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:	**July 14, 2014**
Updated:	**January 15, 2015**
Updated:	**September 25, 2015**

Prepared for:

Arizona Public Service
400 North 5th Street
Phoenix, Arizona 85004
www.aps.com

Prepared By:

RTP Environmental Associates Inc.
1591 Tamarack Ave
Boulder, CO 80304

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.

Table of Contents

Tables

Figures

Attachments

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.

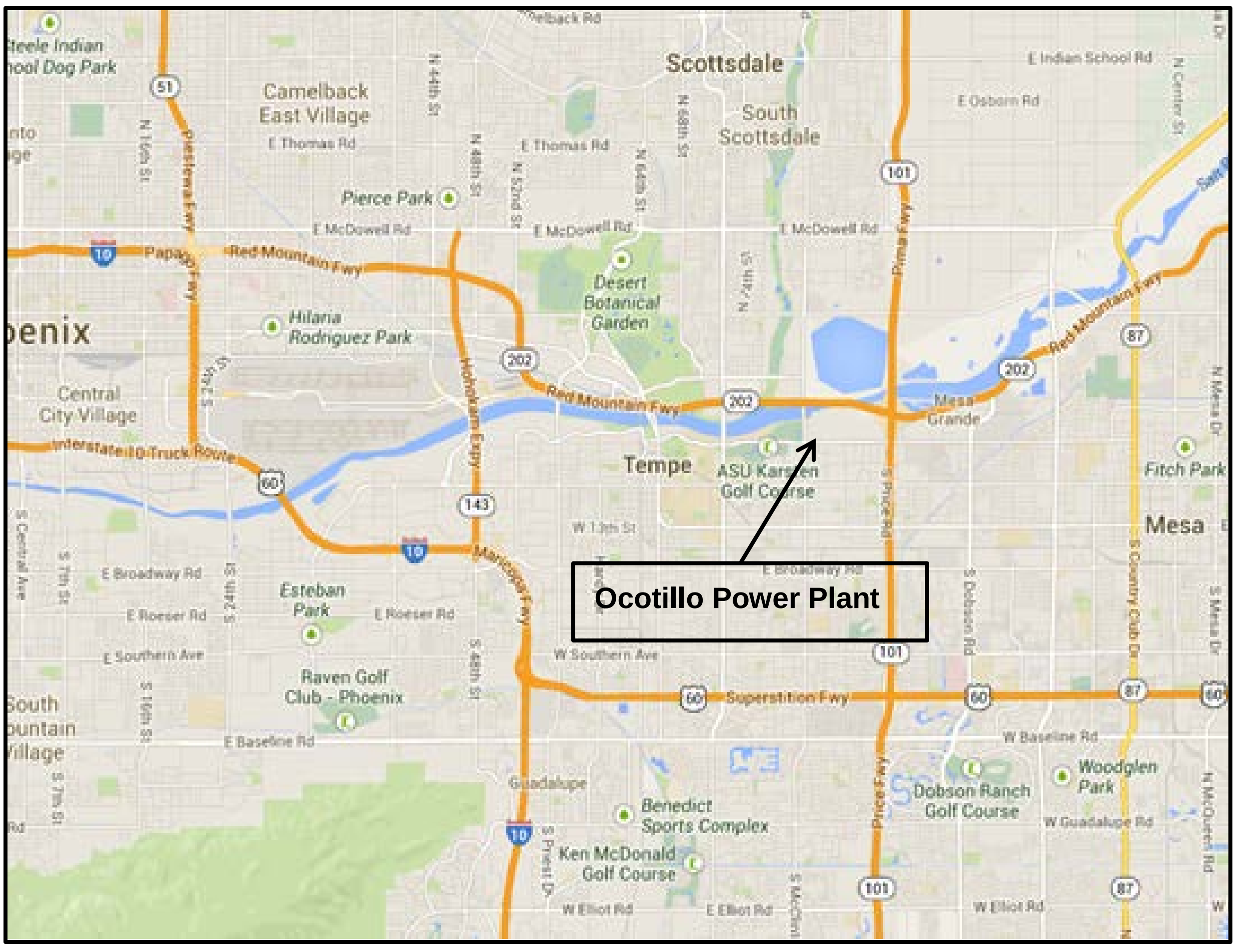

FIGURE 2-2. Aerial image of the existing Ocotillo Power Plant.

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).

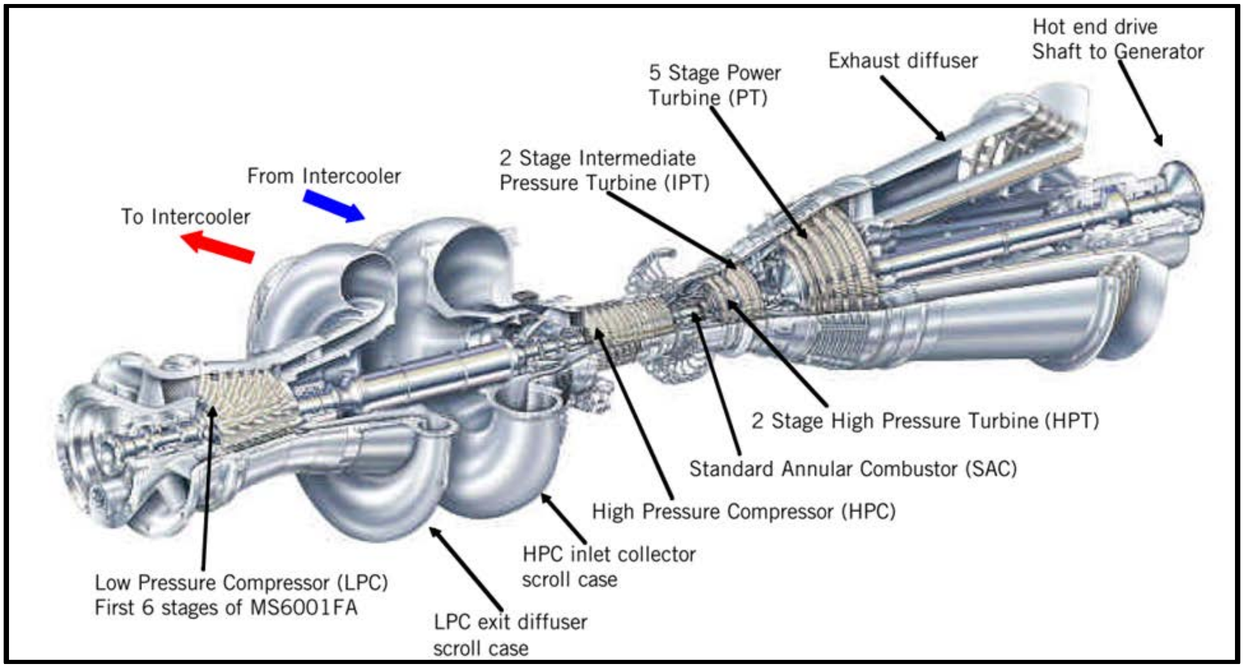

FIGURE 2-4. Typical installation of a General Electric Model LMS100 simple cycle gas turbine (from General Electric Company).

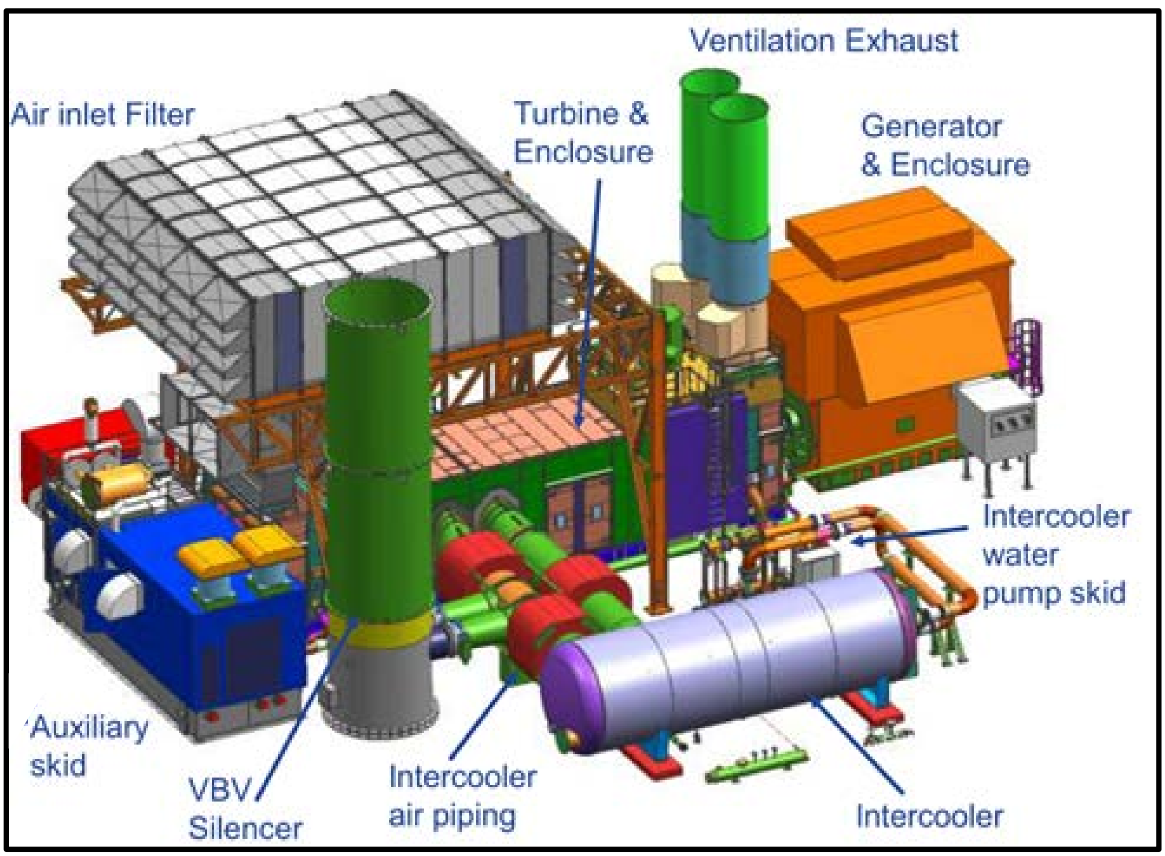

TABLE 2-1. General specifications for the proposed General Electric Model LMS100 simple cycle gas turbines.

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 100 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	15,290
Exhaust Gas Temperature, ^{o}F	752
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.
- 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		NORMAL OPERATION					
		Heat Input per GT	Maximum Emission Rate		Fuel Use Limit	Emissions per GT	Emissions for GT3-GT7
		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 1.49×10^6 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	Maximum Heat Input	Potential to Emit, each turbine	Potential to Emit, all 5 turbines
		lb/mmBtu	mmBtu/hr	tons/year	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:

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

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 non-emergency operation of each generator to no more than 100 hours per year, based on a 12-month rolling average. 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	2.6
Nitrogen Oxides	NO_x	6.4 (10.5)*	4.8 (7.83)*
Particulate Matter	PM	0.20 (0.54)	0.15 (0.40)
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. The engine family standards are in parantheses ( ).

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	1.08	2.16
Nitrogen Oxides	NO_x	6.90	3,750	56.99	2.85	5.70
Particulate Matter	PM	0.40	3,750	3.30	0.17	0.33
Particulate Matter	PM_{10}	0.40	3,750	3.30	0.17	0.33
Particulate Matter	$PM_{2.5}$	0.40	3,750	3.30	0.17	0.33
Sulfur Dioxide	SO_2	0.0044	3,750	0.037	0.00	0.0037
Vol. Org. Cmpds	VOC	0.20	3,750	1.65	0.083	0.17
Sulfuric Acid Mist	H_2SO_4	4.4E-04	3,750	0.0037	0.00	0.00037
Flourides	F	7.9E-04	3,750	0.0065	0.00	0.00065
Lead	Pb	2.7E-05	3,750	0.0002	0.00	0.00002
Carbon Dioxide	CO_2	476.7	3,750	3,937.7	196.89	393.77
Greenhouse Gases	CO_2e	478.4	3,750	3,951.2	197.56	395.12

Footnotes

1. Potential emissions are based on 100 hours per year of non-emergency operation.
2. The CO, 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. The NO_x emissions are based on the Maricopa Rule 324 emissions limit, which is lower than the Tier 2 family emission limit.
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	0.000944	0.00189
Toluene	108-88-3	2.81E-04	24.3	0.0068	0.000342	0.00068
Xylene	1330-20-7	1.93E-04	24.3	0.0047	0.000235	0.00047
Formaldehyde	50-00-0	7.89E-05	24.3	0.0019	0.000096	0.00019
Acetaldehyde	75-07-0	2.52E-05	24.3	0.0006	0.000031	0.00006
Acrolein	107-02-8	7.88E-06	24.3	0.0002	0.000010	0.00002
Naphthalene	91-20-3	1.30E-04	24.3	0.0032	0.000158	0.00032
Total PAH		2.12E-04	24.3	0.0052	0.000258	0.00052
Arsenic		1.10E-05	24.3	0.0003	0.000013	0.00003
Beryllium		3.10E-07	24.3	0.0000	0.000000	0.00000
Cadmium		4.80E-06	24.3	0.0001	0.000006	0.00001
Chromium		1.10E-05	24.3	0.0003	0.000013	0.00003
Manganese		1.40E-05	24.3	0.0003	0.000017	0.00003
Mercury		1.20E-06	24.3	0.0000	0.000001	0.00000
Nickel		4.60E-06	24.3	0.0001	0.000006	0.00001
Selenium		2.50E-05	24.3	0.0006	0.000030	0.00006
TOTAL					**0.0022**	**0.0043**

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 100 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 100 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 35,000 gallons per year. Potential VOC emissions based on the U.S. EPA's TANKS program, Version 4.0.9d is 2.74 pounds per year for each tank, or total VOC emissions of 0.003 tons per year 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 ^{o}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		2.2				241.3
Nitrogen Oxides	NO_x	134.6		6.5				125.3
Particulate Matter	PM	54.9	5.4	0.3				60.6
Particulate Matter	PM_{10}	54.9	1.7	0.3				56.9
Particulate Matter	$PM_{2.5}$	54.9	1.0	0.3				56.3
Sulfur Dioxide	SO_2	5.9		0.00				5.9
Vol Organic Cmpds	VOC	43.1		0.17	0.003			43.3
Sulfuric Acid Mist	H_2SO_4	0.6		0.00037				0.6
Fluorides (as HF)	HF	0.000		0.00065				0.00065
Lead	Pb	0.005		0.00002				0.0050
Carbon Dioxide	CO_2	1,099,504		393.8				1,099,898
Greenhouse Gases	CO_2e	1,100,640		395.1		132.3	102.4	1,101,269

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	Maximum Heat Input	Potential to Emit, each turbine	Potential to Emit, GT1 and GT2 combined
		lb/mmBtu	mmBtu/hr	tons/year	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.

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	241.3	100	YES
Nitrogen Oxides	NO_X	125.3	40	YES
Particulate Matter	PM	60.6	25	YES
Particulate Matter	$PM_{2.5}$	56.3	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	1,099,898	75,000	YES
Greenhouse Gases	CO_2e	1,101,269	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	241.3	14.6	226.7	100	**YES**
Nitrogen Oxides	NO_X	125.3	85.9	39.4	40	**NO**
Particulate Matter	PM	60.6	8.0	52.6	25	**YES**
Particulate Matter	$PM_{2.5}$	56.3	5.3	51.0	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	1,099,898	73,972	1,025,926	75,000	**YES**
Greenhouse Gases	CO_2e	1,101,269	74,045	1,027,224	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.

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 6.9 g NO_x/hp-hr.
Particulate Matter PM and $PM_{2.5}$	PSD BACT	Tier 2 Emission Standard of 0.4 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 100 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. 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).

<table>
<tr><th>Emissions Unit(s)</th><th>SO_2</th><th>NOx</th><th>CO</th><th>PM_{10}</th><th>$PM_{2.5}$</th><th>VOC</th><th>CO_2</th></tr>
<tr><td>GT3 - GT7</td><td>5.9</td><td rowspan="2">125.3</td><td>239.2</td><td rowspan="4">63.0</td><td>54.9</td><td>43.1</td><td>1,099,504</td></tr>
<tr><td>Emergency Generators</td><td>0.01</td><td>2.2</td><td>0.3</td><td>0.17</td><td>393.8</td></tr>
<tr><td>GTCT</td><td>NA</td><td>NA</td><td>NA</td><td>1.5</td><td>NA</td><td>NA</td></tr>
<tr><td>GT1-2</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td></tr>
</table>

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.

7.1 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.

7.2 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.

7.3 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.

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	2.2	8.9					373.1
Nitrogen Oxides	NO_x	479.7	125.3		0.3					605.3
Particulate Matter	PM	12.4	54.9	0.3	0.0	5.4				73.0
Particulate Matter	PM_{10}	12.4	54.9	0.3	0.0	1.7				63.0
Particulate Matter	$PM_{2.5}$	12.4	54.9	0.3	0.0	1.0				68.6
Sulfur Dioxide	SO_2	0.9	5.9	0.00	0.00					6.8
Vol. Organic Cmpds	VOC	3.1	43.1	0.17	0.01		0.84			47.3
Sulfuric Acid Mist	H_2SO_4	0.1	0.6	0.0	0.0					0.68
Fluorides (as HF)	HF	0.0	0.0	0.0	0.0					0.0007
Lead	Pb	0.0007	0.0049	0.0	0.0					0.006
Carbon Dioxide	CO_2	175,371	1,099,504	393.8	51.7					1,275,320
Greenhouse Gases	CO_2e	175,552	1,100,640	395.1	51.9			132	102	1,276,873

Chapter 8. Endangered Species and Historic Preservation Analyses.

8.1 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.

8.2 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 9. 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.

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 ______

Official Title of Signer: **Plant Manager**

12. Typed or Printed Name of Signer: **Dennis Irvin**

Date: ______ Phone Number: ______

Appendix B.

Control Technology Review

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.

Appendix E.

Detailed Baseline Emission Data for the Ocotillo Steam Generating Units

APPENDIX F.

Air Quality Analysis Protocol and Report.

APPENDIX G.

Special Status Species and Species of Concern.

APPENDIX H.

Historic Preservation.

APPENDIX I.

Environmental Justice.