosote scrub is most common along the bed and bank of the Salt River, but it also occurs next to some agricultural areas within the Salt River Pima-Maricopa Indian Community, in low-lying areas at Papago Park, and at Rio Salado Park. This vegetation type does not occur within the Ocotillo Site.

Wildlife of Creosotebush-Bursage Desertscrub Vegetation

Amphibians

Amphibians potentially occurring in this vegetation type in the study area would include the Sonoran Desert toad (*Incilius alvarius*) and Couch's spadefoot toad (*Scaphiopus couchii*). The number of amphibians is limited because of the lack of surface water in this vegetation type.

Reptiles

A number of reptiles typically inhabit this vegetation type in the study area. Characteristic species that could occur in the study area include the long-nosed leopard lizard (*Gambelia wislizenii*), desert iguana (*Dipsosaurus dorsalis*), tiger whiptail (*Aspidoscelis tigris*), desert horned lizard (*Phrynosoma platyrhinos*), glossy snake (*Arizona elegans*), nightsnake (*Hypsiglena chlorophaea*), common king snake (*Lampropeltis getula*), Sonoran whipsnake (*Masticophis bilineatus*), gopher snake (*Pituophis catenifer*), sidewinder (*Crotalus cerastes*), and Mojave rattlesnake (*Crotalus scutulatus*).

Birds

Widespread generalist birds like the turkey vulture (*Cathartes aura*), red-tailed hawk (*Buteo jamaicensis*), American kestrel (*Falco sparverius*), mourning dove (*Zenaida macroura*), northern mockingbird (*Mimus polyglottos*), and western meadowlark (*Sturnella neglecta*) could be found in this vegetation type in the surrounding study area. Likely arid habitat specialists in the study area would include the white-winged dove (*Zenaida asiatica*), greater roadrunner (*Geococcyx californianus*), western kingbird (*Tyrannus verticalis*), Say's phoebe (*Sayornis saya*), and black-throated sparrow (*Amphispiza bilineata*) (Birds of North America, accessed 2013).

Mammals

Typical mammals in these habitats within the study area include the desert cottontail (*Sylvilagus audubonii*), black-tailed jackrabbit (*Lepus californicus*), round-tailed ground squirrel (*Spermophilus tereticaudus*), Botta's pocket gopher (*Thomomys bottae*), little pocket mouse (*Perognathus longimembris*), Sonoran desert pocket mouse (*Chaetodipus penicillatus*), cactus mouse (*Peromyscus eremicus*), javelina (*Tayassu tajacu*), and coyote (*Canis latrans*). About 15 species of bat could utilize this vegetation type to some extent within the surrounding study area (summary derived from Hoffmeister 1986).

<u>Sonoran Paloverde-Mixed Cacti Desertscrub Vegetation</u>

Sonoran paloverde-mixed cacti desertscrub is the typical vegetation type in hilly to mountainous terrain and foothills or along washes with a rocky substrate. This vegetation type does not occur within the Ocotillo Site but occurs in the surrounding study area. This vegetation forms on coarse, gravelly to rocky soils and outcrops (Natureserve 2013). Creosotebush and bursage are found in this vegetation type (NatureServe 2013); however, blue paloverde (*Parkinsonia florida*), foothill paloverde (*Parkinsonia* *microphylla*), saguaro (*Carnegiea gigantea*), and ocotillo (*Fouquieria splendens*) are the definitive overstory species that are most common in the study area. Other leguminous trees and succulents like desert ironwood (*Olneya tesota*), velvet mesquite (*Prosopis velutina*), and cacti (e.g., *Opuntia* sp., *Cylindropuntia* sp., *Ferocactus* sp.) can be observed in this vegetation type (NatureServe 2013). This vegetation type also typically has a relatively higher diversity of plants and animals compared to creosote scrub.

Sonoran paloverde-mixed cacti desertscrub grows along the bed and bank of the Salt River. It also is common in elevated terrain at Papago Park, Hayden Butte Preserve, and a small part of Rio Salado Park. This vegetation type does not occur within the Ocotillo Site.

Wildlife of Sonoran Paloverde-Mixed Cacti Desertscrub Vegetation

The usual wildlife species found in this vegetation type include widespread generalists, rock-dwelling specialists, and cavity nesters. Some of these species may either migrate through the study area or partially utilize transitional areas between upland and lowland desertscrub vegetation.

Reptiles

Typical reptiles that could occur in this vegetation type within the surrounding study area may include the western banded gekko (*Coleonyx variegates*), Gila monster (*Heloderma suspectum*), long-nosed leopard lizard, chuckwalla (*Sauromalus ater*), desert spiny lizard (*Sceloporus magister*), tiger whiptail, nightsnake, common king snake, gopher snake, and western diamondback (*Crotalus atrox*) (Brennan and Holycross 2006). There is no suitable habitat for the chuckwalla at Rio Salado Park or along the Salt River.

Birds

Birds possibly found in this vegetation type within the study area include the turkey vulture, golden eagle (*Aquila chrysaetos*), red-tailed hawk, American kestrel, common barn owl (*Tyto alba*), great horned owl (*Bubo virginianus*), western meadowlark (*Sturnella neglecta*), Harris' hawk (*Parabuteo unicinctus*), Gambel's quail (*Callipepla gambelii*), white-winged dove, greater roadrunner, lesser nighthawk (*Chordeiles acutipennis*), western kingbird, ash-throated flycatcher (*Myiarchus cinerascens*), Say's phoebe, cactus wren (*Campylorhynchus brunneicapillus*), curve-billed thrasher (*Charadrius vociferus*), phainopepla (*Phainopepla nitens*), pyrruloxia (*Cardinalis sinuatus*), verdin (*Auriparus flaviceps*), black-tailed gnatcatcher (*Polioptila melanura*), black-throated sparrow (*Amphispiza bilineata*), and Scott's oriole (*Icterus parisorum*) (Birds of North America, accessed 2013).

Mammals

Mammalian species that could occur in this vegetation type within the surrounding study area include the desert cottontail, black-tailed jackrabbit, Harris' antelope ground squirrel (*Ammospermophilus harrisii*), rock pocket mouse (*Chaetodipus intermedius*), Merriam's kangaroo rat (*Dipodomys merriami*), white throated woodrat (*Neotoma albigula*), cactus mouse, collared peccary, mule deer (*Odocoileus hemionus*), coyote (*Canis latrans*), and ringtail (*Bassariscus astutus*). About 18 species of bat could forage in this vegetation type or locate roost sites in mountainous terrain coincident with this vegetation (summary derived from Hoffmeister 1986). Other known roost sites for bats in the surrounding study area include the buildings and football stadium at Arizona State University and palm trees in urban areas.

<u>Wetlands and Open Water</u>

Wetland habitats in the surrounding study area include native and invasive wetland areas along the Salt River and around Tempe Town Lake. Smaller managed wetlands occur around some of the urban lakes. Open water occurs at Tempe Town Lake, the golf courses, intermittent stretches of the Salt River, and at some urban parks.

An unlined, industrial pond occurs about 780 feet east of the northernmost of the abandoned tanks that would be removed within the construction footprint. Water in this industrial pond primarily comes from rain water and wash down around the steam units. This industrial pond would be removed from service after the old steam generators are shut down, which would coincide with the commercial operations of the new GTs. There is some wetland vegetation that occurs along the margins of this pond. A small patch of ruderal native shrubs occurs in the vicinity of this pond, but these are not wetland plants.

Overstory plants typically found around desert wetlands in the region include Godding's willow (*Salix gooddingii*), arroyo willow (*Salix lasiolepis*), net-leaf hackberry *(Celtis laevigata var. reticulata*) mesquite (*Prosopis* spp.), palo verde, and salt cedar (*Tamarix* spp.). Dominant shrubs include arrow weed (*Pluchea sericea*), bush seepweed *(Suaeda moquinii*), and narrow-leaf willow (*Salix exigua*) (NatureServe 2013). Vegetation is dependent upon annual or periodic flooding and associated sediment scour and annual rise in the water table for growth and reproduction (NatureServe 2013).

Wildlife of Wetlands

Wildlife associated with wetlands could include a great variety of species, including native and introduced types. Commonly seen shorebirds, wading birds, and wetland associates along the Salt River include the red-winged blackbird (*Agelaius phoeniceus*), yellow-headed blackbird (*Xanthocephalus xanthocephalus*), green heron (*Butorides virescens*), black-crowned night heron (*Nycticorax nycticorax*), American coot (*Fulica americana*), American bittern (*Botaurus lentiginosus*), and Virginia rail (*Rallus limicola*). Numerous upland birds are often found in these habitats, because of the abundant food resources, lower temperatures, abundant shade, and available water. Some of the more common of these include the western tananger (*Piranga ludoviciana*), mourning dove, white-winged dove, western kingbird, Say's phoebe, great-tailed grackle (*Quiscalus mexicanus*), and black phoebe (*Sayornis nigricans*). These habitats also would be attractive foraging habitats for a number of bat species.

Expected ground dwelling species in or near these habitats include a number of lizard and mammal species. Common reptiles include the tiger whiptail lizard and long-nosed leopard lizard. Likely mammals that could inhabit these areas include the Arizona cotton rat (*Sigmodon arizonae*), striped skunk (*Mephitis mephitis*) raccoon (*Procyon lotor*), mule deer, and javelina.

It is expected that some native wildlife could use the industrial pond east of the construction footprint. Common species like redwing blackbirds, yellow-headed blackbirds, killdeer (*Charadrius vociferus*), great-tailed grackles, and puddle ducks – primarily mallards (*Anas platyrhynchos*), and other urban species would be the most likely ones to utilize this habitat.

IMPACT ASSESSMENT

APS proposes to decommission two steam generators and install five new GTs at the Ocotillo Site. The replacement generators would be installed and other work would occur on the western side of the Ocotillo Site. The water used for power generation and extra capacity would come from three existing, permitted wells, two at the Ocotillo Site and one about 0.5-mile away. The Project would occur within the SE ¼ of Section 14, T1N, R4E (Gila-Salt River Meridian). The natural gas pipeline (from the existing onsite metering station to the new GTs) and new Generation Interconnections necessary for the Project would be installed within the Ocotillo Site; no offsite disturbance would be anticipated.

The Ocotillo Site is currently industrialized and has little habitat to support wildlife. The unlined industrial pond, with a narrow wetland margin and native shrubs scattered nearby, lies about 780 feet east of the northernmost of the abandoned tanks. This area would not be disturbed or impacted construction of the Project. When the modernized power plant becomes operational, this industrial pond would be removed from service after the old steam generators are shut down, which would coincide with commercial operations of the new GTs. This area could be used by common urban wildlife, particularly native bird species, but it is of insufficient size or quality to be a major attractant for native wildlife. When taken out of service, wildlife would have to move to other available habitats outside the Ocotillo Site.

Other wildlife species that occur in native vegetation areas and urban areas adjacent to the Ocotillo Site would not be impacted by the Project, because all impacts would be confined to the Ocotillo Site itself. Operations would remain similar to current operations, and native habitats, plants, and wildlife species outside the Ocotillo Site would not experience additional impacts.

Water used for the operational phase of the Project is from a secured existing source, and discharge water would initially be treated on site before being sent for further treatment through the City of Tempe sewer system. Water use and treatment from the operation of the power plant would not affect the quantity or quality of available surface water in habitats outside the Ocotillo Site. Other aspects of future operation would be similar to current operations, and there would be no additional impacts to habitats or populations of plants or animals residing in the surrounding study area outside the Ocotillo Site.

There is some potential for birds to collide with exhaust stacks (85 feet tall) or Generation Interconnection towers or conductors that will be constructed as part of the Project. However, these additional features would occur in the industrial footprint, which would not have attractive habitat for most of these species. Also this would not appreciably increase the total infrastructure in the study area that poses the same or similar risks. The additional risk of collision would be negligible.

Project notices were sent to the Arizona Ecological Services Office of the USFWS and to AGFD. In its response, the USFWS noted the Project being about 0.5 mile from Tempe Town Lake and described the lake as supporting aquatic and riparian habitat for organisms such as fish, bald eagles, and peregrine falcons. The agency also provided a statement to remind the proponent that the Project must comply with the provisions of the MBTA and BGEPA. There are no anticipated adverse impacts to species protected under either act, due to the Project occurring on an industrial site with extensive disturbance. AGFD had no specific concerns about the Project. The correspondence from these agencies is included in Exhibit J.

Mitigation

No extensive mitigation is necessary to lessen or eliminate impacts to biological resources overall. The Project would have minimal impacts to biological resources. Generation Interconnections should follow industry standard guidelines for transmission lines to protect perching raptors and other birds, and conductors should include aerial markers to reduce the likelihood of collision. Decommissioning the industrial pond, if any specific disturbance (including filling) is necessary, should occur outside the nesting season (generally February through June) to protect migratory birds that may nest in that area.

CONCLUSION

Construction would occur only on previously disturbed industrial land at the power plant. Future operations would not significantly change and would introduce no additional impacts. Therefore, the Project is not anticipated to result in adverse impacts to plants or wildlife in the natural vegetation areas or urban habitats outside the Ocotillo Site. The fragment of vegetation and unlined industrial pond, and any potential wildlife that could utilize the “pond area” located at the Ocotillo Site would not be significantly impacted by construction of the Project. The pond would be taken out of service when the steam generators are decommissioned. Wildlife using this habitat would have to move to other available habitats outside the Ocotillo Site that are larger and possibly more suitable.

There would be no loss or alteration of existing habitat outside the Ocotillo Site, and local populations of wildlife would not be forced from currently occupied areas. There would be no anticipated injury or mortality of individuals. None of the actions associated with the Project would result in impacts that could necessitate listing wildlife species at a state or federal level.

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APPENDIX H.

Historic Preservation.

HISTORIC SITES AND STRUCTURES AND ARCHAEOLOGICAL SITES

Introduction and Summary of Assessment

Arizona Public Service Company ("APS") began constructing the Ocotillo Power Plant ("Power Plant") in March 1958 and completed the plant and put it into operation in 1960. When the plant was built there was no regulatory requirement to consider impacts on historical and archaeological resources. Pursuant to the ACC Rules of Practice and Procedure R14-3-219 that implement ARS §40-360 et seq., APS inventoried and assessed potential effects of the proposed modernization of the Ocotillo Power Plant on historic sites and structures and archaeological sites. The assessment also supports ACC compliance with the 1982 State Historic Preservation Act (ARS §41-861 et seq.), which requires state agencies to consider impacts of their programs on historic properties listed in or eligible for the Arizona Register of Historic Places ("Arizona Register"). [The criteria for inclusion in the Arizona Register are identical to those for the National Register of Historic Places ("National Register").]

The Power Plant is on a 126-acre parcel of land owned by APS, but construction activities that might disturb archaeological and historical resources would be mostly limited to about 15.8 acres, in the western part of the parcel where three large fuel oil storage tanks would be removed and five new gas turbines would be built. Construction of an internal access road and installation of new Generation Interconnection structures would disturb additional small areas. Another 10.4 acres would be used for temporary construction offices, materials laydown, and vehicle parking, but that area was previously disturbed and those uses are unlikely to have any potential to disturb archaeological and historical resources. Removal of the two steam units and associated cooling towers will disturb additional areas that were highly disturbed when the units were built.

The assessment concluded that:

- Although the Power Plant is of historic age, it lacks historical significance that warrants preservation and it is not eligible for the Arizona Register. Twenty-three historic districts, buildings, and structures previously listed in or determined to be eligible for the Arizona Register/ National Register are located within 1 mile of the Power Plant, and 87 more are within 1 to 2 miles. The proposed modernization is not expected to have any adverse visual or other indirect impacts on those properties.
- Prehistoric Hohokam artifacts (mostly potsherds) are scattered across the earthen berms of the retention basin around three large abandoned fuel oil storage tanks in the western part of the power plant parcel where the proposed new gas turbines would be constructed. Archaeological testing identified one buried feature—a small prehistoric Hohokam irrigation ditch that, along with the results of other prior archaeological investigations in nearby areas, indicates that at times between approximately A.D. 750 and 1450 the Hohokam farmed the Salt River floodplain where the Ocotillo Power Plant was built. The artifacts on the retention basin berms might be remnants of field activity areas or possibly field houses that were disturbed when the fuel oil tanks were installed. APS plans to conduct more extensive and deeper archaeological testing to determine if there are other buried features at the site, which was designated in the Arizona State Museum site survey system as AZ U:9:311(ASM). Further study of the artifacts on the berms of the retention basin is unlikely to yield important information because the artifacts are in such a disturbed context, but further investigation of the buried canal feature might yield important information about the prehistoric Hohokam occupation of the Phoenix Basin, which would make the site eligible for the Arizona Register. Because the canal feature is in the northwest corner of the power plant parcel, it might not be disturbed by the proposed power plant modernization. If the canal feature cannot be avoided or if further testing identifies additional intact archaeological deposits and features, APS will, in consultation with the State Historic Preservation Office

(“SHPO”) and other interested parties, develop and implement a plan to recover and preserve artifacts and information to mitigate the impacts of the proposed power plant modernization.

This exhibit summarizes the information on which those conclusions are based. That information was compiled by the three attached archaeological and historical studies that APS sponsored:

- *Cultural Resource Records Review and Archaeological Monitoring of Geotechnical Investigations at the Ocotillo Power Plant, Tempe, Maricopa County, Arizona*, 2013, URS Corporation, Phoenix, Arizona (Attachment E-1).
- *Ocotillo Power Plant District, State of Arizona Historic Property Inventory Form*, 2013, URS Corporation, Phoenix, Arizona (Attachment E-2).
- *Archaeological Testing at the Ocotillo Power Plant, Tempe, Maricopa County, Arizona*, 2014, URS Corporation, Phoenix, Arizona (Attachment E-3).

Inventory Methods

The identification of historic sites and structures and archaeological sites in the vicinity of the project area focused on resources listed in or eligible for the Arizona Register/National Register. To be eligible for the Arizona Register, districts, sites, buildings, structures or objects must be 50 years old (unless they have special significance) and have significance in the contexts of national, state, or local history, architecture, archaeology, engineering, or culture. They also must possess sufficient integrity of location, design, setting, materials, workmanship, feeling, or association to convey their historical significance, and meet at least one of four criteria:

Criterion A: be associated with an event that made a significant contribution to the broad patterns of history

Criterion B: be associated with the life of a historically important person

Criterion C: embody a distinctive characteristic of a type, period, or method of construction, represent the work of a master, possess high artistic value, or represent a significant and distinguishable entity whose components may lack individual distinction

Criterion D: have yielded or are likely to yield important prehistoric or historic information (Arizona Administrative Code, Title 12, Chapter 8, Article 3, R12-8-302)

The assessment of potential effects on historic sites and structures and archaeological sites was based on

- a record and literature review to identify information about prior studies and recorded archaeological and historical resources
- an evaluation of the historic significance of components of the Power Plant that are more than 50 years old
- archaeological monitoring of geotechnical borings
- archaeological testing

Information about prior cultural resource studies and cultural resources recorded within the power plant parcel and an area extending 1 mile around the parcel was compiled and mapped in a geographic information system database. Because modifications of the Power Plant might have potential indirect impacts on historic buildings and structures beyond 1 mile, additional information about properties listed in or evaluated as eligible for the Arizona Register, National Register, and Tempe Historic Property

Register ("Tempe Register") was compiled for an area extending between 1 and 2 miles from the power plant parcel.

Digital data were obtained from the AZSITE Cultural Resource Inventory, which is a geographic information system database that includes records of the AZSITE Consortium members (Arizona State Museum, Arizona State University ["ASU"], Museum of Northern Arizona, and SHPO), and other participating agencies such as the Bureau of Land Management. The AZSITE database includes information about properties listed in the Arizona Register and National Register. Records at ASU were checked for additional information that might not have been included in the AZSITE database. The Tempe Historic Preservation Office website and listings of the Tempe Register were checked as well. Historical maps and aerial photographs were examined for indications of potential unrecorded historical resources, and selected reports of prior studies were reviewed.

The Power Plant was visited in October 2013 to record historical components of the plant, and research was conducted to document the history of the plant. Archaeological fieldwork included monitoring of geotechnical borings in June and July 2013, and archaeological testing in November and December 2013.

Cultural History

To provide a context for evaluating the inventoried archaeological and historical resources, the cultural history of south-central Arizona is briefly summarized in this section. The history of the human occupation of the region can be divided into numerous periods that reflect changing adaptations and lifeways over approximately 14,000 years, including the Paleoindian (12,000 to 8500 B.C.), Archaic (8500 to 1500 B.C.), Late Archaic/Early Agricultural (1500 B.C. to A.D. 50), Early Ceramic (A.D. 50 to 450), Hohokam (A.D. 450 to 1450), protohistoric (A.D. 1450 to 1539), Spanish (1539 to 1821), Mexican (1821 to 1848/1854), and American (post-1848/1854) periods.

Evidence of the Paleoindian and Archaic hunting and gathering cultures that occupied the region for approximately 10,000 years is sparse in the Salt River Valley. As early as 2000 B.C. or even earlier, some groups in the region began to supplement their foraging subsistence strategies by growing domesticated plants such as maize, beans, and squash. As societies around the world adopted a sedentary agricultural way of life, they typically experienced a "Neolithic revolution" characterized by exponential population growth and increased economic, political, and social complexity. Regional populations do not seem to have experienced such a Neolithic revolution until the Hohokam culture developed around A.D. 450. The Hohokam occupation lasted for a millennium and is divided into four phases—Pioneer, Colonial, Sedentary, and Classic—based on changing styles of artifacts, house types, community structures, and burial customs. The Hohokam built the most extensive and sophisticated prehistoric irrigation systems in North America, and at their peak, tens of thousands of Hohokam lived in numerous villages throughout the valley and much of central and southern Arizona. The archaeological record of the Salt River Valley is dominated by remnants of the Hohokam occupation.

No native groups were residing in the Salt River Valley when the first European explorers arrived because the valley was contested territory between the Akimel O'odham (Pima), who resided in several villages along the Gila River to the south, and their enemies, the Yavapai, who lived to the north and west, and the Apache, who occupied uplands to the north and east. The Yuman-speaking Pee Posh (Maricopa), who migrated eastward along the lower Gila River, joined the Akimel O'odham in the mid-nineteenth century.

During the Spanish colonial era, De Niza and Coronado led expeditions through southeastern Arizona in 1539 and 1540, but Spanish colonization of Arizona began much later. In the late 1600s, Father Eusebio Kino established four missions in southern Arizona, but Spanish settlement never expanded north of the Tucson area, except for a missionary effort among the Hopi from 1629 to 1680 and a brief mission to the west along the lower Colorado River in 1780 and 1781. Spanish rule of the area ended with the Mexican Revolution in 1821, but Hispanic settlers continued to live much as they had although the inability of the newly independent government to continue the Spanish policy of issuing food rations to Apaches led to renewal of conflicts.

At the end of the War with Mexico in 1848, Mexico ceded much of what is now the American Southwest to the United States, and the United States acquired more area south of the Gila River with the ratification of the Gadsden Purchase in 1854. The 1860s brought a mining boom that ended the area's relative isolation. To control Apache raiding, the U.S. Army established Fort McDowell along the lower Verde River in 1865, and within a decade, most of the resisting groups had surrendered and been relocated to reservations. The Yavapai tried to avoid the new settlers, but eventually were also drawn into the conflict and skirmishes continued until 1872, when the Yavapai suffered a devastating defeat at Skull Cave. The Yavapai were transferred to a reservation at Rio Verde and were subsequently moved to the San Carlos Apache Reservation until reservations were established for them in their own traditional territory.

The Army and miners created a market for food and supplies, and farmers and ranchers arrived soon after the soldiers and prospectors. Jack Swilling, with the help of other residents of Wickenburg, a mining community 50 miles northwest of the Salt River Valley, organized the Swilling Irrigating and Canal Company and in 1867 began excavating an irrigation canal amid remnants of Hohokam canals near the location of the modern Phoenix airport. The success of the Swilling canal soon brought other settlers to the valley, and the Phoenix townsite was laid out in 1870. Phoenix was incorporated in 1881 and grew to be a commercial and governmental center, but settlement of the Salt River Valley was based primarily on irrigation agriculture. Growth and prosperity led to the designation of Phoenix as the territorial capital in 1889. By 1910, Phoenix had a population of 11,150 and was the third largest city in the territory. Only Tucson and the Clifton/Morenci mining community were larger. By 1920 Phoenix had a population of 29,100 and had become Arizona's largest city. The tourism industry was launched in the 1920s, but agriculture continued to dominate the economy.

Like Phoenix, Tempe began as an agricultural community created by homesteaders moving into the area and developing canal systems among the remnants of long abandoned Hohokam canals on the south side of the Salt River. Charles T. Hayden established the Hayden Milling and Farming Ditch Company in November 1870, and began excavating a canal near Tempe Butte. William Kirkland and James McKinney also excavated a short irrigation ditch in 1870, and in 1871 they joined forces with Hayden and the Tempe Irrigating Canal Company (originally organized as the Hardy Irrigating Canal Company) to develop the first major historic-era canal system on the south side of the river.

In 1872, Hayden established a ferry crossing of the Salt River, built a store near Tempe Butte at the north end of what is today downtown Tempe, and a post office was established. Soon after, Hayden built a flour mill and more Anglo-American and Mexican-American settlers moved to the area. Located about 8 miles east of Phoenix and across the river, Hayden's Ferry became an important transportation and agricultural center. The name of the settlement was changed to Tempe in 1879. Several Hispanic barrio communities developed around Tempe, including an area just to the east known as East Tempe or Barrio San Pablo and later as Barrio al Centro. Tempe became a center of education for the territory in 1885 when the state legislature appropriated funds for the Territorial Normal School at Tempe. In 1887, a railroad between Phoenix and the Southern Pacific Railroad station at Maricopa was completed, passing through Tempe and strengthening its role as a node along the transportation corridor through the Salt River Valley.

Farmers near Tempe and throughout the Salt River Valley benefitted from a more reliable water supply and flood protection after Roosevelt Dam was completed in 1911, which proved to be a major factor in Arizona achieving statehood in 1912. From 1910 to 1930, Tempe grew much more slowly than Phoenix, with population increasing from 1,500 to 2,500. Agriculture dominated the economy of Tempe until after

World War II, when new industrial parks and high technology industries began to be developed, and the growing population after the war led to the building of new housing subdivisions. Tempe is now Arizona's eighth largest city with a population of more than 160,000, and is surrounded by numerous other cities that make up the Phoenix metropolitan area, which has a population of almost 4.3 million.

Record Review Results: Prior Cultural Resource Studies

The Euro-Americans who began to settle the Salt River Valley in the 1860s soon recognized evidence indicating prehistoric peoples had occupied the valley, and professional archaeological research was initiated as early as the 1880s. For more than a half century, a few professional and avocational archaeologists continued to map and investigate the ruins of major prehistoric villages and irrigation canal systems before they were masked by agricultural and then urban development.

In addition to reports and maps prepared by those early researchers, a records review identified 65 modern cultural resource studies conducted since the late 1950s within or overlapping the records review area (appended Table E-1). More than 60 percent of those studies, which were conducted primarily to address cultural resource management regulations, were completed since 2000. Only four of the studies were conducted within the power plant parcel, and all of those were surveys of very limited scope that together covered fewer than 2 acres in the southwest corner of the parcel. No archaeological or historical sites were identified, but the area had been highly disturbed by development prior to those surveys.

Record Review Results: Previously Recorded Archaeological Sites

A records review documented 15 archaeological sites recorded within 1 mile of the power plant parcel, but none were in the parcel (appended Table E-2). Nine of those sites are now considered part of the single large site of La Plaza/Barrio San Pablo, which includes remnants of a large Hohokam village and also the historic Barrio San Pablo and other barrios that developed east of the original Tempe townsite. The La Plaza/Barrio San Pablo site was previously evaluated as eligible for the Arizona Register/National Register under Criterion D for its potential to yield important information.

The prehistoric component of the La Plaza site has been mapped as covering a vast area about 0.6 mile wide and 1.6 miles long, but urban development has obliterated surface evidence and little is known about most of the site. Early researchers mapped three platform mounds probably used for community ceremonies at the site, indicating it was a major Hohokam village. Several archaeological excavations have been conducted at the site, primarily in conjunction with construction of facilities on the ASU campus and development of the Valley Metro light rail system. Although those investigations have been limited mostly to the northwestern part of the site, they have documented approximately a millennium of intensive Hohokam occupation along the southern margins of Tempe Butte, from the Pioneer through the Classic periods. Much of the southern and eastern parts of the large site probably were not permanent habitation areas, but were instead fields watered by irrigation canals that branched from the Salt River several miles upstream.

The Hohokam built the La Plaza village on the Mesa terrace, which is about 10 to 15 feet above the channel of the Salt River. The villagers farmed mostly on the Mesa terrace but had some fields on the lower Lehi terrace, which is the geologic floodplain that is only about 5 feet above the river channel. The power plant parcel is on the Lehi terrace, and the southern edge of the parcel is more than 500 feet north of the edge of the Mesa terrace and the boundary of the La Plaza site. The alignment of one of the major Hohokam irrigation canals that supplied water to La Plaza has been mapped as passing through the southern edge of the power plant parcel, but those maps often are imprecise and it is not known whether remnants of the relict canal are buried within the parcel.

Over the years, several archaeological sites were recorded on Tempe Butte, about 0.75 to 1.25 miles west of the Power Plant. Those sites have been consolidated in the AZSITE database as the Tempe Glyph site, AZ U:9:114(ASM), and the Terraced Butte site, AZ U:9:115(ASM), but they can be considered part of a large site encompassing virtually the entire butte. In 2011, approximately 59 acres of the butte owned by the City of Tempe were listed in the National Register under Criteria C and D, and the City designated that part of the butte as the Hayden Butte Preserve Park . A traditional Akimel O'odham song poem identifies Tempe Butte as the first stop on a mythic tale of a westward journey. The Akimel O'odham name for the butte (*oidbad duag*) is translated as dead field mountain and might be a reference to abandoned Hohokam fields around the butte.

Another Hohokam site about 1 mile southeast of the power plant parcel is named La Cuenca del Sedimento and designated AZ U:9:68(ASM). Investigations prior to construction of the Price Freeway (State Route 101L) interpreted that site as a Classic period farmstead or field house site adjacent to canals within the irrigation system that served several large Hohokam village sites to the south, including Los Muertos, one of the largest Hohokam village sites in the Salt River Valley.

Three other small archaeological sites have been recorded in the review area just south of the La Plaza site. Two Hohokam canals and a twentieth-century trash pit were identified at site AZ U:9:95(ASU). Features documented at site AZ U:9:281(ASM) included two Hohokam field houses, two canals, use surfaces, pits, two cremations (a subadult and a young adult), and an infant inhumation. Three trash-filled Hohokam pits, a fire pit, and an adobe puddling pit were documented at site AZ U:9:296(ASM), which also was interpreted as a field activity area.

Record Review Results: Previously Recorded Historic Districts, Buildings, and Structures

The records review identified 23 historic buildings, structures, and districts recorded outside the power plant parcel but within 1 mile (appended Table E-3). Nine of those properties are listed in the National Register. The closest are the Borden Milk Company Creamery and Ice Factory (now used as a brewery and restaurant) (listed under Criteria A and C) and the Elias-Rodriguez House (listed under Criterion C), which are about 0.1 and 0.4 mile to the south and southwest, respectively. Five others are almost 1 mile west of the power plant parcel, including four buildings (listed under Criterion C or Criteria A and C), which are within an ASU District that has been evaluated as eligible but not listed, as well as St. Mary's Church (listed under Criterion C) just north of the ASU District. The other building is the White Dairy Barn (listed under Criterion C) on Apache Boulevard, about 0.5 mile south of the power plant parcel. That barn, which is now used as a tavern, is also listed in the Tempe Register. The residential University Park District (listed under Criteria A and C) was developed between 1946 and 1956 about 1 mile southwest of the power plant parcel.

Eight other properties within 1 mile of the power plant parcel have been determined to be eligible for the National Register but have not been listed. The closest is the Creamery Branch railroad line (under Criterion A). A spur line from the Creamery Branch was used to deliver fuel oil to the Ocotillo Power Plant but the spur, along with the rest of the line, has been abandoned, and only a few segments of the track south of University Drive remain partially intact. The Phoenix Main Line of the Southern Pacific Railroad, which continues to be operated by Union Pacific and passes about 0.8 mile south of the power plant parcel, has been evaluated as eligible (under Criterion A).

The Tempe Canal has been evaluated as eligible (under Criterion A) as part of the Salt River Project system, but most of the canal near the power plant parcel has been buried in pipe. An open segment about 0.2 mile south of the power plant parcel is listed in the Tempe Register and the Bureau of Reclamation and Salt River Project have designated it for preservation as an open ditch.

The Arizona Department of Transportation has evaluated the multiplexed U.S. Highway 60/70/80/89, as a component of the historic state highway system developed between statehood in 1912 and 1955, as eligible (under Criterion D). A segment of the historic highway alignment, designated as Apache Boulevard, is about 0.5 mile south of the power plant parcel. A multi-property set of six buildings along the alignment also have been evaluated as eligible for the National Register (under Criterion A) because of their association with automobile tourism.

The ASU men's gym has been evaluated as eligible (under Criterion C) and the ASU District within which the gym is located has been evaluated as eligible (under Criteria A and C). The gym and district are almost 1 mile west of the power plant parcel. Marlatt's Garage, a commercial building built in 1922 and evaluated as eligible (under Criteria A and C), is about 0.2 mile south of the power plant parcel.

Two residential subdivisions are listed in the Tempe Register as historic districts. Borden Homes, developed between 1947 and 1957, and Tomlinson Estates, developed between 1950 and 1953, are about one-fourth to one-third mile south of the power plant parcel. The Tempe Historic Preservation Office has identified four other post-World War II subdivisions as warranting further evaluation as candidates for the Tempe Register. Those include Carlson Park, about 0.2 mile south of the power plant parcel, and Hudson Manor, Hudson Park, and University Heights, which are about 0.5 to 0.9 mile from the power plant parcel. An adobe house and outbuilding, reportedly constructed around 1906, were recorded as AZ U:9:269(ASM) about 0.5 mile southwest of the power plant parcel, but those buildings were subsequently demolished.

An additional 87 historic resources listed in or evaluated as eligible for the National Register and Tempe Register are located between 1 and 2 miles from the power plant parcel (appended Table E-4). Almost all of those are on the ASU campus or in the historic core of Tempe west of the power plant parcel. One of those properties is a historic district and 30 are individual properties listed in the National Register, and 8 other individual properties are listed in the Tempe Register. Thirty-three other properties, including 5 districts and 28 individual buildings have been evaluated as eligible for the National Register or Tempe Register but not formally listed. The other 15 properties are post-World War II subdivisions that the Tempe Historic Preservation Office identified as warranting further consideration for inclusion in the Tempe Register.

Record Review Results: Potential Unrecorded Historic Resources

Historical maps and aerial photographs were reviewed to assess the potential for unrecorded historical resources within the records review area. The review determined that the General Land Office conducted the first cadastral survey of the area in 1868. The General Land Office surveyors mapped no cultural features in the power plant parcel, and only a few were mapped in the vicinity, including a short irrigation ditch, a road, and a settler's cabin along the road west of the parcel on the north side of the Salt River. The road from Maricopa Wells to Fort McDowell was mapped about 3.5 miles southeast of the power plant parcel, and two other short segments of unnamed roads and an "old esca" (a term General Land Office surveyors apparently used to label features now interpreted as abandoned prehistoric Hohokam canals) were mapped farther to the northeast, east, and south. Cadastral surveys in 1888 and in 1910 covered part of the Salt River Indian Reservation on the north side of the Salt River, and mapped irrigation ditches, extensive fields, roads, fences, clusters of "huts" that must have been native homes, an old trading store, and a cemetery.

The U.S. Reclamation Service surveyed the Salt River Valley in 1902 and 1903 and the resulting topographic and irrigation map showed an irrigation lateral along the west side of the power plant parcel and another lateral oriented east-west through the parcel. Two other short laterals at the north edge of the parcel along the south edge of the Salt River channel angled across the northeastern part of the parcel.

Those laterals, which branched from the Hayden Canal, indicate the area was being farmed. The Reclamation map showed the Maricopa, Phoenix & Salt River Valley Railroad (which later became the Creamery Branch) just south of the eastern part of the southern boundary of the power plant parcel. A 1915 map labeled that railroad as the Arizona Eastern Railroad and showed a wagon road along the western and northern edges of the power plant parcel. A house was mapped just southwest of the parcel, south of what is today University Drive near the intersection with Dorsey Lane. As shown on the earlier Reclamation Service map, the 1915 map indicated the northeastern part of the parcel was within the sandy or gravelly margin of the Salt River channel.

The depictions of the power plant parcel were unchanged on 1938 and 1955 versions of topographic maps, but a 1957 map indicated the road near the western edge of the parcel terminated about 0.1 mile north of the southern boundary of the parcel at what appeared to be a farmstead with a house and two outbuildings, and two other houses were mapped on either side of the road south of the farmstead. The farmyard and houses were in an area that is now the Tempe/APS Joint Fire Training Center.

A 1934 aerial photograph indicates that almost the entire Power Plant parcel was being farmed except for a strip in the southwest corner where the buildings shown on the 1957 map were located. Even though those farmyards were not mapped on the 1938 and 1955 quadrangles, the photograph suggests they were already built by 1934, but the image is ambiguous. A 1954 aerial photograph indicates the power plant parcel continued to be farmed except for the strip in the southwest corner where houses and outbuildings stood. A more detailed 1957 aerial photograph indicated the parcel continued to be farmed and there were at least two farmyards in the southwest corner, and perhaps another farmhouse hidden by trees. A 1970 aerial photograph indicates the power plant and substations had been constructed, but the three large fuel oil storage tanks had not yet been built and the northwestern part of the power plant parcel was still being farmed. The farmhouses and buildings in the southwest corner of the parcel had been removed.

In summary, the review of historic maps and aerial photographs indicates that the power plant parcel was intensively farmed for decades before the power plant was developed. As many as three farmyards might have been built in the southwestern corner of the parcel, but apparently were demolished when the power plant was developed, and the subsequent development of the Tempe/APS Joint Fire Training Center probably obliterated any archaeological evidence of those farmyards. Archaeological remnants of historic irrigation laterals dating to the late nineteenth or early twentieth centuries might be present in the western, central, and northern parts of the parcel, but construction of the power plant and related facilities may have disturbed any archaeological evidence of those canals. The review indicated little potential for intact archaeological features dating to the historic era within the power plant parcel.

Evaluation of the Eligibility of the Ocotillo Power Plant for the Arizona Register

Because the Power Plant was completed in 1960 it is older than the 50-year age criterion for Arizona Register consideration. Facilities of the original Power Plant include steam generating units 1 and 2, a station building with steam turbines and generators, an administrative building/maintenance shop designed by local architect H.H. Green with elements of the International style, a large prefabricated steel and wood equipment building, two (2) smaller sheds of similar construction, two (2) cooling towers, a steel water storage tank, a steel diesel fuel storage tank, a 230-kilovolt (kV) substation, and a 69kV substation. An evaluation of those facilities concluded they did not have sufficient historical significance to warrant preservation and were not eligible for the Arizona Register.

Archaeological Monitoring

Although, very little of the power plant parcel had been surveyed for cultural resources, additional survey seemed unlikely to produce useful results because the parcel had been so intensively developed and almost no natural ground surface was exposed within the parcel. APS arranged for archaeological monitoring of geotechnical investigations to check for evidence of unrecorded buried archaeological resources. Because the investigations were limited to 21 borings, each only 8 inches in diameter, the potential of the monitoring to detect archaeological resources was extremely limited and no evidence of buried archaeological deposits was identified in the sediments removed by the borings. Evidence of disturbance and placement of fill was detected in the upper levels of some of the borings, and as expected in floodplain settings, the other deposits were variable, but almost all were classified as sandy. The sandy deposits often were well sorted with little fine sediment, reflecting a relatively high energy depositional environment not conducive to preserving archaeological deposits. Some borings, however, revealed layers of sand mixed with silt, and less commonly with clay, and those sediments might represent lower energy over bank flood deposits that have potential to preserve archaeological deposits.

The area around each boring was inspected for artifacts. Only two Hohokam potsherds were found at one of the borings and it was later determined they had been brought in with imported fill dirt. More general inspection of the area, however, found many Hohokam artifacts on the earthen berms of the retention basin around the three large fuel oil storage tanks on the western side of the power plant parcel. The number and location of the artifacts suggested that construction of the fuel oil storage tanks might have disturbed archaeological deposits and features in fields associated with the nearby large Hohokam village site of La Plaza. Remnants of canals, seasonal field houses, and various types of pits have been found in Hohokam fields. Human burials are usually associated with village sites, but excavation at field house site AZ U:9:281(ASM), south of La Plaza, discovered three burials indicating that human remains also are sometimes associated with field houses.

Archaeological Testing

Because of the discovery of numerous Hohokam artifacts on the earthen berms of the retention basin in the area where the new gas turbines would be built, APS arranged for archaeological testing to determine if other archaeological deposits and features are buried in areas that could be disturbed by construction of new facilities. In conjunction with the testing, an estimated 85 to 90 percent of the surface artifacts concentrated on the berms of the retention basin were inventoried, and totaled 2,082 artifacts, most of which were Hohokam potsherds and pieces of flaked stone. Temporally diagnostic potsherds indicate the Hohokam probably farmed irrigated fields on the Lehi terrace within the power plant parcel sometime between the Gila Butte phase of the early Colonial period and the late Classic period Civano phase (circa A.D. 750 to 1450).

Thirteen test trenches, accumulating to 1,390 feet, were excavated mostly to depths of 4 to 5 feet with a backhoe equipped with a bucket 3 feet wide. The extent of testing was constrained by infrastructure in the power plant parcel, but the trenching constitutes about a 1 percent sample of the area that could be disturbed by construction of new facilities in areas that have not already been highly disturbed by construction of the three large fuel oil storage tanks and surrounding retention basin.

Testing to the east of the retention basin failed to find any archaeological features and the few artifacts that were found appeared to be in eroded contexts, suggesting that excavation of the retention basin may have disturbed most of the archaeological deposits and any archaeological features that were present. The only buried archaeological feature discovered by the test trenching is a Hohokam irrigation lateral canal oriented west/northwest. The canal was found about 3 to 5 feet below the surface in the very northwest corner of the power plant parcel. A layer of dark brown to brown clay to sandy clay loam to the north and south sides of the canal probably represents sediment accumulated in the fields that were watered by the ditch. Scattered charcoal may represent burning of field stubble. Three flakes and three potsherds were found in the trench walls in association with the ditch, and a Salado Polychrome potsherd recovered from the dirt excavated from the trench indicates the canal probably dates to the Civano phase of the late

Classic period and suggests pre-Classic period Hohokam or perhaps even pre-Hohokam archaeological deposits might be buried more deeply.

In general, the archaeological testing indicated that more than 2 feet of sediment were deposited across the project area by flood flows after the Hohokam occupation ended about 500 years ago, which essentially masks any surface indications of where archaeological deposits might be buried. One segment of a test trench, about 50 feet long, was dug to a depth of about 7 feet. That deeper trench proved to be within an erosion channel of undetermined lateral extent, but an eroded paleosol of undetermined age was found at the bottom of the channel, suggesting additional archaeological deposits might be buried deeper than the 4- to 5-foot depths tested by the backhoe trenches.

An archaeological site, designated AZ U:9:311(ASM), was defined to encompass the one buried canal feature that was found, the extensive scatter of disturbed artifacts on the berms of the retention basin, and a surrounding area where other buried features might be located. Because there are so few surface clues about the extent of the site, the site boundaries are somewhat arbitrary and further archaeological testing is necessary to better define the limits of the site. Further study of the highly disturbed scatter of artifacts on the berms of the retention basin is unlikely to yield important information, but investigation of the buried canal feature, which has not been disturbed by construction of the power plant and earlier agricultural tilling, might yield important information about the prehistoric Hohokam occupation of the Phoenix Basin, which would make the site eligible for the Arizona Register.

IMPACT ASSESSMENT

Evaluation of the historic-age buildings and structures of the Ocotillo Power Plant that would be affected by the proposed modernization of the plant concluded that none have historic significance that would make them eligible for the Arizona Register. A records review identified 110 historic districts, buildings, and structures listed in or eligible for the Arizona Register/National Register/Tempe Register. The closest of those is about 0.1 mile south of the power plant, 10 others are within 0.5 mile, 12 between 0.5 and 1.0 mile, and 87 between 1 and 2 miles of the power plant parcel. The height and massing of the five proposed new gas turbines would be approximately equivalent to five relatively small 3 story buildings with their stacks reaching heights of approximately 85 feet, which is substantially less than the two considerably more massive steam turbines at the power plant that are 178 feet tall. Because the project would involve removal of the two steam units, two large cooling towers, and three large abandoned fuel oil storage tanks, the modified power plant facilities are likely to be less visible than the current facilities are from historic properties in the surrounding area, and no adverse indirect visual impacts are anticipated.

Archaeological investigations resulted in the designation of site AZ U:9:311(ASM) to encompass the single buried lateral canal feature discovered by archaeological testing and more than 2,000 Hohokam artifacts found in highly disturbed contexts on the earthen berms of the retention basin around the three large fuel oil storage tanks in the project area. Further study of the artifacts on the retention basin berms is unlikely to yield important information because the artifacts are in such a disturbed context, but further investigation of the buried canal feature might have potential to yield important information about the prehistoric Hohokam occupation of the Phoenix Basin, which would make the site eligible for the Arizona Register. The canal feature is in the very northwest corner of the power plant parcel, and it might not be disturbed by the proposed power plant modernization. If development of final designs for the project concludes avoidance is not feasible, disturbance by construction activities would be an adverse impact on the archaeological site.

Additional Investigation and Potential Mitigation

Investigations have identified only limited intact archaeological resources in the project area, but APS plans to conduct deeper and more extensive preconstruction archaeological testing to determine whether other archaeological features might be buried in areas that could be disturbed by construction of the new facilities, and if so, whether they are in locations that can or cannot be avoided. If the single canal feature identified at site AZ U:9:311(ASM) cannot be avoided or if further testing identifies additional intact archaeological deposits and features that would be disturbed by construction activities, APS will develop and implement a plan to recover and preserve artifacts and information to mitigate the impacts of the proposed power plant modernization.

APS has consulted with the SHPO, the Tempe City Historic Preservation Office, and potentially interested tribes (see copies of correspondence included in Exhibit J). APS will continue to consult with those parties to plan and implement measures to mitigate any adverse effect on archaeological site AZ U:9:311(ASM).

APPENDIX I.

Environmental Justice.