Exhibit 6

Technical Support Document (“TSD”) (December 2015)

Technical Support Document
APS Ocotillo Power Plant
Permit Number V95-007
Permit Revision 2.1.0.0
Issuance Date: xxxxxxxxxx

TABLE OF CONTENTS

LIST OF TABLES

1. **APPLICANT:**
Arizona Public Service (APS)
P.O. Box 53933
Phoenix, AZ 85043

Initial Application date: 04/09/2014
Supplemental Data Submittal Date: 10/06/2015

2. **PROJECT LOCATION:**
The Arizona Public Service Ocotillo Power Plant is located at 1500 East University Drive, Tempe, AZ 85281.

Latitude:	33°25’30”
Longitude:	111°54’31”
Average Elevation:	1,175 feet above mean sea level

3. **PROJECT DESCRIPTION:**
The Ocotillo Power Plant is located at 1500 East University Drive, Tempe Arizona, 85281, in Maricopa County. The APS Ocotillo Power Plant and the proposed Project are classified under SIC code 4911. The Plant has been in operation since 1960. The facility 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 and were 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 County Rules 210 and 240, and operates under Title V Operating Permit V95-007.

The is planning to install five new natural gas-fired GE Model LMS100 simple cycle GTs (GT3 through GT7) and associated equipment, including a hybrid Partial Dry Cooling System and two 2.5 MW emergency generators, at the Ocotillo Power Plant. As part of the Project, the Applicant 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. The existing GT1 and GT2 will no longer have dual-fuel capability and will only burn Pipeline Natural Gas. This Technical Support Document (TSD) is for a significant permit revision to allow for construction and operation of the proposed Project.

The Project will utilize state-of-the-art gas turbine technology to generate electricity. The Applicant 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 the Applicant 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.

The Maricopa County Air Quality Department's assessment of the APS Ocotillo project is as follows:

- The Ocotillo plant will utilize highly efficient simple-cycle gas turbines.
- The PSD permitting requirements apply to the Project only for carbon monoxide (CO), particulate matter less than 100 microns (PM), particulate matter less than or equal to 2.5 microns ($PM_{2.5}$), and greenhouse gas (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 the first new GT commences operation, the Ocotillo Plant will no longer be a major source of particulate matter less than or equal to 10 microns (PM_{10}).
- The nonattainment NSR permitting requirements do not apply to the Project.
- The air quality impacts of the Project are insignificant when compared to EPA impact thresholds.

4. PROJECT JUSTIFICATION:

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.

The Applicant 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% the Applicant'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, the Applicant has approximately 1,200 MW of renewable generation and an additional 46 MW in development. Within Maricopa County and the Phoenix metropolitan area, the Applicant 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 the Applicant's 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.

5. PROJECT EMISSION UNITS:

The Project design is based on five General Electric (GE) LMS100 gas-fired simple cycle combustion turbine generators (GTs), which can comply with the proposed BACT air emission limits when operating at loads ranging from 25% to 100% of the maximum output capability. 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. Cooling for the High Temperature Intercooler (HTIC) at each LMS100 turbine will be provided by a hybrid Partial Dry Cooling System (PDCS) closed cycle cooling tower.

The Project will include the proposed installation of two emergency generators (EG1 and EG2) (or their equivalent) powered by diesel (compression ignition) engines. These generators will have a nominal standby electric generating capacity of 2.5 MW (each). Because these new generators will be used solely as emergency diesel generators, the Applicant is proposing operational limits for each generator of no more than 500 hours in any 12 consecutive month period. This operational limit is explained in more detail in Chapter 7 of this TSD. Table 1 is a summary of the technical specifications for each emergency generator.

TABLE 1: Technical Specifications for the Proposed New Emergency Generators

Generator Standby Rating, MW	2,500
Engine Power at Standby Output, brake-horsepower	3,386
Maximum Diesel Fuel Consumption Rate, gal/hr	175
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.

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, sulfur hexafluoride (SF_6) insulated electrical equipment, and natural gas piping systems and components. The emission units for the Ocotillo Modernization Project are as follows:

TABLE 2: 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	SF_6	SF_6 Insulated Electrical Equipment
10	DFT1 and DTF2	Two 10,000 gallon diesel fuel storage tanks
11	NGPS	Natural Gas Piping Systems

6. **EMISSION CONTROLS:**

For the proposed new gas turbines, the combustion gases exit the turbine at approximately 760 ºF. The exhaust gases will then pass through two post combustion air quality control systems, including oxidation catalysts for the control of CO and volatile organic compounds (VOC), and selective catalytic reduction (SCR) systems for the control of nitrogen oxides (NO_x) emissions.

For the proposed new gas turbines, CO and VOC emissions will 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.

7. **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 reduces 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.

8. **PERMIT HISTORY:**

The history of the APS Ocotillo Power Plant are as follows:

TABLE 3: Permit History

Date Received	Revision Number	Description
07/27/2000	0.0.0.0	Submitted application for new permit for power plant in Tempe.
12/16/2010	1.0.0.0	Permit renewal.
08/16/2002	1.0.1.0	Minor modification to add emergency generator.
04/14/2014	1.1.0.0	Significant revision to add 5 simple cycle turbines and remove 2 existing steam generating units. GT1 and GT2 will no longer have dual-fuel capability. Two 2.5 megawatt emergency generators will also be added.
04/09/2014	0.1.0.0	Significant revision.
10/08/2015	2.0.0.0	Permit renewal.

9. DESCRIPTION OF REGULATED ACTIVITIES:

Tables 4 and 5 display the regulated activities before and after the modernization project.

TABLE 4: Regulated Activities before Revision

Equipment/Process	Regulated Activity	Regulated Pollutants
Steam Boiler 1 and 2	Fuel Combustion	SO_2
Combustion Turbines 1 and 2	Fuel Combustion	SO_2
Cooling Tower	Drift Loss	
Gasoline Tank	Evaporation Loss	VOC, HAPs
Abrasive Blasting Building	Abrasive Blasting	PM_{10}, $PM_{2.5}$
Asbestos Removal Activities	Asbestos Removal	Asbestos
Generac Emergency Generator	Fuel Combustion	SO_2, NO_x, VOC, CO, PM_{10}, $PM_{2.5}$, HAPs

TABLE 5: Regulated Activities after Revision

Equipment/Process	Regulated Activity	Regulated Pollutants
5 Combustion Turbines (GT3-GT7)	Fuel Combustion	SO_2, NO_x, VOC, CO, PM_{10}, $PM_{2.5}$, HAPs
Combustion Turbines 1 and 2	Fuel Combustion	SO_2
Cooling Tower	Drift Loss	PM_{10}, $PM_{2.5}$
Gasoline Tank	Evaporation Loss	VOC, HAPs
Abrasive Blasting Building	Abrasive Blasting	PM_{10}, $PM_{2.5}$
Asbestos Removal Activities	Asbestos Removal	Asbestos
Generac Emergency Generator	Fuel Combustion	SO_2, NO_x, VOC, CO, PM_{10}, $PM_{2.5}$, HAPs
2.5 Megawatt Emergency Generators	Fuel Combustion	SO_2, NO_x, VOC, CO, PM_{10}, $PM_{2.5}$, HAPs

10. COMBUSTION TURBINE NORMAL OPERATION EMISSIONS:

The manufacturer's emission data are presented in the revised Applicant's application, dated September 30, 2015, in Appendix C and in this TSD in Appendix A. The emission data represent 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 (HHV)), and the proposed BACT emission limits and manufacturer's maximum hourly emission rates. The Applicant has proposed 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} Non-attainment NSR rules, so that the Project does not trigger Non-attainment NSR 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, VOCs, 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 tolling 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) (equivalent to 1,600 operating hours per year per turbine) combined across the existing gas turbines GT1 - GT2 to limit the potential emissions for VOCs.
- Combustion of only EPA definition "Pipeline Natural Gas" in all of the existing and new gas turbines GT1 through GT7. The EPA 40 CFR 72.2 definition of "Pipeline Natural Gas" is:

  > "Pipeline Natural Gas" means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline Natural Gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, Pipeline Natural Gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.

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.

The potential emissions for normal operations for GT3 – GT7, based on the annual fuel use limit, are summarized in Table 9.

11. 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 the purposes of maintenance checks and readiness testing) 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 6. 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.

TABLE 6: 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*	4.8*
Particulate Matter	PM	0.20	0.15
Non-Methane Hydrocarbons	NMHC	n/a	n/a

Footnote:
* 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 Applicant is proposing to install diesel generators which comply with the Tier 2 emission standards under 40 CFR §89.112. In addition, the Applicant is proposing to limit the operation of each generator to no more than 500 hours per year, based on a 12-month rolling average, consistent with the Maricopa County definition of "emergency engine". The potential emissions for each 2.5 MW diesel-fired emergency electric generator, based on these proposed limits, are summarized in Table 7.

TABLE 7: Potential Emissions for Each 2.5 MW Generator and for Both Generators Combined

POLLUTANT		Emission Factor	Power Rating	Potential to Emit, Each Generator		Potential to Emit, Both Generators
		g/hp-hr	hp	lb/hr	ton/year	ton/year
Carbon Monoxide	CO	2.61	3,750	21.56	5.39	10.8
Nitrogen Oxides	NO_x	4.77	3,750	39.42	9.86	19.71
Particulate Matter	PM	0.15	3,750	1.24	0.31	0.62
Particulate Matter	PM_{10}	0.15	3,750	1.24	0.31	0.62
Particulate Matter	$PM_{2.5}$	0.15	3,750	1.24	0.31	0.62
Sulfur Dioxide	SO_2	0.0044	3,750	0.037	0.01	0.0184
Vol. Org. Cmpds	VOC	0.20	3,750	1.65	0.413	0.83
Sulfuric Acid Mist	H_2SO_4	4.4E-04	3,750	0.0037	0.00	0.00184
Fluorides	F	7.9E-04	3,750	0.0065	0.00	0.00326
Lead	Pb	2.7-05	3,750	0.0002	0.00	0.00011
Carbon Dioxide	CO_2	476.7	3,750	3,937.7	984.43	1,968.86
Greenhouse Gases	CO_2e	478.4	3,750	3,951.2	984.43	1,975.61

Footnotes:

1. Potential emissions are based on 500 hours per year of 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.
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 8. The potential HAP emissions in Table 8 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 8: Potential Hazardous Air Pollutant (HAP) Emissions for the Emergency Generators

AIR POLLUTANT	CAS #	Emission Factor[1]	Heat Input	Potential to Emit, Each Generator		Potential to Emit, Both Generators
		lb/MMBtu	MMBtu/hr	lb/hr	ton/year	ton/year
Benzene	71-43-2	7.76E-04	24.3	0.0189	0.004719	0.00944
Toluene	108-88-3	2.81E-04	24.3	0.0068	0.001709	0.00342
Xylene	1330-20-7	1.93E-04	24.3	0.0047	0.001174	0.00235
Formaldehyde	50-00-0	7.89E-05	24.3	0.0019	0.000480	0.00096
Acetaldehyde	75-07-0	2.52E-05	24.3	0.0006	0.000153	0.00031
Acrolein	107-02-8	7.88E-06	24.3	0.0002	0.000048	0.00010
Naphthalene	91-20-3	1.30E-04	24.3	0.0032	0.000158	0.00032
Total PAH		2.12E-04	24.3	0.0052	0.001289	0.00258
Arsenic		1.10E-05	24.3	0.0003	0.000067	0.00013
Beryllium		3.10E-07	24.3	0.0000	0.000002	0.00000
Cadmium		4.80E-06	24.3	0.0001	0.000067	0.00013
Chromium		1.10E-05	24.3	0.0003	0.000013	0.00003
Manganese		1.40E-05	24.3	0.0003	0.000085	0.00017
Mercury		1.20E-06	24.3	0.0000	0.000007	0.00001
Nickel		4.60E-06	24.3	0.0001	0.000028	0.00006
Selenium		2.50E-05	24.3	0.0006	0.000152	0.00030
TOTAL					**0.0108**	**0.0216**

Footnotes:

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

12. DIESEL FUEL OIL STORAGE TANKS:

The Project will include two 10,000 gallon diesel fuel oil storage tanks. Based on the operational limits for the diesel generators of 500 hours per year and a maximum fuel consumption rate of 175 gallons per hour, the maximum annual throughput for each tank would be 87,000 gallons per year. Potential VOC emissions based on the U.S. EPA's TANKS program, Version 4.0.9d (which is based on the equations from AP-42, Section 7.1, Organic Storage Tanks), is 4.45 pounds per year for each tank, or total VOC emissions of 0.005 (rounded up to 0.01) tons per year for both tanks combined.

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

For simple cycle 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 10. For these LMS100 GTs, the 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 length of time for a normal shutdown, that is, the time from the cessation of water injection to the time when the flame is out, is normally 11 minutes. Therefore, the normal duration for a normal startup and shutdown cycle or “event” is 41 minutes. In Table 10, 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 total of 2,490 hours per year for GT3-GT7 combined.

14. POTENTIAL EMISSIONS FOR GTs:

The total potential emissions for the GTs are the sum of emissions during estimated normal operations and the estimated numbers of startup/shutdown, and are presented in Table 11. The total potential emissions for the Ocotillo Modernization Project are found in Table 17.

TABLE 9: Potential Emissions for the 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 1 hour average**	**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 106 MMBtu/yr.
2. The SO_2 emission factor of 0.0006 lb/MMBtu is based on "Pipeline Natural Gas". Sulfuric acid mist is estimated as 10% of the SO_2 emissions. The sulfuric acid mist emission rate equal to 10% of the SO_2 is a conservative (high) estimate. Most external combustion sources such as boilers with low excess oxygen levels have typical SO_2 to SO_3 (and then to sulfuric acid mist) conversion rates of about 1%.
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[3]**	**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**

Note: There are three main categories of fluorinated greenhouse gases--hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). The major emissions source of HFCs is their use as refrigerants, in air conditioning systems in both vehicles and buildings. PFCs are compounds produced as a by-product of various industrial processes associated with aluminum production and the manufacturing of semiconductors. Sulfur hexafluoride is used in electrical transmission equipment. Fluorinated greenhouse gas emissions are not associated with natural-gas combustion activities.

In 40 CFR Part 98.42, EPA lists the GHGs that electrical generation units emit in quantities of importance, and therefore must be reported. These include CO_2, N_2O, and CH_4 gases, but do not include any fluorinated greenhouse gases. Therefore, the APS Ocotillo air permit application did not consider the insignificant emissions of fluorinated greenhouse gases.

TABLE 10: Potential Emissions for the 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 Compounds	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

Footnote:
The fuel use during startup and shutdown is estimated based on 366 MMBtu per startup sequence and 43 MMBtu per shutdown sequence for a total of 409 MMBtu per 41 minute event. This equates to 1.49 x 106 MMBtu per year for all startup/shutdown events for all 5 turbines combined

TABLE 11. 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

15. **HAZARDOUS AIR POLLUTANTS:**

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 12. 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 12, the proposed new GTs will not have emissions in excess of these major source levels. The Ocotillo Power Plant is currently a minor (area) source of HAPs, and the proposed modification will not change the minor HAP source status of this facility.

TABLE 12: Potential Hazardous Air Pollutant (HAP) Emissions for GT3-GT7

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

Footnotes:

1. The emission factors are from the U.S. EPA's WebFIRE database. These factors are from the U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42, Volume 1: Stationary Point and Area Sources, Section 3.1,

Stationary Gas Turbines for Electricity Generation.

2. The emission factor for formaldehyde (CH2O) emissions is 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)

16. 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 13.

TABLE 13: 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

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, air flow is induced in a countercurrent pattern 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.

Maricopa County uses an emission factor of 31.5% to convert total cooling tower PM emissions to PM_{10} emissions consistent with the majority of power plants in Maricopa County. 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. Based on this information, Maricopa County used the same conversion factor.

Table 14 presents the calculated PM, PM_{10}, and $PM_{2.5}$ emissions for the cooling tower, based on the particle size multipliers of 0.315 for PM_{10} emissions and 0.189 (0.315 x 0.6) for $PM_{2.5}$ emissions which have been previously approved in PSD permitting actions.

TABLE 14: 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

17. 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 designed to be gas-tight and 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 15: Potential Fugitive SF_6 Emissions from the Planned SF_6 Insulated Electrical Equivalent and the Equivalent GHG Emissions

Breaker Type	Breaker Count	Total SF_6 per Component (lb)	Leak Rate (% per year)	SF_6 Emissions (tpy)	CO_2e Factor	Potential Emissions[1] (tons CO_2e/yr)
230 kV	9	135	0.50	0.0030	32,900	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

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

18. 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 16 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 16: Potential Fugitive Methane Emissions from the Natural Gas Piping Systems and the Equivalent GHG Emissions

Component Type	Component Count	Emission Factor[1] scf/hour/component	Specific Volume scf/lb CH4	Methane (CH_4) (tpy)	CO_2e Factor	Potential Emissions tons 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**

1. The emission factors are from 40 CFR Part 98, Table W-1A for onshore natural gas production, Western U.S.
2. The CO_2e factor is from 40 CFR 98, Subpart A, Table A-1.

3. The specific volume of methane at 68 of is based on a specific volume of 385.5 standard cubic feet per lb-mole of gas, and a methane molecular weight of 16.0 lb/lb-mole.
4. Methane emissions are based on the worst-case assumption that the natural gas is 100% methane by volume.

19. TOTAL PROJECT EMISSIONS:

Table 17 summarizes the total project emissions for the Ocotillo Power Plant Modernization Project. For NO_x emissions, compliance with the allowable emission cap will be demonstrated using NO_x 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 17: Summary of Potential Emissions for the Ocotillo Modernization Project

POLLUTANT		Emissions, tons per year						
		GT3-GT7	GTCT	Emergency Generators	Diesel Fuel Storage Tanks	SF_6 Insulated Equipment	Natural Gas Piping	TOTAL
Carbon Monoxide	CO	239.2		10.8				249.9
Nitrogen Oxides	NO_x	134.6		19.7				125.3[1]
Particulate Matter	PM	54.9	5.4	0.6				60.9
Particulate Matter	PM_{10}	54.9	1.7	0.6				57.2
Particulate Matter	$PM_{2.5}$	54.9	1.0	0.6				56.5
Sulfur Dioxide	SO_2	5.9		0.0184				5.9
Vol. Organic Cmpds	VOC	43.1		0.83	0.003			43.9
Sulfuric Acid Mist	H_2SO_4	0.6		0.00184				0.6
Fluorides (as HF)	HF	0.000		0.00326				0.00326
Lead	Pb	0.005		0.00011				0.00504
Carbon Dioxide	CO_2	1,099,504		1,968.9				1,101,473
Greenhouse Gases	CO_2e	1,100,640		1,975.6		132.3	102.4	1,102,850

1. A NO_x emission cap of 125.3 tpy is proposed across both the new GT3-GT7 units in combination with the two new emergency generators.

20. 40 CFR PART 60 SUBPART KKKK REQUIREMENTS:

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).

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:

a. Limit SO_2 emissions to 0.90 pounds per megawatt-hour gross output, or

b. Not burn any fuel which contains emissions in excess of 0.060 lb SO_2/MMBtu heat input.

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 in 40 CFR 60 Subpart KKKK. 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

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.

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. The Applicant 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. The Applicant will request 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.

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, the Applicant 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 Natural Gas” with a typical SO_2 emission rate of 0.0006 lb/MMBtu, this is the method that the Applicant proposes to meet the Subpart KKKK SO_2 monitoring requirements. “Pipeline Natural Gas” has a maximum of 0.5 grains of sulfur per 100 standard cubic feet. Therefore, the Applicant is only allowed to combust “Pipeline Natural Gas”, to comply.

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).

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 within 45 days after the completion of the performance test.

21. STANDARDS OF PERFORMANCE FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS, 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 /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).

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:

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

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

The Applicant proposed 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. 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.

22. 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 by the Applicant, and is included with their revised application as Appendix D.

23. 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 HAP emissions for the proposed new GE Model LMS100 gas turbines are detailed in Table 12. 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 12, 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 12 are based on the *uncontrolled* emission factor from the U.S. EPA's WebFIRE database.

Table 18 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 proposed operational limits. Table 19 is a summary of the total potential HAP emissions for the Ocotillo Power Plant after the Modernization Project, based on the proposed operational limits for the new and existing gas turbines. From Table 19, 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 18: Hazardous Air Pollutant (HAP) Emissions for GT1-GT2 Based on the Operational Limits in this TSD

POLLUTANT	CAS No.	Emission Factor lb/MMBtu	Maximum Heat Input MMBtu/hr	Potential to Emit, each turbine (tpy)	Potential to Emit, GT1 and GT2 combined (tpy)
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
Acetaldehyde	75-07-0	4.0E-05	915	0.029	0.06
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 (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 both turbines combined of 2,928,000 MMBtu (HHV) per year

TABLE 19: 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	0.142
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	7.715
Xylene	1330-20-7	0.094	0.602	0.00047	0.698
Naphthalene	91-20-3	0.002	0.012	0.00032	0.016
PAH		0.003	0.021	0.00052	0.027
Propylene oxide	75-56-9	0.042	0.273		0.315
Toluene	108-88-3	0.190	1.222	0.00068	1.417
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**

24. 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.

The MCAQD administers the PSD program pursuant to the requirements under 40 CFR §52.21 which has been delegated to the MCAQD since 1993. 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. 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 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 2008 8-hour ozone standards (classification of moderate). The area is designated as a maintenance area for CO. The area is designated attainment/unclassifiable for all other criteria pollutants.

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:

- Installation of the Best Available Control Technology (BACT) for each regulated pollutant which exceeds the significant levels.

- An air quality analysis to demonstrate that new emissions will not cause or contribute to a violation of any applicable NAAQS or PSD increment.
- Class I area impacts analysis.
- An additional impacts analysis.
- Public involvement and participation.

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:

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

25. MAJOR 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 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 NO_x and GHG emissions, both before and after the Project, will be greater than the major source threshold, and therefore the facility will continue to be classified as a major source with respect to the PSD rules.

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:

210.1 Any stationary source located in a nonattainment area that emits, or has the potential to emit, 100 tons per year or more of any conventional air pollutant, except as follows:

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

210.8 A major source that is major for oxides of nitrogen shall be considered major for ozone in nonattainment areas classified as marginal, moderate, serious or severe.

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 ozone nonattainment area pollutants (NO_x and VOC emissions) is 100 tons per year.

Because the current potential PM_{10} and NO_x emissions from the Ocotillo Power Plant are greater than the nonattainment major stationary source thresholds, the Ocotillo Power Plant is an existing major stationary source for PM_{10} and ozone under the NANSR program. However the Applicant has proposed a plant-wide emission cap of 63 tpy 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, the Project will not be subject to the NANSR or PSD programs for PM_{10} emissions. In addition, the Ocotillo Power Plant potential VOC emissions both before and after the Project are less than 100 tpy, therefore the Project will not be subject to the NANSR or PSD programs for VOC emissions.

a. 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):

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.

i. 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 20: NANSR and PSD Significant Emission Rates for the Ocotillo Power Plant

Pollutant	PSD Significant Threshold (tpy)
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).

ii. Step 2: Net Emission 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.

The Applicant has proposed to permanently retire the existing Ocotillo Steam Turbine 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 Steam Turbines Units 1 and 2 which have been netted against the increase in emissions from the proposed new emissions units.

b. Step 1: Project Emission Increases:
The Ocotillo Power Plant Modernization Project will involve the construction of five new gas turbines, a cooling tower, two emergency generators, and other associated equipment. 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):

i. 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 21. If the project emission increase is less than the PSD 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 review for that pollutant. From Table 21, 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 major modification for these pollutants.

TABLE 21: Project Emissions Compared to the Significant Levels for the Ocotillo Modernization Project

POLLUTANT		New Project Emissions (tpy)	PSD/NANSR Significant Level (tpy)	Over?
Carbon Monoxide	CO	249.9	100	YES
Nitrogen Oxides	NO_x	125.3	40	YES
Particulate Matter	PM	60.6	25	YES
Particulate Matter	$PM_{2.5}$	56.5	10	YES
Sulfur Dioxide	SO_2	5.9	40	NO
Sulfuric Acid Mist	H_2SO_4	0.6	7	NO
Fluorides (as HF)	HF	0.0	3	NO
Lead	Pb	0.0	0.6	NO
Carbon Dioxide	CO_2	1,101,473	75,000	YES
Greenhouse Gases	CO_2e	1,102,850	75,000	YES

c. Step 2: Contemporaneous Decreases in Emissions from the Permanent Shutdown of the Ocotillo Steam Turbines 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.

ii. 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 Units 1 and 2 Steam Turbines and associated cooling towers are presented in Appendix E of the Applicant's application, and summarized in Tables 22, 23, 24, and 25. 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.

d. 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:

i. The increase in Project emissions; and

ii. Decreases in actual emissions from the Units 1 and 2 Steam Turbines.
These are the only contemporaneous and creditable changes at the Ocotillo Power Plant. Because the Applicant is proposing to permanently shut down the existing Unit 1 and 2 Steam Turbines 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 26 is a calculation of the net emissions increase for the Ocotillo Power Plant Modernization Project. From Table 26, the Project will result in a significant emissions increase and a significant net emissions increase in carbon monoxide (CO), PM, PM_{10}, $PM_{2.5}$, and greenhouse gas (GHG) emissions.

TABLE 22: Baseline Actual Emissions for the Ocotillo Power Plant Steam Turbine Unit 1

POLLUTANT		Baseline Heat Input MMBtu	Baseline Emission Rate lb/MMBtu	Baseline Actual Emissions (tpy)
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
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
Greenhouse Gases	CO_2e	609,861	119.0	36,279

TABLE 23: Baseline Actual Emissions for the Ocotillo Power Plant Steam Turbine Unit 2

POLLUTANT		Baseline Heat Input MMBtu	Baseline Emission Rate lb/MMBtu	Baseline Actual Emissions (tpy)
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
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
Greenhouse Gases	CO_2e	634,840	119.0	37,766

Footnotes for Tables 12 and 13
1. The baseline period for all pollutants is the 24-month period from March 2012 to February 2014.

TABLE 24: Total Baseline Actual Emissions for the Ocotillo Power Plant Steam Turbines Units 1 and 2

POLLUTANT		Baseline Heat Input	Baseline Emission Rate	Baseline Actual Emissions
		MMBtu	lb/MMBtu	(tpy)
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
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	73,972
Greenhouse Gases	CO_2e	1,244,701	119.0	74,045

TABLE 25: Total Baseline Actual Emissions for the Ocotillo Power Plant Steam Turbines Units 1 and 2 and the Associated Cooling Towers

POLLUTANT		Unit 1	Unit 2	Cooling Towers	Baseline Actual Emissions
		(tpy)	(tpy)	(tpy)	(tpy)
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	6.7	11.4
Particulate Matter	PM_{10}	2.3	2.4	2.1	6.8
Particulate Matter	$PM_{2.5}$	2.3	2.4	1.3	5.9
Sulfur Dioxide	SO_2	0.2	0.2		0.4
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		73,972
Greenhouse Gases	CO_2e	36,279.0	37,766		74,045

TABLE 26: Net Emissions Increase and PSD Applicability

POLLUTANT		New Project Emissions (tpy)	Creditable Emission Decreases (tpy)	Net Emission Increase (tpy)	Significance Level (tpy)	Over?
Carbon Monoxide	CO	249.9	14.6	235.5	100	YES
Nitrogen Oxides	NO_x	125.3	85.9	39.4	40	NO
Particulate Matter	PM	60.9	8.0	52.9	25	YES
Particulate Matter	$PM_{2.5}$	56.5	5.3	51.2	10	YES
Sulfur Dioxide	SO_2	5.9	0.4	5.5	40	NO
Sulfuric Acid Mist	H_2SO_4	0.6	0.0	0.6	7	NO
Fluorides (as HF)	HF	0.002	0.0	0.0	3	NO
Lead	Pb	0.005	0.000	0.005	0.6	NO
Carbon Dioxide	CO_2	1,101,473	73,972	1,027,501	75,000	YES
Greenhouse Gases	CO_2e	1,102,850	74,045	1,028,805	75,000	YES

Footnotes:

1. In accordance with 40 CFR §52.21(i)(2), since the area is nonattainment for PM_{10}, PSD does not apply to PM_{10} emissions.

e. Conclusions Regarding PSD Applicability.

The Department has determined that the Project will not result in a significant emissions increase for sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and fluorides. Based on the proposed permanent shutdown and retirement of the Ocotillo Steam Turbine Units 1 and 2, the net emission increase for NO_x is below the significant emission rate and PSD review is not triggered for that pollutant. The net emission increases for CO, PM, $PM_{2.5}$, and GHG are above the significant emission rates and PSD review is triggered for only these pollutants. Finally, because the Ocotillo Power Plant is located in an area designated as nonattainment for PM_{10} and VOC, the Project is not subject to PSD review for those pollutants.

f. Conclusions Regarding Nonattainment Area New Source Review Applicability.

The Applicant proposed plant-wide fuel use limits and emission caps in accordance with County Rule 201 which limit the total potential emissions for the entire Ocotillo Power Plant below the nonattainment major source thresholds for PM_{10} and VOC emissions (see Table 41). Therefore, the Department has determined that after the Project the Ocotillo plant is a nonattainment major source for NO_x and a minor source for PM_{10} and VOC, and will not be subject to NANSR for PM_{10} and VOC.

As shown in Table 26, the net emissions increase for NO_x is less than the significant emission rate. Therefore, based on the proposed emission limits in this permit application, this Project is not a major modification for NO_x and is not subject to review for any nonattainment area pollutants.

g. Minor NSR (County) BACT Requirements.

MCAQD Rule 241, §301.2, requires the application of BACT to any modified stationary source if the modification causes an increase in emissions on any single day of more than 150 lbs/day or 25 tons/year of VOC, NO_x, or PM; more than 85 lbs/day or 15 tons/year of PM_{10}; or more than 550 lbs/day or 100 tons/year of CO. BACT is only required for the sources or group of sources being modified. The Provisions of Rule 241 do not apply to new major sources and major modifications to existing major sources subject to the requirements of the PSD program at MCAQD Rule 240.

PSD BACT requirements already apply to CO, PM, $PM_{2.5}$, and GHG pollutants. Therefore, Rule 241 BACT does not apply to these pollutants. The only regulated pollutants that Rule 241 BACT could potentially apply to are PM_{10}, NO_x, and VOC. Based on the hourly mass emission rates listed in Table 9, and assuming that all five new GTs could operate at full load for 24 hours in a day, the GTs alone exceed the Rule 241 daily thresholds and trigger the Rule 241 BACT requirement for these three pollutants. Therefore the permit application included Rule 241 BACT analyses for all new emission units for NO_x and VOC, and the PSD PM and $PM_{2.5}$ BACT analyses will meet the requirement for a Rule 241 PM_{10} BACT analysis.

h. Title V Revision.

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

26. APPLICABLE SIP REQUIREMENTS FOR NONATTAINMENT AREA NEW SOURCE REVIEW:

The Maricopa County applicable state implementation plan (SIP) contains administrative permit processing rules. EPA approved these rules for the issuance of permits for minor source new source review and major source nonattainment area new source review (NANSR) but not for prevention of significant deterioration permits (PSD) in attainment areas. Under a delegation agreement with US EPA, Maricopa County administers the PSD program pursuant to the requirements under 40 CFR

§52.21. The department also follows the requirements of current Maricopa County Air Pollution Control Rule 240 when conducting preconstruction review for major sources for both NANSR/PSD.

The applicable SIP requirements for nonattainment area new source review are found in SIP Rule 21.0—Procedures for Obtaining an Installation Permit. SIP Rule 21 also includes the incorporation by reference of Arizona Administrative Code (ACC) Articles R9-3-301, R9-3-302, R9-3-303, R9-3-304, R9-3-305, R9-3-307, including definitions used and articles referenced in those administrative rules except for four definitions specifically modified in SIP Rule 21(D)(1). AAC Article R9-3-302 specifically addresses NANSR and the terms referenced in the article are defined in AAC Article R9-3-101.

Several provisions contained in the applicable SIP apply to the applicability determination for the APS Ocotillo major modification and differ from 40 CFR 52.21 and Rule 240. These provisions include:

- A "dual source" definition of stationary source found in SIP Rule 21.0(D)(1)(b) and (c) that only applies for sources located in nonattainment areas.
- Definitions of "major source" and "major modifications" that only list volatile organic compounds as a precursor to ozone.
- Definition of "major source" that specifies a nonattainment area major source threshold of 100 tons per year of any pollutant.

Considering the provisions contained in the applicable SIP, the Department has determined that the APS Ocotillo project would not be classified as a major source of nonattainment pollutants. The basis for this determination is described below.

Under a dual source definition, a source is defined in two ways. A source may be either the entire plant (See SIP Rule 21(D)(1)(b)) or an individual emission unit (See SIP Rule 21(D)(1)(c)). Therefore, NANSR only applies to major sources of VOCs and PM_{10}, the nonattainment pollutants per the definitions major source and major modification. As a major source may be either a major individual emission unit and/or a major plant, the potential emissions from the entire plant and separately from each individual emission unit were compared to the 100 TPY threshold.

The APS Ocotillo project will add five additional simple cycle turbines and de-commission two existing steam generating units. Two existing simple cycle turbines will remain on site. The potential emissions from the entire plant and for each individual emission unit were calculated as follows:

- Based on commitments reflected in permit conditions including a proposed combined fuel use limitation for the new GT3-GT7 turbines, a proposed combined fuel use limits on the existing GT1-GT2 turbines, and a plant-wide enforceable cap on PM_{10} emissions, the plantwide potential emissions of VOC and PM_{10} are 42.5 TPY and 63 TPY, respectively.
- Because the proposed fuel use limits are over groups of turbines, the potential emissions for each individual emission were calculated using the maximum allowable operating levels that could occur for each individual emission unit under either normal operations or under startup/shutdown operations.
  - For each new GT3-GT7 turbine individually, the potential VOC and PM_{10} emissions are calculated as 50.4 TPY and 23.7 TPY, respectively.
  - For each of the existing GT1-GT2 turbines, the potential VOC and PM_{10} emissions are 3.1 TPY and 12.4 TPY calculated by allocating the entire GT1-GT2 fuel use limit to a single turbine.

- For each new emergency generator, the potential VOC and PM_{10} emissions are 0.4 TPY and 0.3 TPY calculated assuming 500 hours of operation per year.
- For the new cooling tower, the potential PM_{10} emissions are 1.7 TPY calculated based on 8,760 hours per year.

Therefore, under either a plant wide or individual emission unit basis in the applicable SIP definition of source, the Ocotillo plant would not be classified as a major source of nonattainment pollutants.

27. SCOPE OF THE CONTROL TECHNOLOGY REVIEW:

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

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

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

This EAB decision was upheld by the United States Court of Appeals, 7th Circuit.[1]

When EPA issued guidance in 2011 for conducting control technology reviews for greenhouse gas (GHG) emissions, EPA confirmed that a BACT analysis should not redefine the source's purpose:[2]

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

The EAB has analyzed the redefinition of the source concept in the context of a past permitting proceeding similar to the proposed Ocotillo Modernization Project. In their challenges to a PSD

---

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

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

permit issued for the Pio Pico Energy Center, petitioners asserted before the EAB that EPA had erred in eliminating combined-cycle gas turbines in Step 2 of its BACT analysis for GHG emissions. Like Ocotillo, Pio Pico is a simple cycle gas-fired facility designed to back up renewable generation by providing peaking and load-shaping capability. As the EAB recognized in its Pio Pico decision and consistent with EPA guidance, a permitting authority can consider peaking facilities, intermediate load facilities and base load facilities to be different electricity generation source types. The EAB explained how "plants operating in 'peaking mode' typically remain idle much of the time, but can be started up when power demand increases … and, unlike base load plants, typically use simple-cycle rather than combined-cycle units as well as smaller turbines."[3]

The U.S. EPA has also addressed the issue of whether a peaking facility must consider energy storage such as batteries in the control technology review. For example, in the U.S. EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[4] issued for a peaking facility to be comprised of reciprocating internal combustion engines (RICE), EPA determined that "energy storage cannot be required in the Step 1 BACT analysis as a matter of law." Id. at 1 (explaining that "'incorporating energy storage' in Step 1 of the BACT analysis for a [RICE] resource would constitute the consideration of an alternative means of power production in violation of long-established principles for what can occur in Step 1 of the BACT analysis") (citing Sierra Club v. EPA, 499 F.3d 653, 655 (7th Cir. 2007)). EPA concluded that energy storage, either "to replace all or part of the proposed . . . project," would fundamentally redefine the source. Id. at 1.

Like the Ocotillo Modernization Project, the purpose of the Red Gate project was to provide reliable, rapidly dispatchable power to support renewables and the transmission grid. Because "energy storage first requires separate generation and the transfer of the energy to storage to be effective . . . [it] is a fundamentally different design than a RICE resource that does not depend upon any other generation source to put energy on the grid." Id. Energy storage could not meet that production purpose for the duration or scale needed. Id. at 1-2. As EPA correctly observed, "the nature of energy storage and the requirement to replenish that storage with another resource goes against the fundamental purpose of the facility." Id. at 2.

Similarly, in another PSD permit for a peaking facility for the Shady Hills Generating Station (Jan 2014), this time with natural gas-fired simple cycle units, EPA also concluded that energy storage would not meet the business purpose of the facility and therefore should not be considered in the BACT analysis.[5]

---

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

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

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

Thus the MCAQD concurs with the established EPA practice of considering combined-cycle gas turbines and energy storage as redefining the source for this proposed peaking power plant. Combined-cycle gas turbines and energy storage technologies are further discused in the following BACT review.

28. BACT CONTROL TECHNOLOGIES AND EMISSION LIMITS:

Appendix A of this TSD presents the Applicant's control technology analysis for the proposed simple-cycle GTs, emergency generators, and the hybrid cooling tower. 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, §301.1.

For the PSD BACT analysis for the pollutants CO, PM, $PM_{2.5}$, and GHG, the Department used the 5-step "top-down" method as recommended by EPA. However, it should be noted that the Department must not strictly adhere to the detailed top-down BACT analysis method, because that would unnecessarily restrict the Department's judgment and discretion in weighing various factors before making case-by-case BACT determinations. The top-down 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 Applicant included proposed BACT determinations and supporting information in its permit application, and MCAQD relied on this information in making the proposed BACT determinations. Other materials relied upon by MCAQD for identifying and evaluating available control options include entries in the RACT/BACT/LAER Clearinghouse (RBLC) maintained by the U.S. EPA, information provided by pollution control equipment vendors, and information provided by industry representatives and by other State permitting authorities.

The Maricopa County Rule 241 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.

<u>Combustion Turbine PSD BACT Analysis for GHG</u>:

GHG emissions from natural gas-fired gas turbines include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The federal Mandatory Greenhouse Gas Reporting Requirements under 40 CFR Part 98 requires reporting of greenhouse gas (GHG) emissions from large stationary sources. Under 40 CFR Part 98, facilities that emit 25,000 metric tons or more per year of GHG emissions are required to submit annual reports to EPA. The Applicant used the default emission factors from this rule in its calculations. Because CO_2 emissions account for the vast majority of GHG emissions from these gas turbines, the control technology review for GHG emissions focused on CO_2 emissions.

On August 3, 2015, the U.S. EPA announced the final Clean Power Plan which will regulate GHG emissions from new and existing power plants. Under the final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units in 40 CFR 60 Subpart TTTT, EPA established standards for newly constructed "base load" and "non-base load" fossil fuel-fired stationary combustion turbines. Subpart TTTT is applicable to combustion turbines with a base load heat input rating greater than 250 MMBtu/hr and the capability of selling more than 25 MW-net of electricity to the grid. The emission limitation for new natural gas-fired base load combustion turbines is 1,000 pounds of CO_2 per MWh of gross energy output, and for non-base load natural gas-fired combustion turbines the limit is a fuel-based heat input standard of 120 pounds of CO_2 per MMBtu of heat input.

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

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

   i. The low capacity factors and irregular operating patterns (frequent starting and stopping and operating at part load) of non-base load units make the technical challenges associated with CCS even greater than those associated with base load units.

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

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

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

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

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

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

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

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

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

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

Step 1 of the GHG BACT analysis identifies all available control technologies with practical potential for application to the emission unit. CO_2 emissions result from the oxidation of carbon in the fuel. When combusting natural gas, this reaction is responsible for much of the heat released in the gas turbine, and is therefore unavoidable. There are four potential control options for reducing CO_2 emissions from these gas turbines:

a. The use of low carbon containing or lower emitting primary fuels,

b. The use of energy efficient processes and technologies, including,

  i. Efficient simple cycle gas turbine generators with various combustion technologies,

  ii. Combined cycle gas turbines,

  iii. Reciprocating internal combustion engine (RICE) generators,

c. Good combustion, operating, and maintenance practices,

d. Carbon capture and sequestration (CCS) as a post combustion control system.

Table 27 is a summary of CO_2 BACT determinations and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database and other recent permit decisions. The available technology selected for the control of CO_2 emissions in these BACT analyses was the use of energy efficient processes. Recent BACT emission limits have been expressed on both a pound per megawatt hour of electric output basis (both gross and net output), and also based on mass emission limits expressed in tons per year. The averaging periods for these emission limits are typically long term, 12-month limits. This long term averaging period is also consistent with the proposed standards of performance for CO_2 emissions under 40 CFR 60 Subpart KKKK.

TABLE 27: Recent GHG BACT Limits for Natural Gas Simple-Cycle Turbines

Facility	State	Permit Date	Limit	Units	Averaging Period
Troutdale Energy Center, LLC	OR	Mar-14	1,707	lb CO_2/MWhr (g)	12-month
El Paso Electric Montana Power Station	TX	Mar-14	1,100	lb CO_2/MWhr (g)	5,000 op. hours
EFS Shady Hills LLC	FL	Jan-14	1,377	lb CO_2/MWhr (g)	12-month
Basin Electric Power Coop. Lonesome Creek Gen. Sta.	ND	Sep-13	220,122	ton/year	12-month
Basin Electric Power Coop. Pioneer Generating Station	ND	May-13	243,147	ton/year	12-month
Montana-Dakota Utilities R.M. Heskett Station	ND	Feb-13	413,198	ton/year	12-month
Cheyenne Light, Fuel & Power	WY	Sep-12	1,600	lb CO_{2e}/MWhr (g)	365 day
Pio Pico Energy Center	CA	Nov-12	1,328	lb CO_2/MWhr (g)	720 op. hours
York Plant Holding, LLC Springettsbury	PA	2012	1,330	lb CO_{2e}/MWhr (n)	30-day
LADWP Scattergood Generating Station	CA	2013	1,260	lb CO_{2e}/MWhr (n)	12-month

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

In the following sections, the various control technologies identified in Step 1 are further analyzed.

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

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

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

DLN were retained in Step 1, DLN would be dismissed under Step 2 as technically infeasible.

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

iii. Water Injection.
Good combustion practices including the use of water injection is an effective method for controlling CO and VOC emissions from these gas turbines. Water injection is the most widely used combustion control technology for aero derivative gas turbines and gas turbines with capacities less than 100 MW. The injection of water directly into the turbine combustor lowers the peak flame temperature and reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (e.g., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

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

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

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

c. Combined cycle gas turbines.
The use of combined cycle gas turbines would change the project in such a fundamental way that the plant could not meet its stated purpose of a peaking power plant. In their challenges to a PSD permit issued for the Pio Pico Energy Center, petitioners asserted before the EAB that

EPA had erred in eliminating combined-cycle gas turbines in Step 2 of its BACT analysis for GHG emissions. Like Ocotillo, Pio Pico is a simple cycle gas-fired peaking facility designed to back up renewable generation by providing peaking and load-shaping capability. As the EAB recognized in its Pio Pico decision and consistent with EPA guidance, a permitting authority can consider peaking facilities, intermediate load facilities and base load facilities to be different electricity generation source types. The EAB explained how "plants operating in 'peaking mode' typically remain idle much of the time, but can be started up when power demand increases … and, unlike base load plants, typically use simple-cycle rather than combined-cycle units as well as smaller turbines."

d. Energy storage options evaluated were:

   i. Battery storage

   ii. Liquid air energy storage

   iii. Flywheel energy storage

   iv. Compressed air energy storage

   v. Pumped hydroelectric storage

MCAQD had reviewed the EPA determinations for the Red Gate and Shady Hills Generating Station projects, which concluded that energy storage technologies would not meet the business purpose of those peaking projects and would redefine the source. Additionally, MCAQD has reviewed the information presented by the Applicant on energy storage technologies. MCAQD has determined that energy storage technologies would redefine the source and are not technically feasible for this proposed peaking power plant.

e. Conclusions regarding the Step 2 technically feasible control technology analysis are shown in Table 28 below:

TABLE 28: Summary of the Technically Feasible GHG Control Technologies for the Turbines

Control Technology	Technical Feasibility
The use of low carbon containing or lower emitting primary fuels,	Feasible
The use of energy efficient processes and technologies, including:	
Efficient simple cycle gas turbines	Feasible
Combined cycle gas turbines	Infeasible
Reciprocating internal combustion engines	Feasible
Good combustion and operating practices,	Feasible
Carbon capture and sequestration (CCS).	Infeasible

Steps 3 and 4 of the BACT analysis rank feasible control technologies by effectiveness, and then evaluate the most effective controls considering economic, environmental, and/or energy impacts. The use of RICE generators would have the lowest potential CO_2 emission rate of the technically feasible control options. The use of RICE generators may reduce CO_2 emissions by approximately 5% during normal operation. However, the use of from 28 to 50 RICE generators rather than 5 gas turbine generators as proposed by the applicant may have other issues which could impact the overall efficiency of the power plant and the total CO_2 emissions. Furthermore, while RICE engines may have a small improvement in CO_2 emissions, the use of RICE generators would have other significant environmental impacts. The U.S. EPA has a long standing policy that the use of a control technology may be eliminated if the use of that technology would lead to increases in other pollutants and that those increases would have significant adverse effects that outweigh the benefits from the that technology (see U.S. EPA's *New Source Review Workshop Manual*, page B.49).

While the use of RICE generators may result in a small reduction in CO_2 emissions, the use of RICE generators would result in a substantial increase in NO_x and PM_{10} emissions. The NO_x emission rate representing BACT for RICE engines equipped with selective catalytic reduction (SCR) is typically 5 to 6 ppm which would increase total potential NO_x emissions for the Project by 50 – 100% as compared to the proposed gas turbines. In addition, the total RICE generator PM_{10} emissions for an equivalent of 100 MW electric output would be approximately 5 times higher than for the proposed gas turbines. The location of the power plant is currently designated nonattainment for PM_{10} and ozone. Based on the ozone and PM_{10} nonattainment status of the area, it is appropriate to favor the technology that reduces NO_x and PM_{10} emissions over relatively small and uncertain reductions in GHG emissions, especially when the difference in both NO_x and PM_{10} emissions between the two technologies is so great. EPA Region 9 considered these same types of collateral environmental impacts from RICE generators in Step 4 of the Pio Pico GHG BACT analysis, and concluded that it was appropriate to eliminate RICE engines because of adverse collateral environmental impacts.

After the elimination of RICE generators, high efficiency simple-cycle gas turbines represent the top control option.

As part of the GHG BACT Step 5 process, EPA Region 9 has provided a framework for establishing the GHG BACT limit for gas turbines when considering the variation of turbine efficiency and emissions as a function of operating load in their "Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Pio Pico Energy Center", November 2012, Comment 13. The simple-cycle GTs proposed for the Pio Pico Energy Center are the same units being proposed by the Applicant for this Project. EPA stated that it is not possible to predict the extent of part load operation for the life of the generating facility, and therefore it is inappropriate to establish a GHG permit limit that prevents the facility from generating electricity as intended. For the Pio Pico PSD permit, EPA established the GHG BACT emission limit at a level achievable during the lowest normal operating load, which was 50% load with a resulting GHG BACT limit of 1,328 lb CO_2/MWh of gross electric output. The Ocotillo CTs must have the capability to operate continuously at loads as low as 25% of the maximum load. The Applicant has projected the expected operation of these proposed GTs using a real-time simulation modeling program (Real Time Simulation), the expected number of startup and shutdown events per year, and the expected gross electric generation and load profile. Based on this analysis, the expected operation of the GTs would result in an emission rate of 1,460 lb CO_2/MWh of gross electric output including all periods of operation, including periods of startup and shutdown. The Applicant has proposed a GHG BACT limit of 1,460 lb CO_2/MWh of gross electric output for all periods of operation, including periods of startup and shutdown, based on a 12-operating month rolling average.

It should be noted that petitioners challenged the Pio Pico Permit, stating that the Permit's GHG BACT emission limit is based on the "worst-case operating conditions" and conflicts both with the definition of BACT and EPA precedent. That challenge was reviewed by the U.S. Environmental Appeals Board (EAB). In summary, the EAB upheld the Region's decision, noting that BACT is achieved in the same manner at 50% load as it is at 75% and 100% load (and any other load level), even though the actual GHG emissions resulting from application of BACT may vary at different loads. The EAB also stated that "any assumption that a "BACT-level emission limit" only occurs at 100 percent load ignores the Board's extensive prior precedent set forth at the beginning of this section, which states that a BACT emission limit need not be the most stringent emission limit."

The framework established by EPA Region 9 is also consistent with the U.S. EPA Office of Air and Radiation's document *PSD and Title V Permitting Guidance For Greenhouse Gases*, EPA document EPA-457/B-11-001, March 2011. On page 44, EPA states:

> In setting the BACT limit in Step 5, the permitting authority should look at the range of performance identified previously and determine a specific limit to include in the final permit. In determining the appropriate limit, the permitting authority can consider a range of factors, including the ability of the control option to consistently achieve a certain emissions rate, available data on past performance of the selected technology, and special circumstances at the specific source under review which might affect the range of performance. In setting BACT limits, permitting authorities have the discretion to select limits that do not necessarily reflect the highest possible control efficiencies but that will allow compliance on a consistent basis based on the particular circumstances of the technology and facility at issue, and thus may consider safety factors unique to those circumstances in setting the limits.

After review of the available information, the MCAQD has determined that the use of efficient simple cycle gas turbines and the use of good combustion practices in combination with low carbon containing fuel represents the BACT for the control of GHG emissions from the proposed turbines.

Based on this analysis, the following BACT limits will apply for the control of GHG emissions from the new GTs:

- 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.
- The gas turbines shall achieve an initial heat rate of no more than 8,742 Btu per kilowatt hour of gross electric output at 100% load and a dry bulb temperature of 73 °F.
- CO_2 emissions may not exceed 1,460 lb CO_2/MWh of gross electric output for all periods of operation, including periods of startup and shutdown, based on a 12-operating month rolling average.
- The permittee shall prepare and follow a Maintenance Plan for each GT.

<u>Combustion Turbine PSD BACT Analysis for CO:</u>

The Applicant prepared a summary of available CO control technologies and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database and the South Coast Air Quality Management District's LAER/BACT determinations as Step 1 in the BACT analysis. The reported BACT emission limits for similar turbines range from 6 to 10 ppmdv, corrected to 15% excess oxygen. Several determinations in 2012 concluded that the use of oxidation catalysts and a CO limit of 6.0 ppmdv at 15% O_2 is BACT. This database indicates there are two major control technologies used to control CO and VOC emissions, Good Combustion Practices (GCP) and Oxidation Catalysts (OC).

The BACT Step 2 analysis identifies Technically Feasible Control Technologies. These include the use of GCP and OC as a post combustion control system. The BACT Step 3 ranking of Technically Feasible Control Technologies lists these same two technologies as the most effective control, and therefore they have been selected in Step 4.

The Department has concluded in Step 5 that the use of GCP and OC represents BACT for the control of CO emissions from the proposed GE LMS100 simple-cycle gas turbines. While the Applicant originally proposed a CO BACT limit based on a 3-hr average, the Department has concluded that a 1-hr averaging interval is more appropriate and is consistent with other BACT determined. The following emission limit will apply as BACT for the control of CO emissions from the combustion turbines: CO emissions may not exceed 6.0 parts per million, dry, volume basis (ppmdv), corrected to 15% O_2, based on a 1-hour average, when operated during periods other than startup/shutdown and tuning/testing mode.

Combustion Turbine PSD BACT Analysis for CO - Startup/Shutdown:

The Applicant proposed a CO emission limit of 69.2 lb/hr during turbine startup and shutdown, a definition of startup as “the period between when a unit is initially started and fuel flow is indicated and ending 30 minutes later’, and the definition of shutdown as “the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased”. In addition, the Applicant proposed a limitation of the total number of hours in startup and shutdown mode for GT3 through GT7 combined to not exceed 2,490 hours averaged over any consecutive 12-month period. The Department has reviewed the information provided by the Applicant and has determined that the limits proposed by the Applicant represent BACT for CO during startup and shutdown operations.

Combustion Turbine PSD BACT Analysis for $PM_{2.5}$:

The Applicant prepared a summary of available $PM_{2.5}$ control technologies and BACT emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database as Step 1 in the BACT analysis. The reported BACT emission limits for similar simple cycle turbines range from 0.0053 to 0.01 lb/MMBtu. This database indicates the available technologies for the control of PM emissions from natural gas-fired gas turbines includes the use of Good Combustion Practices (GCP) and low ash / low sulfur fuels.

The BACT Step 2 analysis identifies Technically Feasible Control Technologies. These include the use of GCP and low ash / low sulfur fuels. The BACT Step 3 ranking of Technically Feasible Control Technologies lists GCP plus and low ash / low sulfur fuels as the most effective control, and therefore these technologies have been selected in Step 4 of the BACT analysis.

The Department has concluded in Step 5 that the use of GCP in combination with pipeline natural gas fuel represents BACT for the control of $PM_{2.5}$ emissions from the proposed GE LMS100 simple-cycle gas turbines. The Department has reviewed available stack test data and considered EPA Region 9’s final BACT analysis for the Pio Pico project which concluded that a total PM BACT emission limit of 0.0055 lb/MMBtu would be appropriate. An emission rate of 0.0055 lb/MMBtu is equal to a mass emission rate of 5.34 lb/hr at the rated heat input of 970 MMBtu per hour for the proposed Applicant’s combustion turbines. The addition of the Applicant’s estimated sulfuric acid mist emission rate of 0.06 lb/hr to the PM mass emission rate results in a total PM emission rate of 5.4 lb/hr. Therefore, the Department has concluded that the following emission limit will represent BACT for the control of $PM_{2.5}$ emissions from the combustion turbines: Particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions may not exceed 5.4 pounds per hour (lb/hr), based on a 3-hour average.

Note that a separate startup/shutdown $PM_{2.5}$ BACT limit is not necessary, because emissions of $PM_{2.5}$ are not reduced by any active control device that requires time to begin operation.

Emergency Generator PSD BACT Analysis for GHG:

CO_2 emissions from the diesel-fired IC engine emergency generators result from the oxidation of carbon in the fuel. When combusting fuel, this reaction is responsible for much of the heat released in diesel engines and is therefore unavoidable. The Applicant’s Step 1 analysis indicates there are five potential control options for reducing CO_2 emissions from these diesel generators:

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

After considering available and technically feasible control alternatives and the restricted operation of 500 hours per year, the Department has concluded that the following limits represent BACT for the control of GHG emissions from the emergency generators: CO_2 emissions from each diesel engine generator may not exceed 984.4 tons per year, and the operation of each generator may not exceed 500 hours per year.

Emergency Generator PSD BACT Analysis for CO:

These engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. The CO emission standard for emergency engines greater than 750 hp is 2.61 g/hp-hr (Tier 2 standard). Note that the Tier 4 engine CO emission standard is also 2.61 g/hp-hr.

The Applicant prepared a summary of available CO control technologies and BACT emission limits for diesel-fired IC engine emergency generators based on the U.S. EPA's RACT/BACT/LAER database as Step 1 of the BACT analysis. The reported BACT emission limits have typically been set to the Tier 2/Tier 4 emission limit of 2.61 g/hp-hr.

The BACT Step 2 analysis identifies Technically Feasible Control Technologies. These include the use of Good Combustion Practices (GCP) with Tier 2 engines, and GCP and diesel oxidation catalyst systems in Tier 4 engines. Note that while diesel oxidation catalysts may reduce CO emissions, based on the fact that the Tier 2 and Tier 4 standards have the same CO emission standard, it cannot be concluded that an engine designed to the Tier 4 standard would actually reduce CO emissions as compared to the Tier 2 engine. Therefore, the BACT Step 3 ranking of Technically Feasible Control Technologies lists both Tier 2 and Tier 4 engines as the most effective control, and the Step 4 selection of the most effective controls includes both Tier 2 or Tier 4 engines.

The Department has concluded in Step 5 that the use of GCP and Tier 2 engines represents BACT for the control of CO emissions from the emergency generators. The following BACT emission limit will apply: CO emissions may not exceed 2.61 g/hp-hr, and the operation of each generator may not exceed 500 hours per year. The Permittee shall comply with this emission limit by purchasing an engine certified to meet the emission standards in 40 CFR § 60.4205(c) for the same model year and NFPA nameplate engine power. The engine shall be installed and configured according to the manufacturer's emission-related specifications.

Emergency Generator PSD BACT Analysis for $PM_{2.5}$

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

The Applicant prepared a summary of available $PM_{2.5}$ control technologies and BACT emission limits for diesel-fired IC engine emergency generators based on the U.S. EPA's RACT/BACT/LAER database as Step 1 of the BACT analysis. The reported BACT emission limits have typically set equal to the Tier 2 emission limit of 0.15 g/hp-hr.

The BACT Step 2 analysis identifies Technically Feasible Control Technologies. These include the use of Good Combustion Practices (GCP) with Tier 2 engines, and diesel oxidation catalyst systems in Tier 4 engines. The BACT Step 3 ranking of Technically Feasible Control Technologies lists Tier 4 engines as the most effective control, followed by Tier 2 engines and GCP.

Step 4 of the BACT analysis evaluates the most effective controls and considers economic, environmental, and/or energy impacts. The Applicant conducted a cost effectiveness analysis between the Tier 2 and Tier 4 control technologies, including consideration of the limitation of 500 operating hours per year on these engines. The analysis indicates that the incremental cost effectiveness of Tier 4 engines as a PM BACT control option (based only on the additional capital costs) would be $130,000 per ton of PM controlled. The actual Tier 4 engine costs would be higher due to increased operating and maintenance (O&M) costs. This very high cost demonstrates that the use of Tier 4 engines equipped with diesel oxidation catalysts is not an economically feasible PM and $PM_{2.5}$ control technology option for these limited operation emergency generators. Based on this cost evaluation, the next most effective PM and $PM_{2.5}$ control option is the use of Tier 2 engines.

The Department has concluded in Step 5 that the use of GCP and Tier 2 engines represents BACT for the control of $PM_{2.5}$ emissions from the emergency generators. The following BACT emission limit will apply: $PM_{2.5}$ emissions may not exceed 0.15 g/hp-hr, and the operation of each generator may not exceed 500 hours per year. The Permittee shall comply with this emission limit by purchasing an engine certified to meet the emission standards in 40 CFR § 60.4205(c) for the same model year and NFPA nameplate engine power. The engine shall be installed and configured according to the manufacturer's emission-related specifications.

Cooling Tower PSD BACT Analysis for $PM_{2.5}$

The Applicant prepared a summary of available PM2.5 control technologies and BACT emission limits for cooling towers based on the U.S. EPA's RACT/BACT/LAER database as Step 1 of the BACT analysis. Demisters (i.e., mist eliminators) are the primary identified control technology to limit PM emissions. Demisters can be designed for various levels of drift loss control. The cooling tower drift loss control requirements representing BACT for permits issued since 2007 range from 0.0005% to 0.002%. In addition to the use of high efficiency mist eliminators, available plant cooling options include:

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

All wet systems, including the hybrid systems, have wet cooling towers which are sources of potential PM emissions. Fully dry ACHEs do not use water and can essentially eliminate cooling tower related PM, PM_{10}, and $PM_{2.5}$ emissions.

The BACT Step 2 analysis identifies Technically Feasible Control Technologies, which include technologies listed above. Water treatment methods such as the use of demineralized water are sometimes considered to be potential control technologies. However, demineralizing the makeup water may not significantly change the total dissolved solids (TDS) concentration in the circulating cooling water. And because potential PM, PM_{10}, and $PM_{2.5}$ emissions from cooling towers are a function of the circulating water TDS (NOT the makeup water TDS), the use of demineralized makeup cooling water would not affect the maximum potential emissions from the cooling tower. Rather, demineralizing the makeup water would increase the cycles of concentration which the cooling tower could operate at, but it would not change the maximum TDS concentration in the circulating cooling water.

The BACT Step 3 ranking of Technically Feasible Control Technologies lists the most effective control option as 100% dry systems, followed by hybrid cooling tower that utilizes high efficiency drift eliminators (the highest level of mist control commercially available is 0.0005%).

Step 4 of the BACT analysis evaluates the most effective controls and considers economic, environmental, and/or energy impacts. The Applicant conducted a cost effectiveness analysis between 100% dry and hybrid cooling tower designs. The capital and auxiliary power requirements are much higher for the 100% dry cooling systems. The use of 100% dry cooling reduces the net plant electrical output at an ambient temperature of 105F by 16.1 MW per GT (a 15% reduction), or a total plant derating of approximately 80 MW. This reduction in plant capacity on hot summer days would have a very high cost. The capital costs alone for the hybrid system are estimated at $9,888,000 as compared to $13,813,000 for the 100% dry cooling system. The annualized capital costs are calculated at $336,800. If a 100% dry cooling system eliminated the hybrid cooling system emissions, the cost effectiveness for the use of 100% dry cooling as a BACT control option – based only on the additional capital cost - would be \$62,500 per ton of PM controlled, \$198,000 per ton of PM_{10} controlled, and \$330,000 per ton of $PM_{2.5}$ controlled. These costs do not include the expected lost capacity and energy sales during peak power periods, and these costs do not include the higher auxiliary electric loads required to operate the 100% dry cooling systems. Therefore, the use of 100% dry cooling systems is an economically infeasible BACT control option for the control of PM, PM_{10}, and $PM_{2.5}$ emissions for this Project. Therefore, the Step 4 analysis indicates that the hybrid cooling tower with high efficiency drift eliminators is the most effective control technology.

The Department has concluded in Step 5 that the use of the hybrid cooling tower with high efficiency drift eliminators represents BACT for the control of $PM_{2.5}$ emissions from the cooling tower. The following BACT emission limit will apply: the cooling tower drift eliminators shall be designed for a drift loss of no more than 0.0005% of the total circulating water flow, and the total dissolved solids (TDS) concentration in wet cooling circulation water may not exceed 8,000 parts per million (ppm) on weight basis.

<u>Rule 241 County BACT Analysis for Other Pollutants</u>

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. The analysis considered recent NO_x and VOC BACT determinations in California for similar simple-cycle gas turbines. The Department has determined that the proposed NO_x and VOC emission limits meet the Rule 241 requirements and represent BACT under Rule 241. While the Applicant originally proposed NO_x and VOC Rule 241 BACT limits based on a 3-hr average, the Department has determined that a 1-hr averaging interval is more appropriate.

Table 29 summarizes the final BACT emission limits for the proposed combustion 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 30 summarizes the final BACT emission limits for the new emergency diesel generators; these BACT emissions will be achieved through the use of high efficiency diesel engines, good combustion practices, diesel oxidation catalysts, and combustion of ultra-low sulfur diesel fuel.

TABLE 29: 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 1-hour average.
Nitrogen Oxides (NO_x)	County BACT	2.5 ppmdv at 15% O_2, based on a 1-hour average.
Particulate Matter PM and $PM_{2.5}$	PSD BACT	5.4 pounds per hour, combined filterable and condensable.
Particulate Matter PM_{10}	County 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 1-hour average.
Greenhouse Gases (CO_2e)	PSD BACT	Achieve an initial heat rate of no more than 8,742 Btu/kWh of gross electric output at 100% load. 1,460 lb CO_2/MWh of gross electric output, based on a 12-month rolling hour. Prepare and follow a Maintenance Plan.

TABLE 30: 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. The operation of each generator may not exceed 500 hours per year.
Nitrogen Oxides (NO_x)	County BACT	Tier 2 Emission Standard of 4.77 g NO_x/hp-hr. The operation of each generator may not exceed 500 hours per year.
Particulate Matter PM and $PM_{2.5}$	PSD BACT	Tier 2 Emission Standard of 0.15 g PM/hp-hr. The operation of each generator may not exceed 500 hours per year.
Particulate Matter PM_{10}	County BACT	Tier 2 Emission Standard of 0.15 g PM/hp-hr. The operation of each generator may not exceed 500 hours per year.
Volatile Organic Compounds (VOC)	County BACT	Tier 2 Emission Standard of 0.2 g NMHC/hp-hr. The operation of each generator may not exceed 500 hours per year.
Greenhouse Gases (CO_2e)	PSD BACT	Carbon dioxide (CO_2) emissions may not exceed 984.4 tons per year. The operation of each generator may not exceed 500 hours per year.

29. EMISSIONS FOR EXISTING TURBINES, GENERATOR, AND GASOLINE STORAGE TANK:

Table 31 summarizes the total potential emissions for the existing gas turbines at the Ocotillo Power Plant, based on the requested fuel usage limits. Table 32 summarizes the total potential emissions for the existing propane-fired Generac 125 hp emergency engine at the Ocotillo Power Plant.

The Ocotillo plant also contains a 2,000 gallon gasoline storage tank, with an allowable permitted throughput limitation of 120,000 gallons per year. Potential VOC emissions based on the U.S. EPA's TANKS program, Version 4.0.9d (which is based on the equations from AP-42, Section 7.1, Organic Storage Tanks), is 742 pounds per year, equal to 0.37 tons per year.

The emissions from these units are added to the emissions from the new Project emission units and summarized in Table 44 to determine the major source status of the facility.

TABLE 31: Summary of Potential Emissions for Existing Combustion Turbines

Pollutant		Normal Operation					
		Emission Factor[1] lb/MMBtu	Heat Input MMBtu/hr	Estimated Operation	Potential to Emit Each Turbine		Potential to Emit, Both Turbines (tpy)
					lb/hr	(tpy)	
Carbon Monoxide	CO	0.082	915	1,600	75.03	60.0	120.0
Nitrogen Oxides	NO_x	0.320	915	1,600	292.80	234.2	468.5
Particulate Matter	PM	0.0083	915	1,600	7.55	6.0	12.1
Particulate Matter	PM_{10}	0.0083	915	1,600	7.55	6.0	12.1
Particulate Matter	$PM_{2.5}$	0.0083	915	1,600	7.55	6.0	12.1
Sulfur Dioxide	SO_2	0.0006	915	1,600	0.55	0.4	0.9
Vol. Organic Cmpds.	VOC	0.0021	915	1,600	1.92	1.5	3.1
Sulfuric Acid Mist	H_2SO_4	0.00006	915	1,600	0.055	0.04	0.1
Fluorides (as HF)	HF		915	1,600	0.000	0.00	0.0
Lead	Pb	5.0E-07	915	1,600	0.00046	0.000	0.0
Carbon Dioxide	CO_2	117.0	915	1,600	107,033	85,626	171,253.0
Greenhouse Gases	CO_{2e}	117.1[2]	915	1,600	107,144	85,715	171,429.8

[1] Emission factors taken from the EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, 5th Editions, Table 3.1-1 and 3.1-2a.

[2] The following emission factors and CO_{2e} factors for greenhouse gases including CO_2, N_2O, and CH_4 are from 40 CFR 98, Tables A-1, C-1, and C-2

Pollutant	Natural Gas		
	Emission Factor	Total GHG Emission Factor	
	lb/MMBtu	CO_{2e} Factor	lb/MMBtu
Carbon Dioxide	116.98	1	116.976
Methane	0.0022	25	0.055
Nitrous Oxide	0.00022	298	0.066
Total GHG Emissions as CO_{2e}			117.1

TABLE 32: Summary of Potential Emissions for Existing Emergency Engines

Pollutant		Emission Factor lb/MMBtu	Heat Input MMBtu/hr	Emission Factor g/hp-hr	Power Output hp	Potential Emissions	
						lb/hr	(tpy)
Carbon Monoxide	CO	NA	NA	129.1	125	35.55	8.89
Nitrogen Oxides	NO_x	NA	NA	4.32	125	1.19	0.30
Particulate Matter	PM	0.01941	1.49	NA	NA	0.03	0.01
Particulate Matter	PM_{10}	0.01941	1.49	NA	NA	0.03	0.01
Particulate Matter	$PM_{2.5}$	0.01941	1.49	NA	NA	0.03	0.01
Sulfur Dioxide	SO_2	0.000588	1.49	NA	NA	0.0009	0.0002
Vol Org Cmpds	VOC	NA	NA	0.20	125	0.06	0.01
Sulfuric Acid Mist	H_2SO_4	NA	NA	3.2E-04	125	0.0001	0.0000
Fluorides	F	NA	NA	NA	NA	0	0
Lead	Pb	NA	NA	NA	NA	0	0
Carbon Dioxide	CO_2	NA	NA	750.9	125	206.7	51.7
Greenhouse Gases	CO_2e	NA	NA	753.6	125	207.5	51.9

Footnotes:

1. Potential emissions are based on 500 hours per year of operation.
2. The CO, NO_x, and VOC (THC) emission rates are based on manufacturer's data.
3. PM and SO_2 emissions are based on LPG fuel flow rate of 69.18 lb/hr, a heat content of 21,561 Btu/lb HHV, and AP-42 gas fired 4-stroke rich burn engine emission factors.
4. Sulfuric acid mist emissions are based on 10% conversion of SO_2 to SO_3 in the flue gas.
5. 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.

30. AIR IMPACT ANALYSIS:

The Applicant developed a modeling protocol that was reviewed by MCAQD and EPA Region 9 and approved. The Applicant also submitted a detailed modeling report as part of the permit application. The modeling procedures and results are summarized below:

a. Modeling Basis:

As part of this Title V and PSD construction permit application, a PSD air quality dispersion modeling analysis has been prepared for the two criteria pollutants that trigger PSD review, carbon monoxide (CO) and particulate matter less than or equal to 2.5 microns ($PM_{2.5}$). This analysis demonstrates that the Project does not result in an air quality impact above the Significant Impact Levels (SILs), and therefore does not cause or contribute to an exceedance of any National Ambient Air Quality Standards (NAAQS) or PSD increment. The National Air Quality Standards (NAAQS), Class II PSD increments, and Class II Significant Impact Levels ("SILs") are summarized in Table 33.

The procedures used for all air quality impact analyses comply with relevant EPA and Maricopa County guidance. EPA guidance for performing air quality analyses is described in Chapter C of EPA's "New Source Review Workshop Manual", Draft - October 1990, in EPA's "Guideline on Air Quality Models", 40 C.F.R. Part 51, Appendix W in EPA's "AERMOD Users Guide" and related addendums, and in EPA's "AERMOD Implementation Guide", updated March 19, 2009. In addition, EPA has developed updated $PM_{2.5}$ analysis guidance and specific 1-hr NO_2 and SO_2 NAAQS modeling analysis guidance.

The air quality analysis supplied by the applicant, with which the County agrees, presents an overview of the modeling procedures used, discusses the EPA approved near-field dispersion model, the meteorological data processing procedures, the development of the receptor network, the Good Engineering Practice (GEP) stack height analysis and generation of building downwash parameters for the facility, and the emissions and stack parameter data that were modeled. It also presents the dispersion modeling results, and compares them to the SILs, and when necessary, the NAAQS and PSD increments.

A PSD air quality impact analysis is required for the two criteria pollutants that trigger PSD review, CO and $PM_{2.5}$. The analysis included the following components:

- An analysis of existing background monitoring concentrations relative to the NAAQS to confirm that significant impact levels (SILs) can be used in the 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 and Arizona Ambient Air Quality Standards (NAAQS/AAAQS);
- 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.

Standard PSD air quality analysis requirements do not necessitate an analysis for criteria pollutants that do not trigger PSD review. However, MCAQD requested that the Applicant perform facility-wide NAAQS analyses for the criteria pollutants NO_2 and SO_2 (the SO_2 analyses also addresses Maricopa County Rule 32F requirements).

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. As noted earlier, the Ocotillo plant after the Project will be classified as a minor nonattainment source for PM_{10} and VOC, and the net emission increase for NO_x is less than 40 tpy, therefore the Project does not trigger nonattainment NSR permitting requirements for NO_x, PM_{10}, and ozone including air quality analysis.

TABLE 33: Significant Impact Levels, NAAQS, and PSD Class II Increments. (μg/m^3)

Pollutant	Averaging Period	Class II SIL	NAAQS	PSD Class II Increment
Carbon Monoxide (CO)	8-hour	500	10,000	n/a
	1-hour	2000	40,000	n/a
Particulate Matter ($PM_{2.5}$)	Annual	0.3	15	4
	24-hour	1.2	35	9

b. Dispersion modeling:

The AERMOD model (version 15181) was used for the air quality analyses, with the regulatory default option set. AERMOD is a steady-state plume dispersion model that simulates transport and dispersion from multiple point, area, or volume sources based on an up-to-date characterization of the atmospheric boundary layer. AERMOD uses Gaussian distributions in the vertical and horizontal for stable conditions, and in the horizontal for convective conditions; the vertical distribution for convective conditions is based on a bi-Gaussian probability density function of the vertical velocity. For elevated terrain AERMOD incorporates the concept of the critical dividing streamline height, in which flow below this height remains horizontal, and flow above this height rises up and over terrain. AERMOD also uses the advanced PRIME algorithm to account for building wake effects.

The regulatory default option requires the use of terrain elevation data, stack-tip downwash, sequential date checking, and does not permit the use of the model in the SCREEN mode. In the regulatory default mode, pollutant half-life or decay options will not be employed. These regulatory default options were employed for this AERMOD analysis.

AERMOD incorporates both rural and urban processing options, which affect the dispersion rates used in calculating ground-level pollutant concentrations. Based on a land use analysis, the majority of land use within 3 km of the site is urban. Therefore, the AERMOD modeling was performed using urban settings. The urban option population value used was 2,046,000.

c. Emission and Stack Data.

Tables 9 and 10 present emissions for the proposed GTs. Because the emission rates vary with load, a modeling analysis of various operating loads and ambient temperatures (a load screening analysis) was performed. The stack temperatures and flow rates used for the 100%, 75%, 50%, and 25% loads were the minimum values at each load across the range of ambient temperatures. Because emissions are directly related to heat input rates, normalized emissions of 1.0, 0.78, 0.59, and 0.38 were used for the four load scenarios, based on the relative heat input at these four loads. Table 34 summarizes the results of this load screening analysis using the model predicted "highest first high" concentrations across the complete 5 year meteorological data set. Table 34 demonstrates that the 100% load condition results in the maximum impacts for all averaging intervals, therefore it was used for the subsequent $PM_{2.5}$ modeling analysis. For the CO and NO_2 analyses, because the maximum short-term emission rates occur during startup /shutdown operation, the 25% load stack parameters were used to best simulate startup/shutdown turbine conditions and conservatively determine the CO ambient impacts. While there are two emergency generators, they will not be simultaneously operated for testing or maintenance, therefore only one was modeled as operating at any given time. In addition, the scheduled testing of these generators was limited to 2 hours duration between the hours of 8am to 2pm, and the emission factor option in AERMOD was used to model these hours of operation.

Table 35 presents a summary of the 100% load stack parameters and the emission rates that were modeled for the new GTs and cooling tower.

TABLE 34: Load Screening Modeling Results

Load Level	Annual Impact	1-Hr Impact	8-Hr Impact	24-Hr Impact
100%	0.034	3.86	0.96	0.43
75%	0.032	3.32	0.85	0.38
50%	0.029	2.73	0.70	0.31
25%	0.026	1.96	0.53	0.24

TABLE 35: Gas Turbine, Emergency Generator, and Cooling Tower Emissions, and Stack Parameters

Source ID	Source Description	Easting (X)	Northing (Y)	Base Elevation	Stack Height	Temp.	Exit Velocity	Stack Diameter	CO	$PM_{2.5}$
		(m)	(m)	(ft)	(ft)	(°F)	(fps)	(ft)	(lb/hr)	(lb/hr)
GT3	CT3-LMS100	414841	3698721	1172	85	771	115	13.5	69.2	5.4
GT4	CT4-LMS101	414841	3698774	1172	85	771	115	13.5	69.2	5.4
GT5	CT5-LMS102	414840	3698827	1172	85	771	115	13.5	69.2	5.4
GT6	CT6-LMS103	414840	3698880	1172	85	771	115	13.5	69.2	5.4
GT7	CT7-LMS104	414840	3698932	1172	85	771	115	13.5	69.2	5.4
GTCT C1	CoolTwr Fan 1	414901	3698922	1171	40	87.5	33.4	30	NA	0.039
GTCT C2	CoolTwr Fan 2	414917	3698922	1171	40	87.5	33.4	30	NA	0.039
GTCT C3	CoolTwr Fan 3	414933	3698923	1171	40	87.5	33.4	30	NA	0.039
GTCT C4	CoolTwr Fan 4	414950	3698923	1171	40	87.5	33.4	30	NA	0.039
GTCT C5	CoolTwr Fan 5	414966	3698923	1171	40	87.5	33.4	30	NA	0.039
GTCT C6	CoolTwr Fan 6	414983	3698923	1171	40	87.5	33.4	30	NA	0.039
EMERG	Emergency Generator	414911	3698778	1171	16	794	185	1.5	21.6	1.24

Notes:

The GT3-GT7 stack flow rates are for 100% load conditions. When modeling for CO impacts, 25% load stack parameters were used to better represent the startup/shutdown stack conditions that match the highest CO emission rate scenario. The 25% load stack parameters include an exhaust temperature of 854 degrees F and an exit velocity of 60 fps.

d. PSD Air Quality Analysis Results:

Because the new GTs may begin operation before the existing steam boiler structures are completely dismantled, two sets of BPIP-PRIME analyses were performed, both with and without the existing steam boiler structures. The calculated building downwash parameters are the same for these two BPIP-PRIME analyses, indicating that the steam boiler existing structures are not the controlling structures for the new emission units and the AERMOD predicted impacts for the new emission units are not affected by these existing structures.

The Project-only impacts (i.e., the impacts from the proposed GTs, emergency generators, and cooling tower) are summarized in Table 36. All Project impacts are below the Significant Impact Levels, therefore the Project impacts are not significant and a cumulative NAAQS and PSD increment analysis is not required.

TABLE 36: Significant Impact Modeling Results for the New Emissions Units. (μg/m^3)

Pollutant	Averaging Interval	Highest Modeled Conc.	SILs	Impacts Above SIL?
CO	8-hour	60.5	500	No
	1-hour	343	2,000	No
$PM_{2.5}$	Annual	0.07	0.3	No
	24-hour	1.00	1.2	No

e. County Requested NAAQS Analysis Results:

In addition to the PSD required modeling for $PM_{2.5}$ and CO, the Department requested that the Applicant conduct facility-wide NAAQS modeling for SO_2, NO_2, CO, and $PM_{2.5}$. The facility-wide SO_2 modeling is also used to demonstrate compliance with Maricopa County SIP Rule 32 maximum SO_2 ambient concentrations. The 1-hour, 24-hour and 72-hour Rule 32 ambient limits are 850 μg/m^3, 250 μg/m^3 and 120 μg/m^3, respectively. Because a 72-hour concentration is not output by AERMOD, the 24-hour modeled concentration was used for the 72-hour Rule 32 analysis (this is conservative because the 24-hour concentration will be higher than the 72-hour concentration).

The Project does not trigger PSD-review for NO_2, however a facility wide NO_2 NAAQS analysis was performed. The Plume Volume Molar Ratio Method (PVMRM) option in AERMOD was used to account for the after stack conversion of emitted NO_X to downwind NO_2. This option requires an ozone data file. Ozone concentrations from the three nearby MCAQD SLAMS monitoring stations were used to compile a conservative background ozone data set. The ozone data include periods of missing data at some stations, because they were operated as seasonal ozone monitors in 2009 and early 2010. Therefore, the AERMOD "MHRDOW" monthly and hour of day varying background ozone option was used. The highest ozone concentration observed at any of these three stations for each hour of the day by month was selected from the 5 year data period from 2009 through 2013. This is a conservative method of incorporating background ozone concentrations into AERMOD's PVMRM option. The use of PVMRM also requires use of an in-stack ratio (ISR) for each source. EPA's recommended default ISR of 0.5 was used for all NO_X emission sources. In accordance with EPA's guidance on modeling intermittent sources, the emergency engines were not be included in the 1-hour NO_2 (and 1-hour SO_2) modeling, but were included in all other pollutants and averaging period modeling.

The facility wide AERMOD predicted ambient concentrations are summarized in Table 37, along with the background concentration data and the NAAQS. The short-term CO and SO_2

impacts (not including the 1-hour SO_2 and 1-hour NO_2 impacts, which are based on the design concentrations for those pollutants) are the highest-second-high concentrations from any single year of meteorological data. All facility impacts, when added to the background concentrations, are below the NAAQS and demonstrate compliance with the NAAQS and the Rule 32 concentration limits.

Table 37 – Facility NAAQS and Rule 32 Modeling Results (ug/m^3)

Pollutant	Averaging Interval	Cumulative Impact	Background	Total	NAAQS (Rule 32 Limit)	% of NAAQS
CO	8-hour	1231	1832	3063	10,000	31%
	1-hour	1733	2519	4252	40,000	11%
NO_2	Annual	0.7	37	38	100	38%
	1-hour	30.4	115	145	188	77%
SO_2	Annual	0.06	3	3	80	4%
	24-hour	0.16	21	21	365	6%
	3-hour	0.4	21	21	1,300	2%
	1-hour	0.2	21	21	196 (850)	11%
$PM_{2.5}$	24-hour	0.9	18	18.9	35	54%
	Annual	0.3	8.9	9.2	15	61%

Note: The 24-hour and 72-hour Rule 32 SIP ambient concentration limits are 250 µg/m3 and 120 µg/m3, respectively. The 24-hour modeled impacts are compared to the lower of these Rule 32 limits to conservatively demonstrate compliance.

31. ADDITIONAL IMPACT ANALYSIS:

The Prevention of Significant Deterioration (PSD) program requires an additional impact analysis for pollutants that trigger PSD review (for this Project, those pollutants are CO and $PM_{2.5}$). The purpose of this analysis is to assess the potential impact the proposed project will have on visibility, soils, and vegetation, as well as the impact of general commercial, residential, and industrial growth associated with the proposed project.

a. Analysis on Soils, Vegetation, and Visibility:

The Applicant's analysis of CO and $PM_{2.5}$ impacts on vegetation and soils of commercial or recreational value was based on an inventory of vegetation and soils in the Project area, and a comparison of AERMOD predicted air quality impacts of the Project to specified effects thresholds.

The EPA Environmental Appeals Board (EAB) has discussed in the Indeck-Elwood LLC PSD Appeal No. 03-04, September 27, 2006, and found that the PSD vegetation and soils analysis procedures in EPA's 1990 Draft New Source Review Workshop Manual (NSR Manual) provide a proper framework for the analysis. The NSR Manual states that an analysis of soil and vegetation air pollution impacts "should be based on an inventory of the soil and vegetation types found in the impact area." The Project will not result in significant impacts for CO and $PM_{2.5}$, and the locations of the maximum impacts are very close to the Project ambient air boundary. Therefore, the impact and inventory area that should be analyzed is the immediate vicinity of the Ocotillo Plant.

There are no commercial crops located in the immediate vicinity of the Ocotillo plant. The closest crop land is located approximately 1.5 km to the northeast of the plant, and the Project CO and $PM_{2.5}$ air quality impacts at that distance (and at the fence line) are insignificant. The ASU Karsten golf course is located immediately to the west and north of the Ocotillo power plant; the Applicant donated 100 acres of land for the course in the 1970s, and the course opened in 1989. The air quality impacts of the current Ocotillo plant has not interfered with the golf course vegetation since operations began, and the Project air quality impacts have also been shown to be insignificant. Therefore, it is not anticipated that the Project will effect commercial or recreational vegetation in the area.

A soil survey for the area surrounding the Ocotillo plant was performed using the US Department of Agriculture Web Soil Survey (WSS) at http://websoilsurvey.nrcs.usda.gov/app/. Appendix A of the modeling report presents the detailed survey results. The survey results indicate that the predominate soil types located within an approximately 3 mile square area centered on the Ocotillo plant include Laveen, Avondale Clay, and Gilman loams, and general alluvial soil types. These are common soil types for the area, and do not represent any unique, sensitive soils that would be impacted by the Project.

As part of the Applicant's Application for a Certificate of Environmental Compatibility ("CEC") to the Arizona Corporation Commission ("ACC"), the Applicant submitted an inventory and analysis of fish, animal, and plant life within 3 miles of the Ocotillo Plant (CEC Exhibit C – Special Status Species and Species of Concern) was submitted. The overall conclusions of the CEC analysis are that within the surrounding study area, the biotic environment has experienced high levels of disturbance with urban development in nearly the entire area. The Ocotillo site is a disturbed industrial area. Future operations would not change significantly from existing ones and there are no anticipated additional impacts on special status species or habitats.

The air quality impacts from the Project were compared to vegetation and soils threshold impact criteria in EPA's A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals, December 12, 1980, EPA 450/2-81-078. This document contains screening levels for CO impacts, but not $PM_{2.5}$ impacts. The CO screening threshold for sensitive vegetation is listed as 1000 ppm (1,200,000 ug/m3) for a 1 week exposure (averaging interval). The Project and facility-wide CO impacts are orders of magnitude lower than this threshold. In addition, because the Project is fired using natural gas, there are no appreciable emissions of metals and Project impacts would be far below any listed screening thresholds for soils and vegetation effects of metals.

Information on the sensitivities of vegetation to NO_2 ambient concentrations is also found in EPA's "Air Quality Criteria for Oxides of Nitrogen, Summary of Vegetation Impacts" Volume II, August 1993 (EPA 600/8-91/049bF). For susceptible plant species, 1-hr NO_2 exposures to approximately 7,500 ug/m^3 can cause 5% foliar injury. Even though the Project does not trigger PSD review for NO_x, a facility wide modeling analysis indicated that maximum 1-hr impacts including background are 145 ug/m^3. This maximum ambient concentration is far lower than the susceptible plant species effects threshold.

EPA's draft NSR Manual states that "For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary [NAAQS] will not result in harmful effects." The NAAQS secondary standards are intended to protect public welfare, including the consideration of economic interests, vegetation, and visibility. Neither the Project impacts, nor the Ocotillo facility-wide impacts, are greater than the primary or secondary NAAQS.

In summary, based on an inventory of soils and vegetation and comparison of Project air quality impacts to the NAAQS and various screening threshold, the Department has concluded that the Project and the emission of specified pollutants will not have an adverse impact on soils and vegetation.

b. Associated Growth and Secondary Emissions:
The emissions resulting from residential, commercial, and industrial growth associated with, but not directly a part of the project, must also be considered when conducting the air quality analysis. Given the large local population and the limited construction related activities associated with this Project, the construction associated with the Project will not have a significant impact to the local population. Further, since the Ocotillo Power Plant is an existing operation, the employees required to operate the facility are already largely hired and available, so that further impacts to the local area will be insignificant. Local municipal services will not be adversely impacted by this Project. Therefore, the Project is not expected to have a measurable effect on the residential, commercial, or industrial growth of the area.

c. Analysis on visibility:
Based on consultations with MCAQD and the Arizona Department of Environmental Quality (ADEQ), a Class II area visibility analysis was performed by the Applicant for the three nearby parks, the City of Phoenix Camelback Mountain and South Mountain Parks and the Tres Rios wetlands area. VISCREEN was used to assess visibility impacts at these locations. Note that there are no established adverse effects thresholds for Class II visibility analyses.

The VISCREEN model is a screening technique used to estimate the mass of pollutant in the atmosphere and its ability to scatter or absorb light and, therefore, to affect visibility. The VISCREEN model calculates rudimentary scattering and absorption coefficients and these values are compared to screening threshold levels to determine the potential magnitude and type of coherent plume visibility impairment. Two measures of potential plume effects are used. One is a measure of plume contrast, which is the change in light extinction coefficient between views against a background feature (either sky or terrain) and views against the plume. The other measure is delta E, the total color contrast, which takes into account plume intensity, color, and brightness. If the plume is brighter than its background, it will have a positive contrast. If the plume is darker than its background, it will have a negative contrast. VISCREEN assumes that a terrain object is black, which maximizes the contrast. VISCREEN can be run with simple "worst-case" meteorology, referred to as a "Level 1" analysis, or in a more refined mode based on an analysis of actual meteorological conditions, referred to as a "Level 2" analysis.

The emissions used for the VISCREEN analysis are based on a worst-case 24-hr scenario that included unlimited startup emissions for NO_x (31.4 lb/hr for each GT) and full load emissions for $PM_{2.5}$ (5.4 lb/hr for each GT) for all 5 GTs concurrently. Given the intermittent nature of the emergency generators, emissions from emergency generators are not included in the analysis. Other VISCREEN inputs include the default particle characteristics and plume-source-observer angle, and an ozone background concentration of 0.077 ppm based on the maximum 8-hr average ozone at the Tempe monitoring station in 2013.

The ADEQ monitors visibility in the Phoenix area and reports data at the web page http://www.phoenixvis.net/vis-index.aspx. Data from 2013 indicates that the measured visibility for the majority of the days (226 out of 365) was in the Good category (ranging from 15 to 20 deciviews). Conservatively using the best visibility value in this range (15 deciviews), and converting it to visual range, the existing background visual range in the Phoenix area is calculated at 90 km. This visual range was used for the Class II area VISCREEN analyses.

Because a similar near-field visibility analysis was performed for the Class I Superstition Mountain Wilderness area, and Level 2 meteorological data was developed for that analysis, Level 2 meteorological data was also used for the Class II area VISCREEN analyses. The Level 2 assessment was based on 5 years of hourly ISC meteorological data for Sky Harbor airport processed by ADEQ, along with the Iowa Department of Natural Resources "VISCREEN Tool" spreadsheet analysis tool (which calculates the frequency of occurrence data needed to conduct the Level-2 VISCREEN analysis in accordance with the VISCREEN user's manual and guidance documents). Table 38 presents the VISCREEN parameters and observer geometries that were used for the Level 2 analyses at these three Class II areas.

TABLE 38: VISCREEN Parameters for Class II Visibility Analysis:

	Camelback Mountain	South Mountain	Tres Rios Wetlands
Minimum Distance (km)	10	12	32
Maximum Distance (km)	13	27	34
Sector for Transport of Emissions from Source to Area	325 to 340 degrees	230 to 250 degrees	260 to 265 degrees
Level 2 Stability Class	E	F	E

Table 39 presents the VISCREEN Class II analysis results for "Inside the Class II area". There are no specific impact thresholds that apply to a Class II visibility modeling analysis.

TABLE 39: VISCREEN Class II Visibility Analysis Results

	Camelback Mountain	South Mountain	Tres Rios Wetlands
Maximum Delta E	1.64	5.72	0.47
Maximum Contrast	0.008	0.059	0.004

d. Class I Area Analysis:

The PSD regulations require that major sources and major modifications which may affect a Class I area (i.e., are generally located within 100 km of a Class I area) must notify the Federal Land Managers (FLMs) of the project. The permit applicant typically performs a Class I PSD Increment analysis and an Air Quality Related Values (AQRVs) analysis for any AQRVs that the FLMs have identified for the specific Class I area(s). In addition, projects with large emission increases that are located beyond 100 km but within 300 km from a Class I area may also be requested to conduct an impact analysis by the FLMs. The FLM's Air Quality Related Values Work Group (FLAG) Phase I Report – Revised (FLAG 2010) provides guidance on methodologies for conducting Class I air quality impact analyses.

The four Class I areas located within 100 km of the Project include the Superstition Wilderness Area (WA), the Sierra Ancha WA, the Pine Mountain WA, and the Mazatzal WA. All of the other Class I areas in Arizona are located more distant than 100 km but within 300 km of the Project location.

The Ocotillo Project triggers PSD review for the criteria pollutants CO and $PM_{2.5}$. There are no Class I PSD increments for CO, and CO does not contribute to visibility or other AQRV degradation, therefore Class I analyses are not required for CO. Class I PSD $PM_{2.5}$ increment analyses were performed, as well as any required AQRV analyses.

i. Class I $PM_{2.5}$ PSD Increment Analysis:
Based on discussions between MCAQD and ADEQ, it has been determined that there have not been any construction-related $PM_{2.5}$ emission increases at major sources that have been permitted since the major source baseline date, and that the only $PM_{2.5}$ minor source increment date that has been triggered in Arizona is for the Cochise County baseline area by the Southwestern Power Bowie PSD project. That project did not result in an annual $PM_{2.5}$ impact greater than 0.3 $\mu g/m^3$ in any Class I area (one of the triggering criteria for establishing the minor source baseline date in Class I areas), but because the Chiricahua National Monument and Chiricahua WA are also located in Cochise County, the minor source baseline dates have been triggered in those Class I areas. For all other Class I areas in Arizona, the $PM_{2.5}$ minor source baseline date has not been triggered. The Ocotillo Project PSD permit application triggers the $PM_{2.5}$ minor source baseline date in the Maricopa County baseline area and those portions of the Superstition WA and the Mazatzal WA that are contained within Maricopa County.

The highest predicted annual and 24-hr $PM_{2.5}$ impacts from the Ocotillo Project emission units at either the Superstition receptors or the 50 km receptor ring are 0.016 ug/m^3 and 0.06 ug/m^3, respectively. These impacts are less than the annual and 24-hr $PM_{2.5}$ PSD Class I SILS of 0.2 and 0.3 ug/m^3, and the annual and 24-hr $PM_{2.5}$ PSD Class I increments of 1 ug/m3 and 2 ug/m^3, respectively. Even when adding the highest predicted annual and 24-hr $PM_{2.5}$ impacts from the Bowie Project of 0.006 ug/m3 and 0.076 ug/m3, respectively, the total impacts are appreciably lower than the PSD increments. Therefore, this analysis demonstrates that the Project will not cause or contribute to an exceedance of the Class I $PM_{2.5}$ PSD increments.

ii. Near-field Visibility AQRV Analysis:
VISCREEN was used to assess near-field visibility impacts in the Superstition WA. The VISCREEN model is a screening technique used to estimate the mass of pollutant in the atmosphere and its ability to scatter or absorb light and, therefore, to affect visibility. The VISCREEN model calculates rudimentary scattering and absorption coefficients and these values are compared to screening threshold levels to determine the potential magnitude and type of coherent plume visibility impairment. Coherent plume impacts occur when a visible plume or colored layer is visible against the sky or distant terrain features. Coherent plume impacts may occur in areas that are close to a source of pollutants, while uniform haze may occur further downwind. Two measures of potential plume effects are used. One is a measure of plume contrast, which is the change in light extinction coefficient between views against a background feature (either sky or terrain) and views against the plume. The other measure is delta E, the total color contrast, which takes into account plume intensity, color, and brightness.

The VISCREEN analysis results inside the Class I area include a maximum delta E value of 1.65, and a maximum contrast value of 0.014. Both of these values are below the screening criteria values of 2.00 for delta E and 0.05 for contrast, therefore the Class I screening criteria will not be exceeded.

iii. Near-field Nitrogen Deposition AQRV Analysis:
Even though the Project does not trigger PSD review requirements (including Class I analysis requirements) for the pollutants NO_X and SO_2 (the Project net emission increases of those pollutants are below the Significant Emission Rates of 40 tpy), a near-field nitrogen and sulfur deposition AQRV analysis was performed.

The final nitrogen and sulfur deposition rates are 0.0033 kg/ha-yr and 0.0002 kg/ha-yr. These deposition rates are below the Deposition Analysis Thresholds (DATs) for western

Class I areas of 0.005 kg/ha-yr. Therefore, the Project impacts are below the screening thresholds for nitrogen and sulfur deposition at the portion of the Superstition Class I area that is within 50 km of the Project.

The Applicant's detailed modeling results may be found in the attached document:

2015_10_AQ
Modeling & EJ Submit

In summary, the Department has determined that the air quality analysis results comply with the PSD and County requirements, and demonstrate that the Project will not cause or contribute to a violation of any NAAQS or PSD increment.

32. NEW PERMIT CONDITIONS:

Tables 40 through 43 summarize the 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: Continuous Emission Monitoring (CEM) data for NO_x, CO, and carbon dioxide (CO_2) emissions; fuel use data; PM_{10}, $PM_{2.5}$, and VOC emission factors derived from the most recent stack test data; fuel specification data from the natural gas pipeline supplier; and data on the number of startup/shutdown events.

TABLE 40: Rolling 12-Month Average Limits

<table>
<tr><th>Emissions Unit(s)</th><th>SO_2 (tpy)</th><th>NO_x (tpy)</th><th>CO (tpy)</th><th>PM_{10} (tpy)</th><th>$PM_{2.5}$ (tpy)</th><th>VOC (tpy)</th><th>CO_2e (tpy)</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</td><td>54.9</td><td>43.1</td><td>1,099,504</td></tr>
<tr><td>EG1 – EG2 Emergency Generators</td><td>0.02</td><td>10.8</td><td>0.6</td><td>0.83</td><td>1,969</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-GT2</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td></tr>
</table>

TABLE 41: Hourly Emission Limits for the New Gas Turbines GT3 - GT7 When Turbines Operate During Periods Other Than Startup/Shutdown and Tuning/Testing Mode

Emissions Unit(s)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	VOC (lb/hr)	CO_2e (lb/hr)
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 42: Hourly Emission Limits for Units GT3 - GT7 During Periods When Gas Turbines Operate in Startup/Shutdown (1-hour average)

	NO_x (lb/hr)	CO (lb/hr)
GT3-GT7	31.4	69.2

TABLE 43: 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, 1 hour average	6.0 ppmdv at 15% O_2, 1 hour average	5.4 lbs/hr	5.4 lbs/hr	2 ppmdv at 15% O_2, 1 hour average	1,460 lbs CO_2/MWh gross output, based on a rolling 8,760-operating hour 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 40 through 43:

a. NA (Not Applicable) means that the device does not emit the indicated pollutant.

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.

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

g. CO emissions from Units GT3 through GT7 shall be calculated from CEMS data.

h. PM_{10} and VOC emissions during all operations periods from 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 periods from 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 and the sulfur content of the fuel as determined as specified in this permit.

l. 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.

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

33. OPERATIONAL REQUIREMENTS FOR UNITS GT3 THROUGH GT7:

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

a. The Permittee shall operate and maintain Selective Catalytic Reduction (SCR) 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]

b. 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]

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

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

e. 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.

f. 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.

34. MONITORING AND RECORDKEEPING FACILITY-WIDE:

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 monitor the fuel usage of Units GT1 and GT2. The Permittee shall monitor and record the hours of operation of the emergency generators EG1 and EG2. The Permittee shall monthly calculate and record the emissions from Units GT1 and GT2, GT3 through GT7, EG1 and EG2, and the Cooling Tower and shall monthly compare the calculated emissions to the limits contained in the permit.

35. TOTAL FACILITY EMISSIONS AFTER REVISION:

TABLE 44: Total Allowable Emissions for the Ocotillo Power Plant after the Project

POLLUTANT		Allowable Emission, tons per year						
		GT1-2	**GT3-GT7**	**EG1 EG2**	**Existing Emergency Generator**	**New Diesel and Existing Gasoline Tanks**	**New Cooling Tower**	**TOTAL**
Carbon Monoxide	CO	120.0	239.2	10.8	8.9			378.9
Nitrogen Oxides	NO_x	468.5	125.3		0.3			594.1
Particulate Matter	PM	12.1	54.9	0.6	0.0		5.4	73.0
Particulate Matter	PM_{10}	12.1	54.9	0.6	0.0		1.7	*63.0*
Particulate Matter	$PM_{2.5}$	12.1	54.9	0.6	0.0		1.0	68.6
Sulfur Dioxide	SO_2	0.9	5.9	0.002	0.00			6.8
Vol. Organic Cmpds	VOC	3.1	43.1	0.83	0.01	0.38		47.4
Sulfuric Acid Mist	H_2SO_4	0.1	0.59	0.0	0.0			0.68
Fluorides (as HF)	HF	0.00000	0.0	0.00326	0.0			0.0033
Lead	Pb	0.0007	0.0049	0.0	0.0			0.006
Carbon Dioxide	CO_2	171,253	1,099,504	1,968.9	51.7			1,272,777
Greenhouse Gases	CO_2e	171,430	1,100,640	1,975.6	51.9			1,274,332

Footnote:
The requested plant-wide total allowable PM_{10} emissions are 63.0 tpy.

36. PREVIOUS PUBLIC HEARING AND APPLICATION:

On April 7, 2015 a public hearing was held for APS Ocotillo Modernization Project. Based on the comments received a request for supplemental information was made to the Applicant. Attached below are documents related to previous comments received and the Applicant's responses:

APS response to comments 11-7-2014

APS Response to MCAQD .pdf

MCAQD Response to comments Ocotillo Po

Ocotillo project comments received 1

Ryley Carlock comments MCAQD.pc

Ryley Carlock comments.pdf

Sam Lofland Reconstruction Comm

Sierra Club Comments on Ocotillo

37. 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 attached to this TSD. 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 Treaty 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.

The US Fish and Wildlife Service reviewed the information on the Ocotillo Project. In their April 8, 2014 letter, they stated that "no endangered or threatened species or critical habitat will be affected by this project; nor is this project likely to jeopardize the continued existence of any proposed species or adversely modify any proposed critical habitat. No further ESA review is required for this project at this time." This determination letter is attached below:

Ocotillo Power Plant - Endangered Species.|

38. 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 attached to this TSD. 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.

The full details may be found in the following paper:

Ocotillo Power Plant - Historic Analysis.pdf

SHPO response.pdf

39. ENVIRONMENTAL JUSTICE ANALYSIS:

a. Introduction:

The Applicant prepared an Environmental Justice Analysis as part of its PSD analysis to address any potential issues that may arise. EPA Region 9 has previously prepared an Environmental Justice (EJ) analysis for the Pio Pico Energy Center PSD permit in June 2012, and the Applicant based their Ocotillo EJ analysis on the EPA analysis. The EPA described the requirements for an EJ analysis as follows:

> *Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations," states in relevant part that "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." Federal agencies are required to implement*

this order consistent with, and to the extent permitted by, existing law. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Clean Air Act (CAA) Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices and states acting under delegations of Federal authority. EPA Regional Offices or their delegates in the states have for several years incorporated environmental justice considerations into their review of applications for PSD permits.

For purposes of an EJ analysis, EAB has recognized that compliance with the applicable National Ambient Air Quality Standards (NAAQS) is indicative of achieving a level of public health protection that demonstrates that issuance of a PSD permit will not have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations. This is because the NAAQS are health-based standards, designed to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics.

Since EPA has previously determined that compliance with the applicable NAAQS is sufficient to satisfy the Executive Order as to the pollutants regulated under the PSD program, it can be concluded that the Project will not result in disproportionately high and adverse human health or environmental effects on minority populations and low-income populations. Additional information on air quality in the Project Area, demographics, and public participation/outreach activities is presented in the following sections.

b. Analysis:

In its analysis the Applicant used an EPA developed 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 determined during the Census Bureau's American Community Survey 2008-2012. EJSCREEN has been used to identify potential EJ communities near the Ocotillo Power Plant.

The Applicant presented a EJSCREEN Demographic Index map of the area within approximately 10 miles of the Ocotillo plant. EJSCREEN lists the Demographic Index by reporting the value as a percentile. A percentile in EJSCREEN tells us roughly what percent of the US population lives in a block group that has a lower value of the Demographic Index (in other words, as the percentile value increases, so does the percentage of low-income and minority populations in that census block). (The map is shown in the EJ attachment below)

The geographical distribution of Project's air quality impacts for the two criteria pollutants that trigger PSD review, CO and $PM_{2.5}$, were plotted on a base map of the potential EJ communities near the Ocotillo Power Plant. The EJSCREEN Demographic Index base map and plots of the Project air impacts demonstrate that the Project impacts do not disproportionately occur in potential EJ community areas. (The maps are shown in the EJ attachment below). For example, the distribution of the highest impacts is not disproportionately located at color coded census blocks but also occurs throughout non-color coded census blocks. The same is true for the Project 1-hr CO impact distributions. Again, it must be noted that because ALL impacts are in compliance with the NAAQS, it can be concluded that the Project will not result in disproportionately high and adverse human health or environmental effects on minority populations and low-income populations.

Table 45: Results of NAAQS Air Quality Analysis (ug/m^3)

Pollutant	Averaging Interval	Cumulative Impact	Background	Total	NAAQS	% of NAAQS
CO	8-hour	1231	1832	3063	10,000	31%
	1-hour	1733	2519	4252	40,000	11%
NO_2	Annual	0.7	37	38	100	38%
	1-hour	30.4	115	145	188	77%
SO_2	Annual	0.06	3	3	80	4%
	24-hour	0.16	21	21	365	6%
	3-hour	0.4	21	21	1,300	2%
	1-hour	0.2	21	21	196	11%
$PM_{2.5}$	24-hour	0.9	18	18.9	35	54%
	Annual	0.3	8.9	9.2	15	61%
Pollutant	Averaging Interval	Cumulative Impact	Background	Total	NAAQS	% of NAAQS

c. Public Participation/Outreach Activities:

The Applicant has developed a web page to present information, news updates, Frequency Asked Questions, a video presentation, a blog, and the ability to send comments on the Ocotillo Modernization Project to all interested parties (http://www.azenergyfuture.com/ocotillo/). In addition, the Applicant has advertised for the Project's open house (which was conducted in April 2014) in four different publications, including the Spanish newspaper Prensa Hispana, as well as the Arizona Republic, the East Valley Tribune and the ASU State Press, where the public was made aware of the project and the above website. The advertisements for the project's CEC Line Siting Hearing (conducted in August 2014) were placed in the Arizona Republic and the East Valley Tribune.

Maricopa County is undertaking a number of actions to provide public participation opportunities to the community for its proposed PSD permit decision for the Project. The notice on the proposed permit and any public hearing is provided to the public through a wide variety of methods, including posting on the Maricopa County Air Quality Division Permit Reports website, and publication in the Record Reporter, Business Gazette, and Arizona Republic newspapers. In light of the Spanish-speaking population in the area, Maricopa County will provide sign language and/or Spanish interpreter upon request with 72 hours notice during any public hearing on the proposed permit. Additional reasonable accommodations will be made available to the extent possible within the time frame of the request. The permit application, proposed Technical Support Documentation, and proposed permit can also be reviewed online at the Maricopa County Air Quality Division website.

d. Conclusion:

The County has found the Applicant's EJ analysis to be sufficient to demonstrate compliance with the Executive Order for EJ. For purposes of an EJ analysis, EPA has recognized that compliance with the applicable NAAQS is indicative of achieving a level of public health protection that demonstrates that issuance of a PSD permit will not have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations. Because the Ocotillo Modernization Project air quality analysis has shown that the Project complies with the NAAQS for the pollutants that trigger PSD review, as well as other pollutants, the EJ 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.

The detailed Applicant's EJ Analysis is attached below:

APS Ocotillo Project -
Appendix I - EJ Analy

40. CONCLUSION AND PROPOSED ACTION:

Based on the information supplied by the Applicant, and on the analyses conducted by the MCAQD, the MCAQD has concluded that the requested permit revision is consistent with Federal, State, and County regulations and rules and will not cause or contribute to a violation of any federal ambient air quality standard, will not cause any Arizona Ambient Air Quality Guidelines to be exceeded, and will not cause additional adverse air quality impacts.

The MCAQD proposes to issue the Permit Revision, V95007 – 2.1.0.0, subject to the proposed permit conditions.

Appendix A: Control Technology Review

APS Control
Technology Analysis.

aps

October 29, 2015

RECEIVED
OCT 29 2015
MARICOPA COUNTY
AIR QUALITY DEPARTMENT

Hand Delivered

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

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

Mr. McNeely,

These documents are being submitted as supplemental documentation to the amended permit application submitted to Maricopa County Air Quality Department on September 29, 2015.

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

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

Sincerely,

Dennis Irvin
Plant Manager
Ocotillo Power Plant
Arizona Public Service Company

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

Ocotillo Modernization Project

Arizona Public Service

Appendix F: Air Quality Analysis

Modeling Protocol and Report

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

October 2015

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1.0 Introduction and Project Background

The Ocotillo Power Plant is located at 1500 East University Drive, Tempe Arizona, 85281, in Maricopa County. The plant latitude is 33.425 and longitude is 111.909 at a base elevation of 1,175 feet above mean sea level (AMSL). A project vicinity map is shown as Figure 1, and Figure 2 presents an aerial image of the existing plant.

The Ocotillo Plant has been in operation since 1960. The existing facility 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, a hybrid cooling tower system, two emergency diesel-fired 2.5 MW generators, and support equipment at the Ocotillo Power Plant (the Project). As part of this 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.

Based on the regulatory analysis of Maricopa County Rules contained in the permit application for this Project, it has been shown that:

- The Ocotillo plant is located in a nonattainment area for ozone and PM_{10}.
- Prevention of Significant Deterioration (PSD) permitting requirements apply to the Project for the criteria pollutants CO and $PM_{2.5}$.
- The Ocotillo Plant is not currently classified as a major source of VOC emissions under the non-attainment rules. After completion of the Project, the Plant will no longer be classified as a major source of PM_{10} emissions under the non-attainment rules. Additionally, the NOx net emission increase for the Project is below 40 tpy. Therefore, the Project does not trigger NOx, PM_{10}, or ozone nonattainment permitting requirements.

This modeling protocol presents the procedures that were used for the Project air quality impact analyses that are required under Maricopa's PSD rules, as well as additional supplemental analyses. It follows the general format recommended by the Arizona Department of Environmental Quality (ADEQ) in their *Air Dispersion Modeling Guidelines for Arizona Air Quality Permits*, September 23, 2013.

Figure 1 - Location of the Ocotillo Power Plant

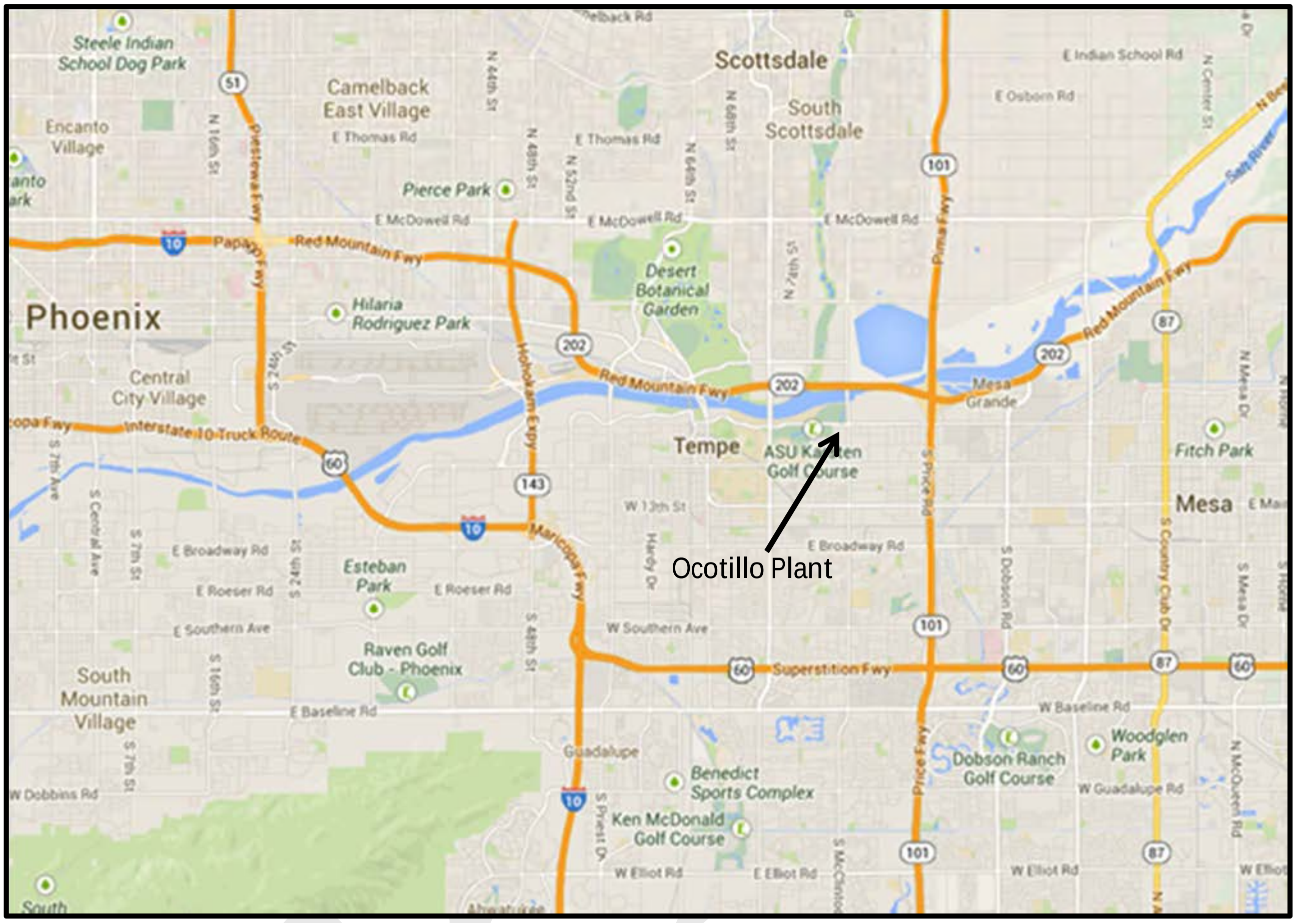


Figure 2 - Aerial Image of Ocotillo Power Plant

1.1 Project Description

APS is planning to install five (5) new natural gas-fired GE Model LMS100 simple cycle GTs, a hybrid cooling tower system, two emergency diesel-fired 2.5 MW generators, and support equipment at the Ocotillo Power Plant. As part of this 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.

The General Electric Model LMS100 simple cycle gas combustion turbine generator (GT) utilizes an aero derivative gas turbine coupled to an electric generator to produce electric energy. 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 LMS100 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 to improve the overall gas turbine thermal efficiency. The turbine exhaust gases will then pass through two post combustion air quality control systems, 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.

A closed-loop cooling system will provide water cooling for the intercooler at each LMS100 GT. The water flow requirements for all five 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 63,500 gpm to provide the cooling necessary for maximum performance and efficiency of the GTs. The mechanical induced-draft wet 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.

The Ocotillo Modernization Project will also include two 2.5 MW emergency generators powered by diesel engines. Because these new generators will be used as emergency diesel generators, APS is proposing operational limits for each generator of no more than 100 hours in any 12 consecutive month period.

1.2 Site Description

The Phoenix metropolitan area is located in the northern reaches of the Sonoran Desert, and is known as the "Valley of the Sun". Scattered, low mountain ranges surround the valley: the McDowell Mountains to the northeast, the White Tank Mountains to the west, the Superstition Mountains to the east, and the Sierra Estrella to the southwest. Other than the mountains in and around the city, the topography of Phoenix is generally flat. The Salt River runs westward through the city of Phoenix, and the riverbed is often dry.

The Ocotillo Power Plant is located at 1500 East University Drive, Tempe Arizona, 85281, in Maricopa County, roughly in the central portion of the Phoenix metropolitan area and south of the Salt River. The plant latitude is 33.425 and longitude is 111.909 at a base elevation of 1,175 feet AMSL.

1.3 Regional Climatology

Most of the following discussion is taken from a climate summary compiled by the National Weather Service Forecast Office in Phoenix, Arizona found at the following internet link: http://www.public.asu.edu/~aunjs/ClimateofPhoenix/phxwx.htm .

The Phoenix climate is of a desert type with low annual rainfall and low relative humidity. Daytime temperatures are high throughout the summer months. The winters are mild. Most deserts undergo drastic fluctuations between day and nighttime temperatures, but not the Phoenix metropolitan area due to the urban heat island effect. As the city has expanded, average summer low temps have been rising steadily. The daily heat of the sun is stored in pavement, sidewalks and buildings, and is radiated back out at night. During the summer, overnight lows greater than 80 °F are commonplace.

There are two separate rainfall seasons. The first occurs during the winter months from November through March when the area is subjected to occasional storms from the Pacific Ocean. While this is classified as a rainfall season, there can be periods of a month or more in this or any other season when practically no precipitation occurs. Snowfall occurs very rarely in the Salt River Valley, while light snows occasionally fall in the higher mountains surrounding the valley. The second rainfall period occurs during July and August when Arizona is subjected to widespread thunderstorm activity whose moisture supply originates in the Gulf of Mexico, in the Pacific Ocean off the west coast of Mexico and in the Gulf of California. The spring and fall months are generally dry, although precipitation in substantial amounts has fallen occasionally during every month of the year.

The valley floor, in general, is rather free of strong wind. During the spring months southwest and west winds predominate and are associated with the passage of low-pressure troughs. During the thunderstorm season in July and August, there are often local, strong, gusty winds with considerable blowing dust. These winds generally come from a northeasterly to southeasterly direction. Throughout the year there are periods, often several days in length, in which winds remain under 10 miles per hour.

Sunshine in Phoenix area averages 86 percent of possible, ranging from a minimum monthly average of around 78 percent in January and December to a maximum of 94 percent in June. During the winter, skies are sometimes cloudy, but sunny skies predominate and the temperatures are mild. During the spring, skies are also predominately sunny with warm temperatures during the day and mild pleasant evenings. Beginning with June, daytime weather is hot. During July and August, there is an increase in humidity, and there is often considerable afternoon and evening cloudiness associated with cumulus clouds building up over the nearby mountains. Summer thunder-showers seldom occur in the valley before evening.

The autumn season, beginning during the latter part of September, is characterized by sudden changes in temperature. The change from the heat of summer to the mild winter temperatures usually occurs during October. The normal temperature change from the beginning to the end of this month is the greatest of any of the twelve months in central Arizona. By November, the mild winter season is definitely established in the Salt River Valley region.

2.0 Regulatory Status

The Ocotillo Power Plant is located in the City of Tempe, Maricopa County, Arizona. The air permitting authority is the Maricopa County Air Quality Department (MCAQD).

2.1 Source Designation

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, therefore the major source emission thresholds under the PSD program are 100 tons per year of any criteria pollutant (other than GHG emissions) and 100,000 tons per year of GHG emissions. 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 criteria pollutant and 100,000 tons per year of GHG emissions. However, because the Ocotillo Power Plant NO_X and GHG potential emissions both before and after the Project are greater than the major source thresholds, the facility will continue to be classified as a major source with respect to the PSD rules.

Based on the total potential emissions for the proposed new emission units, the Project will not result in a significant emissions increase for SO_2, sulfuric acid mist, and fluorides and PSD review is not triggered for those pollutants. Additionally, based on the proposed permanent shutdown and retirement of the Ocotillo Steamer Units 1 and 2, the Project net emission increase for NO_X is below the significant emission rate and PSD review is not triggered for that pollutant. Only the net emission increases for CO, PM, $PM_{2.5}$, and GHG are above the significant emission rates, and PSD review is only triggered for these pollutants. In addition, 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 review for PM_{10}, nor VOC and NO_X as ozone precursors.

Therefore, a PSD air quality impact analysis is required for the two criteria pollutants that trigger PSD review, CO and $PM_{2.5}$. The analysis included the following components:

4 An analysis of existing background monitoring concentrations relative to the NAAQS to confirm that significant impact levels (SILs) can be used in the analysis;

4 Dispersion modeling to determine whether ambient impacts caused by the Project would exceed modeling SILs;

4 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 and Arizona Ambient Air Quality Standards (NAAQS/AAAQS);

4 An assessment of the proposed Project's impacts to the $PM_{2.5}$ PSD increments;

4 An assessment of the proposed Project's impacts to soils, vegetation, and visibility;

4 An assessment of regional population growth and associated emissions that may be caused by the proposed Project; and

4 An assessment of the proposed Project's potential to affect increments, visibility, or other air quality related values (AQRVs) in Class I areas.

Standard PSD air quality analysis requirements do not necessitate an analysis for criteria pollutants that do not trigger PSD review. However, MCAQD has requested that APS perform facility-wide NAAQS analyses for the criteria pollutants NO_2 and SO_2 (the SO_2 analyses will also address Maricopa Rule 32F requirements).

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 ADEQ policy. As noted earlier, the Ocotillo plant after the Project will be classified as a minor nonattainment source for PM_{10} and VOC, and the net emission increase for NOx is less than 40 tpy, therefore the Project does not trigger nonattainment NSR permitting requirements for NOx, PM_{10}, and ozone.

2.2 Area Classifications

The Ocotillo Power Plant is located in the City of Tempe, Maricopa County, Arizona. The location of the power plant is currently designated nonattainment for PM_{10} (classification of serious), and for the 1997 and 2008 8-hour ozone standards (classification of marginal). Therefore, emissions of PM_{10}, NO_X, and VOC pollutants are regulated under the NANSR program. The area is designated as a maintenance area for CO and attainment/unclassifiable for all other criteria pollutants, and these pollutants are regulated under the PSD program.

The nearest Class I areas include the Superstition Wilderness area, located approximately 43 km to the east of the Project, and the Mazatzal Wilderness area, located approximately 62 km to the north of the Project area. Tribal lands within 50 km of the project area include the Salt River, Gila River, and Ft. McDowell Indian Reservations.

2.3 Baseline Dates and Area

A PSD increment is the maximum increase in concentration allowed above an established baseline concentration. The baseline concentration represents the actual ambient concentration existing at the baseline date, defined as the time of the first complete PSD permit application in a given area (referred to as the baseline area or air quality control region). There are actually two baseline dates that are defined: major source baseline dates and minor source baseline dates. The major source baseline date identifies the point in time after which major sources affect available increment, while the minor source baseline date identifies the point in time after which actual emission changes from all sources (both major and minor) affect available increment. The amount of PSD increment that has been consumed within an area is determined from the actual emission increases and decreases that have occurred since the applicable baseline date.

The applicable major source baseline dates are as follows:

4 January 6, 1975, for SO_2 and PM_{10};

4 February 8, 1988, for nitrogen dioxide (NO_2); and

4 October 20, 2010, for $PM_{2.5}$.

The trigger dates are the dates after which a minor source baseline can be established for an area. The applicable trigger dates are as follows:

4 August 7, 1977, for SO_2 and PM_{10};

4 February 8, 1988, for NO_2; and

4 October 20, 2011 for $PM_{2.5}$.

The Ocotillo plant is located in the Maricopa Intrastate Air Quality Control Region, which consists of Maricopa County. The minor source baseline dates have been triggered in this baseline area as follows: for SO_2 and PM_{10} the date is March 3, 1980, and for NO_2 the date is January 20, 1993. Based on discussions with MCAQD and ADEQ, and a review of recent permitting information since the $PM_{2.5}$ major source baseline, it has been determined that there have not been any $PM_{2.5}$ emission increases at major sources and that the $PM_{2.5}$ minor source baseline date has not yet been triggered in Maricopa County. The Ocotillo Project PSD permit application will trigger the $PM_{2.5}$ minor source baseline date, therefore the only $PM_{2.5}$ increment consuming emissions in Maricopa County at the time of this permit application are the Ocotillo Project emissions.

3.0 Ambient Data Requirements

Preconstruction and post-construction monitoring requirements are discussed below.

3.1 Preconstruction Air Quality Monitoring

The collection of ambient air quality data for criteria pollutants that trigger PSD review (CO and $PM_{2.5}$ for the proposed Project) is required prior to construction of a new major source unless representative data from an existing monitor are available. This section contains an analysis of the representativeness of nearby existing $PM_{2.5}$ and CO monitoring data for use in lieu of preconstruction monitoring data collection.

EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration*, 1987, discusses three criteria that help determine the representativeness of existing monitoring data for fulfilling the preconstruction monitoring requirement: the quality of the data, the currentness of the data, and the monitor location. The existing monitoring data must meet quality assurance procedures that are required for the operation of PSD and State and Local Air Monitoring Stations (SLAMS) air monitoring stations. The existing data should have been collected in the recent 3-year period preceding the permit application. And with respect to location, the existing monitoring data should be representative of three types of areas: (1) the locations of maximum concentration increase from the proposed source or modification, (2) the locations of the maximum air pollutant concentration from existing sources, and (3) the locations of the maximum impact area (i.e., where the maximum pollutant concentration would hypothetically occur based on the combined effect of the existing sources and the proposed new source).

In 2011, the National Association of Clean Air Agencies (NACAA) published a report from the NACAA $PM_{2.5}$ Modeling Implementation Workshop, titled *$PM_{2.5}$ Modeling Implementation for Projects Subject to National Ambient Air Quality Demonstration Requirements Pursuant to New Source Review*. A discussion from the Representative Background Concentrations Subgroup expands on the factors to be considered in determining whether a monitoring site is representative of the impact area for a proposed source:

4 Proximity to the source(s) modeled. In general, the nearest monitoring site is preferable. A monitoring site that is far from the source(s) modeled may be affected by the secondary formation on $PM_{2.5}$ precursors that are emitted under much different circumstances.

4 Similarity of the surrounding source(s). Sources in the vicinity of the monitor should be similar to those near the source(s) modeled. The background concentration should not be affected by major point sources that would not affect receptors in the vicinity of the source being permitted. But, the concentrations at a monitoring site that is impacted by

suburban or industrial sources might be representative of the background in an area that has similar sources.

4 Conservativeness of the background concentrations. The intent of any analysis is to ensure that it is "conservative" (i.e., ambient concentrations are overestimated). Thus, an effort should be made to select a background monitoring site where the measured concentrations are equal to or greater than those that would be measured were a monitor to be located in the vicinity of the source(s) to be modeled.

The Air Monitoring Division of MCAQD collects accurate and timely ambient air quality monitoring data within Maricopa County. In cooperation with the EPA and other governmental agencies, the Division operates 24 SLAMS air quality sites which measure for a number of criteria pollutants, including $PM_{2.5}$ and CO, and regularly reports on the monitoring station objectives and data results in periodic Network Plans and Network Assessments. These stations are operated in compliance with SLAMS quality assurance procedures. The Division operates three monitoring stations which triangulate the Ocotillo Plant, and two of the stations are in locations that are upwind and downwind of Ocotillo during the predominate easterly and westerly wind flow directions (see Figure 4):

- The Tempe Station (AQS # 04-013-4005), located 2.3 km to the southwest of Ocotillo, which monitors for $PM_{2.5}$ and CO,

- The Mesa station (AQS # 04-013-1003), located 4.9 km to the east of Ocotillo, which monitors for $PM_{2.5}$ and CO, and

- The South Scottsdale station (AQS # 04-013-3003) located 6.1 km to the north of Ocotillo, which monitors for CO.

Table 1 presents the maximum measured CO concentrations and the $PM_{2.5}$ monitoring design concentrations for these stations for 2012-2014, as reported in EPA's AQS data base at http://www.epa.gov/airdata/ad_rep_mon.html .

Table 1 - Representative CO and $PM_{2.5}$ Ambient Monitoring Data

	24-hr $PM_{2.5}$ µg/m3	Annual $PM_{2.5}$ µg/m3	CO-1hr ppm	CO 8-hr ppm
Tempe Station	18	8.9	2.2	1.6
Mesa Station	14	6.6	2.1	1.4
South Scottsdale Station	NA	NA	2.8	1.4

The data from these three stations are very similar, indicating that the background air quality is relatively uniform in the area covered by these stations and surrounding the Ocotillo plant. As will be shown later, the maximum model predicted impacts for both the Project and the existing Ocotillo plant are located near the plant fence line and well within the area triangulated by these stations. Therefore, the existing monitoring data from these stations are representative of all three potential impact locations discussed in the PSD Monitoring Guidelines (i.e., maximum impact from the Project, maximum impact from existing sources, and maximum combined impact location).

Given the close proximity of the Tempe station to the Ocotillo plant, and the fact that the concentrations are higher at this station than the other two (except for 1-hr CO), the monitoring data from the Tempe station has been selected to fulfill the CO and $PM_{2.5}$ PSD preconstruction monitoring requirements.

3.2 Post-Construction Air Quality Monitoring

Post-construction monitoring is required at the discretion of Maricopa County. No post-construction monitoring is proposed for the Project at this time.

3.3 Meteorological Monitoring

Meteorological data from the National Weather Service Phoenix Sky Harbor airport station for the 5-year period 2009 through 2013 was used along with upper air data from Tucson to generate the AERMOD input data. Sky Harbor airport is located approximately 7 km due west of Ocotillo, at a similar elevation (approximately 1175 feet amsl at Ocotillo and 1130 feet amsl at Sky Harbor). The topography at both locations is also similar, being generally flat and influenced by the east-west oriented Salt River. The close proximity and similar topography indicates that meteorological data from Sky Harbor airport is representative of wind flows at the Ocotillo plant. Refer to Section 5.2 for additional details on this meteorological data set, and the AERMET processing used for the AERMOD model.

3.4 Background Concentrations

Typically the impacts of non-nearby background sources are accounted for by using appropriate, monitored air quality data (i.e., a background concentration). EPA's *Guideline on Air Quality Models*, 40 CFR. Part 51, Appendix W (herein referred to as Appendix W) Section 8.2 discusses requirements for background air quality concentrations that are "an essential part of the total air quality concentration to be considered in determining source impacts." Appendix W states that typically "air quality data should be used to establish background concentrations in the vicinity of the source(s) under consideration."

Based on the analysis of representative existing monitoring data for background concentrations in Section 3.1 of this protocol, the MCAQD Air Monitoring Division Tempe monitor data has been selected for background concentrations of CO and $PM_{2.5}$.

Background concentrations of SO_2 and NO_2 are also collected by the MCAQD Air Monitoring Division. The closest station that monitors these pollutants is the Central Phoenix station. In their 2013 Network Plan and data summary report, Maricopa reported that the 3-year monitoring design concentrations at this station were 61 ppb for the 1-hr NO_2 background, 19.7 ppb for the NO_2 annual average, 8 ppb for the 1-hr SO_2 background, and 1.2 ppb for the SO_2 annual average. These background concentrations were used for the facility-wide NAAQS analyses (the conservative assumption was made to use the 1-hr SO_2 background concentration for the 3-hr and 24-hr SO_2 background values).

4.0 Project Emission Sources

APS is planning to install five (5) new natural gas-fired GE Model LMS100 simple cycle GTs, a hybrid cooling tower system, two emergency diesel-fired 3 MW generators, and support equipment at the Ocotillo Power Plant. As part of this Project, APS plans to retire the two existing steam electric generating units 1 and 2 and associated cooling towers before commencing commercial operation of the proposed new GTs.

The General Electric Model LMS100 simple cycle combustion turbine (CT) generator utilizes an aero derivative gas turbine coupled to an electric generator to produce electric energy. 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 LMS100 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 to improve the overall gas turbine thermal efficiency. The turbine exhaust gases will then pass through two post combustion air quality control systems, 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. Each turbine will exhaust through a seperate stack.

A closed-loop cooling system will provide water cooling for the intercooler at each LMS100 GT. The water flow requirements for all five 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 63,500 gpm to provide the cooling necessary for maximum performance and efficiency of the GTs. The mechanical induced-draft wet 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.

The Ocotillo Modernization Project will also include two 2.5 MW emergency generators powered by diesel engines. Because these new generators will be used as emergency diesel generators, APS is proposing operational limits for each generator of no more than 100 hours in any 12 month period.

Table 2 presents the proposed allowable emissions for the Project emission units. Refer to the Ocotillo Modernization Project Permit Application Section 2 and 3 for additional details on the Project design and equipment.

Table 2 - Proposed Allowable Emissions for Project Emission Units

POLLUTANT		Requested Allowable Emissions, tons per year			
		CT3-CT7	Cooling Tower	Emergency Generators	TOTAL PROJECT
Carbon Monoxide	CO	239.2	0	10.8	249.9
Nitrogen Oxides	NO_X	134.6	0	19.7	125.3
Particulate Matter	PM	54.9	5.6	0.6	60.9
Particulate Matter	PM_{10}	54.9	1.8	0.6	57.2
Particulate Matter	$PM_{2.5}$	54.9	1.1	0.6	56.5
Sulfur Dioxide	SO_2	5.9	0	0.02	5.9

Note that the requested allowable emissions are the same as the potential emissions for all pollutants except NOx emissions. For NOx emissions, APS has requested an enforceable emission cap of 125.3 tpy across all Project emission units.

5.0 Class II Area Analyses

5.1 Scope and Model Selection

Based on the Project net emission increases for criteria pollutants, PSD air quality analysis requirements are triggered only for CO and $PM_{2.5}$. Therefore, the Class II modeling analysis focused on these pollutants. APS also conducted facility-wide NAAQS analyses for the criteria pollutants NO_2 and SO_2.

EPA guidance for performing air quality analyses is described in Chapter C of EPA's *New Source Review Workshop Manual*, Draft - October 1990, in 40 CFR Part 51 Appendix W, in EPA's *AERMOD Users Guide* and related addendums, and in EPA's *AERMOD Implementation Guide*, last updated March 19, 2009. In addition, EPA has developed updated $PM_{2.5}$ analysis guidance and specific 1-hr NO_2 and SO_2 NAAQS modeling analysis guidance. All procedures used for the Ocotillo air quality impact analyses are consistent with this guidance.

Air modeling analyses are typically conducted in two steps: a "project-only" significant impact analysis, and if required a cumulative impact or "full" analysis. The significant impact analysis first estimates ambient impacts resulting from emissions from only the proposed Project, and when the maximum ambient concentrations of a pollutant are below the Significant Impact Level ("SIL"), the emissions from the proposed source are not expected to have a significant impact on ambient air concentrations and further air quality analysis is typically not required for that pollutant and averaging interval. The use of the SILs is further discussed in Section 5.7 of this protocol.

The AERMOD model (version 15181) was used for the air quality analyses, with the regulatory default option set. AERMOD is a steady-state plume dispersion model that simulates transport and dispersion from multiple point, area, or volume sources based on an up-to-date characterization of the atmospheric boundary layer. AERMOD uses Gaussian distributions in the vertical and horizontal for stable conditions, and in the horizontal for convective conditions; the vertical distribution for convective conditions is based on a bi-Gaussian probability density function of the vertical velocity. For elevated terrain AERMOD incorporates the concept of the critical dividing streamline height, in which flow below this height remains horizontal, and flow above this height rises up and over terrain. AERMOD also uses the advanced PRIME algorithm to account for building wake effects.

5.2 Meteorological Data and AERMET Processing

Meteorological data from the Phoenix Sky Harbor airport for the 5-year period 2009 through 2013 was used along with upper air data from Tucson to generate the AERMOD input data. AERMET version 15181 was used to perform Stage 1 processing, along with Stage 2 merging of the data sets. The Sky Harbor airport data was acquired in both the Integrated Surface Hourly Data (ISHD) data format, as well the National Climactic Data Center two-minute averaged wind speed and direction ASOS format. EPA's AERMINUTE program was used to process the minute data. A wind speed threshold of 0.5 m/s was used in the AERMET data processing. The Tucson upper air data was acquired from the NOAA ESRL Radiosonde web page. During the stage 1 processing, it was discovered that numerous morning soundings had missing surface level data for the 2009 through 2011 data years. After discussions with the Arizona Department of Environmental Quality (ADEQ) air modeler, it was confirmed that ADEQ also has noted the missing surface records, and they have processed the original sounding data to insert the missing surface records in the upper air data. Therefore, the ADEQ processed Tucson upper air data for 2009 through 2011 was used for the stage 1 AERMET processing.

AERSURFACE version 13016 was run with U.S. Geological Survey (USGS) National Land Cover Data (NLCD92) to calculate surface characteristics, including activation of the “airport location” and “no continuous snow cover” options. The annual average precipitation at Sky Harbor airport for the period 1950-2015 is 7.43” as reported by the National Weather Service, while the average annual precipitation for the AERMET 5 year period 2009-2013 was 5.95”. Therefore, the “dry moisture” option was set in AERMET. Two sectors were defined for the observed land use patterns, as shown in Figure 3. Stage 3 final AERMET processing was then performed.

The missing data percentages for the final meteorological data set (as reported by AERMOD) are as follows: 0.8% in 2009, 1.5% in 2010, 0.8% in 2011, 3.7% in 2012, 2.1% in 2013, and an average missing data percentage of 1.8%. Figure 4 presents the wind rose for this 5 year meteorological data set. The predominate wind direction patterns are strongly influenced by the east-west oriented Salt River valley topography.

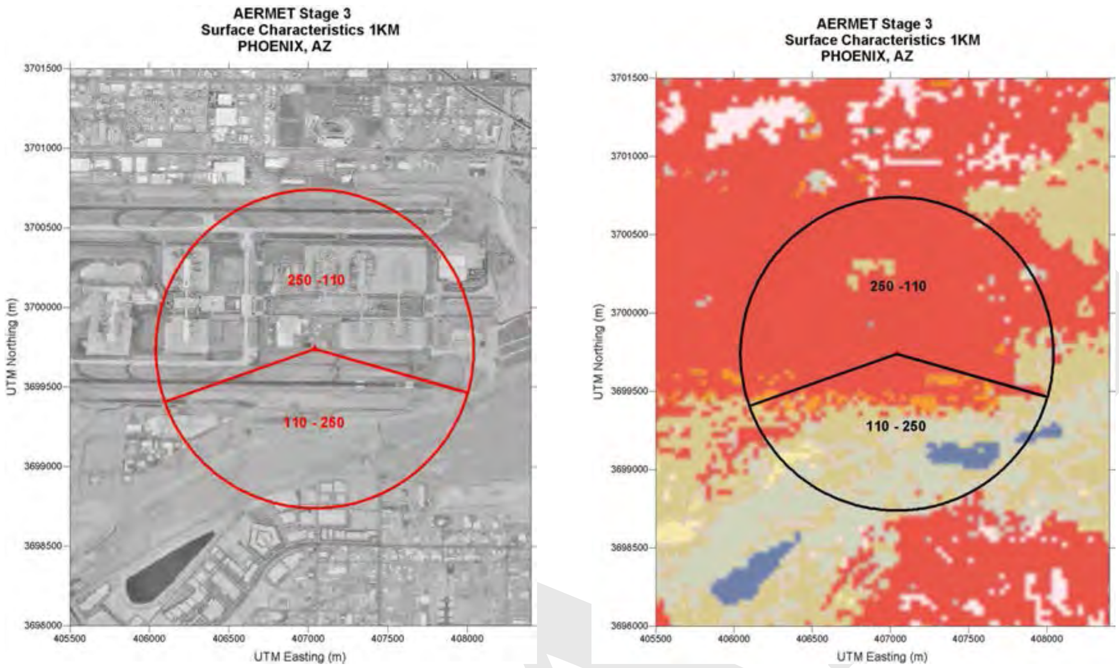
5.3 AERMOD Receptors

A receptor grid, or network, defines the locations of predicted air concentrations that are used to assess compliance with the relevant standards or guidelines. All coordinates used in the modeling are referenced to North American Datum 1983 (NAD83), Zone 12.

The latest version of the AERMAP program was used to develop the model receptor grids. USGS National Elevation Data (NED) at 1/3 Arc Second resolution was used as the elevation data source for the AERMAP processing. The main receptor network used for the air modeling consisted of 8,638 receptors based on "discrete" rectangular grids centered on the Project. These rectangular grids were supplemented by 100 meter spaced grids at Camelback Mountain, a prominent terrain feature located to the north-northwest of the Ocotillo plant. The main grid consists of the following sub-grids, and Figures 5 and 6 present views of the main and close-in receptor grids:

- 25-meter spaced grid on the facility boundary,
- 50-meter spaced grid to a distance of 150 meters in all directions,
- 100-meter spaced grid from 150 meters out to a distance of 1 km in all directions,
- 250-meter spaced grid from 1 km out to a distance of 2.5 km in all directions,
- 500-meter spaced grid from 2.5 km out to a distance of 5 km in all directions,
- 1000-meter spaced grid from 5 km out to a distance of 15 km in all directions.

Figure 3 - AERSURFACE Sectors for Land Use Data Processing



Note: The plot on the right is of the USGS Land Use types.

Figure 4 - Wind Rose for Phoenix Airport Meteorological Data

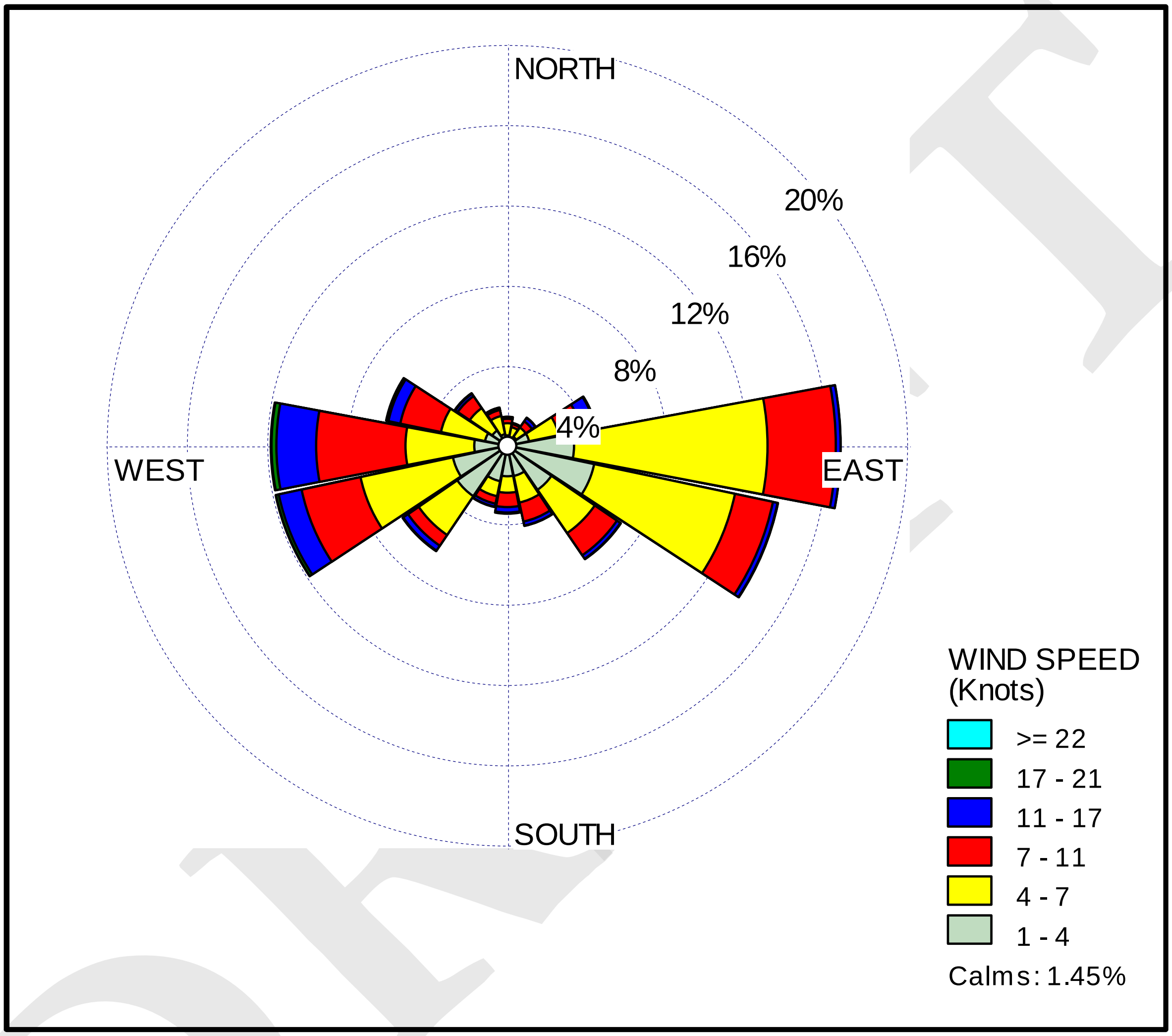


Figure 5 - Main AERMAP Receptor Grid

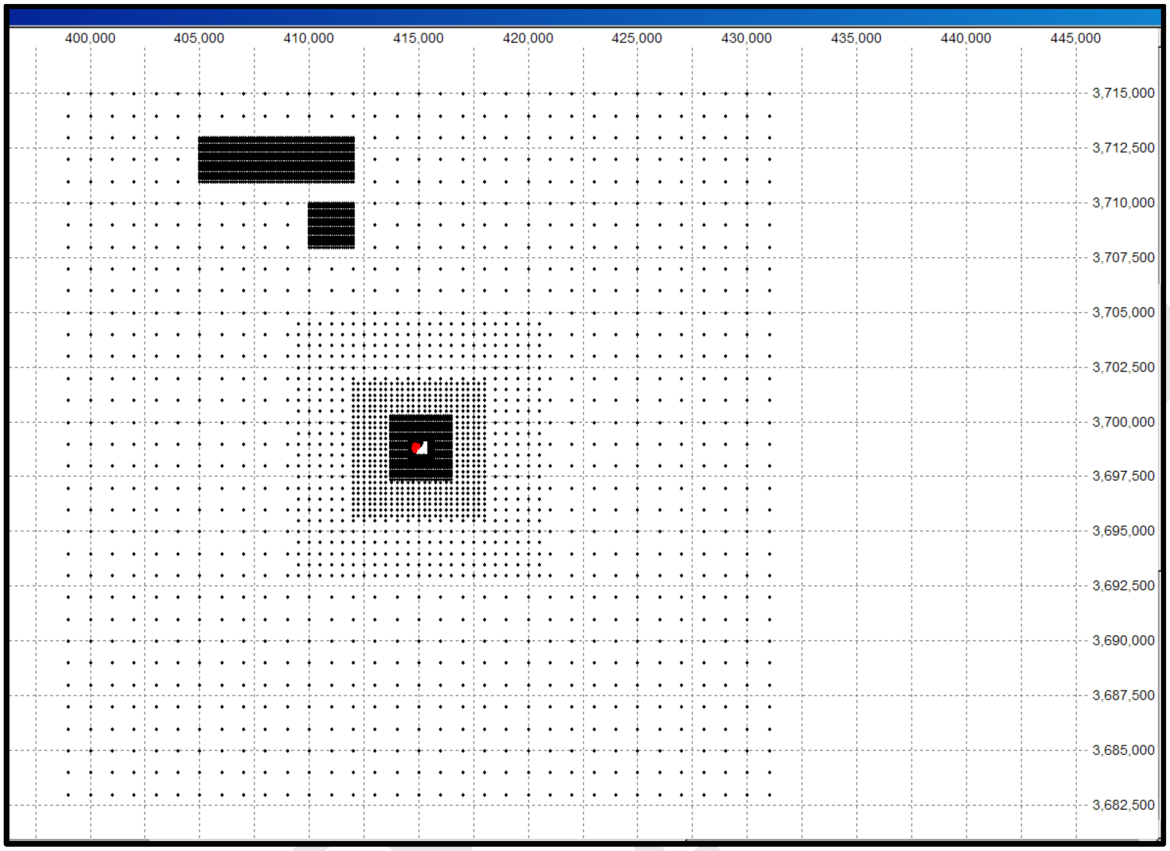
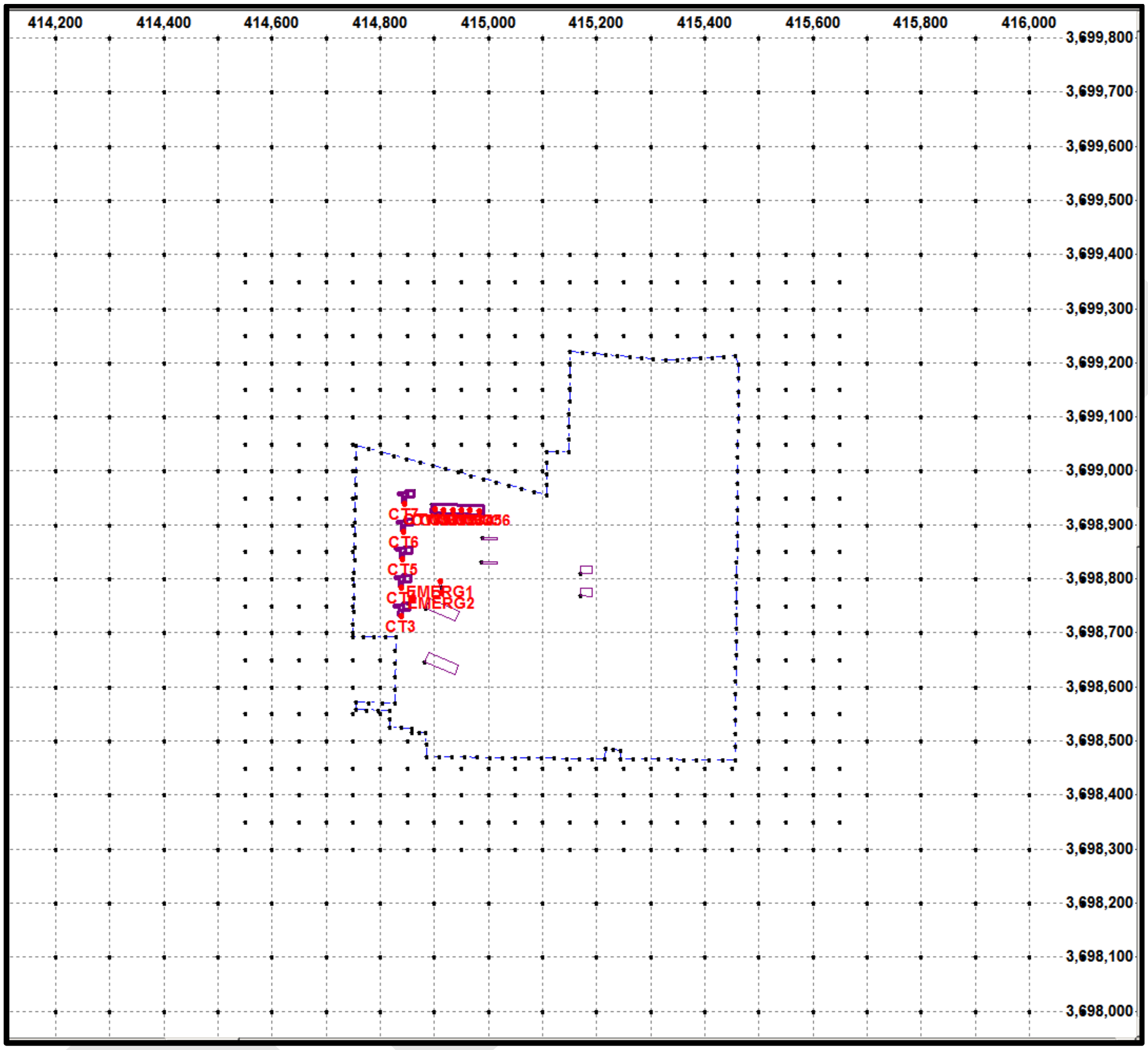


Figure 6 - Close-in AERMAP Receptor Grid



5.4 Urban versus Rural Dispersion Coefficients

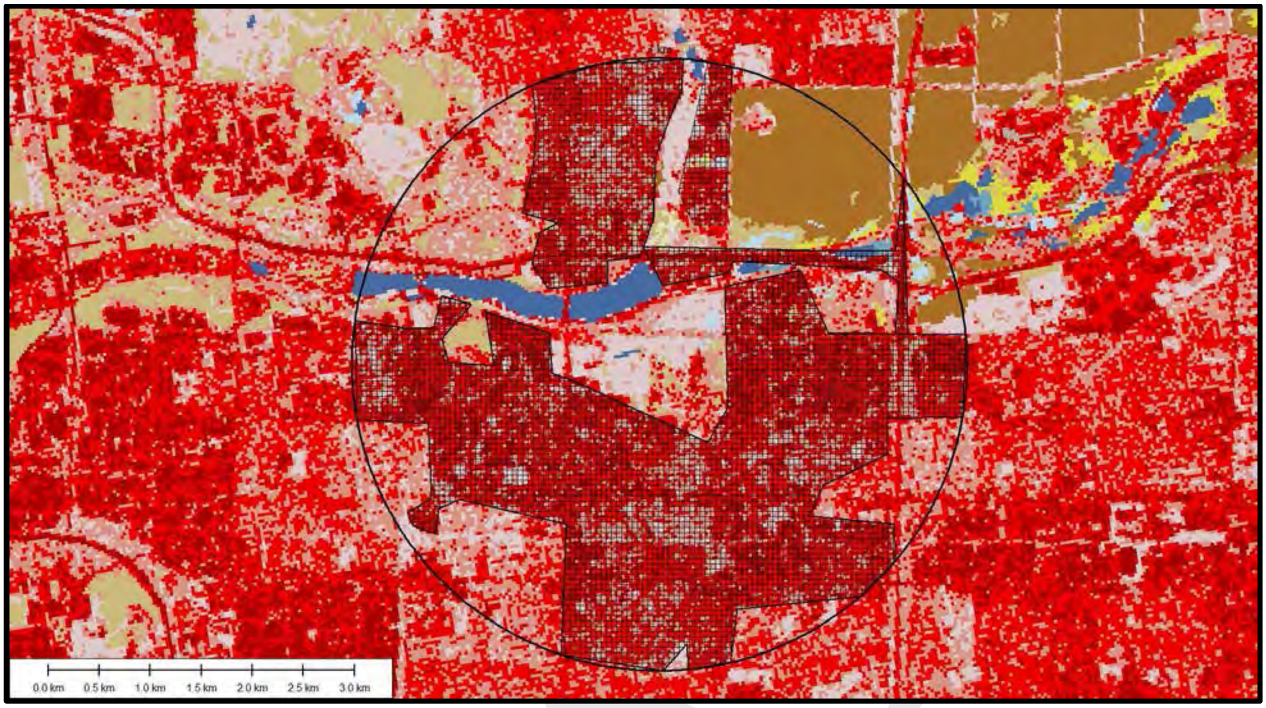
The AERMOD model allows the user to incorporate the effects of increased surface heating from an urban area on pollutant dispersion under stable atmospheric conditions. The selection of either rural or urban dispersion coefficients should follow the procedures listed in Appendix W Section 7.2.3. The preferred Land Use Procedure classifies the land use within a 3km radius circle about the source using the meteorological land use typing scheme. If land use types I1, I2, C1, R2, and R3 account for 50 percent or more of the circle area, urban dispersion coefficients should be used. Sources located in areas defined as rural should be modeled using the rural dispersion parameters.

The land use typing scheme was used to determine the proper land use classification and AERMOD dispersion option for the Ocotillo plant. The USGS NLCD for 2011 for a 3 km radius centered on the plant (see Figure 7) was reviewed. In accordance with Appendix W, an urban dispersion classification is to be used if the Auer land use types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (compact residential) and R3 (compact residential) account for 50% or more of the area within the 3 km radius around the site. The Auer land use classifications I1, I2, C1, R2 and R3 are no longer used by USGS, and these Auer classes correspond to the new NLCD 2011 land cover classes 23 (developed, medium intensity) and 24 (developed, high intensity), as shown in Table 3. Land cover classes 23 and 24 are shown as bright red and dark red areas in Figure 7.

Table 3 - Land Cover Class Cross-Referencing

<table>
<tr><td colspan="3">Auer – “Urban” Classes</td><td colspan="3">NLCD 2011 Equivalent Classes</td></tr>
<tr><td>Type</td><td>Use</td><td>Vegetation</td><td>Pervious</td><td>Use</td><td>No.</td></tr>
<tr><td>I1</td><td>Heavy Industrial</td><td><5 %</td><td rowspan="3">0-20 %</td><td rowspan="3">Developed,
high intensity</td><td rowspan="3">24</td></tr>
<tr><td>I2</td><td>Light Industrial</td><td><5 %</td></tr>
<tr><td>C1</td><td>Comm.</td><td><15 %</td></tr>
<tr><td>R2</td><td>Compact Residential</td><td><30 %</td><td rowspan="2">20-50 %</td><td rowspan="2">Developed,
medium intensity</td><td rowspan="2">23</td></tr>
<tr><td>R3</td><td>Compact Residential</td><td><35 %</td></tr>
</table>

Figure 7 – NLCD 2011 Land Use Categories near Ocotillo Plant



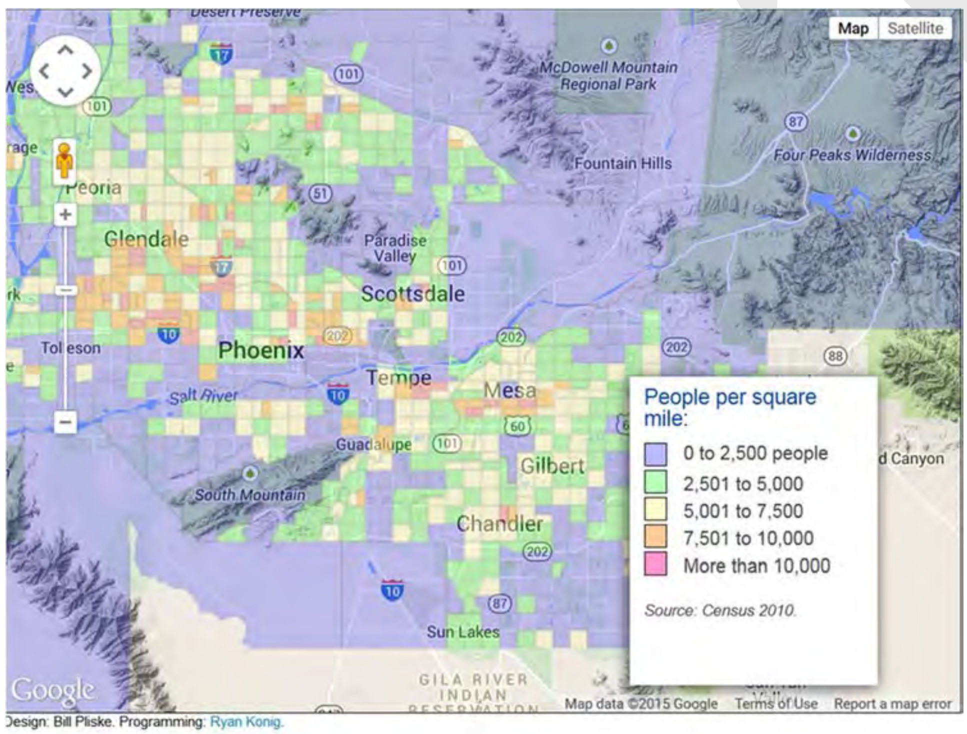
The estimated total area for land cover classes 23 and 24 is shown in Figure 7 as the hatched areas within the 3km circle. The hatched area is 15.5 sq-km in size, and the total area of the 3km radius circle is 28.4 sq-km. To perform a more precise analysis of the land cover data, the NLCD GEOTIFF file was converted to an ASCII XYZ file, and the exact percentage of cells within the 3 km radius of Ocotillo that were equal to land cover classes 23 and 24 were determined. Land cover classes 23 and 24 account for 52.3% of the total area within a 3 km radius around the site, therefore the area is designated as "urban" and the AERMOD URBAN modeling option must be used.

EPA's *AERMOD Implementation Guide*, March 19, 2009, discusses EPA's recommendations for evaluating population data for URBAN mode modeling. For urban areas adjacent to or near other urban areas, or part of urban corridors, the analysis should attempt to identify that portion of the urban area that will contribute to the urban heat island plume affecting the source. This can be evaluated by reviewing the population density variations, urban heat island temperature data, and typical wind flow patterns near the source. EPA does not recommend using population based on the entire MSA for applications within urban corridors, since this may tend to overstate the urban heat island effect. For situations where entire MSAs may not be appropriate, the analysis may determine the extent of the area, including the source of interest, where the population density exceeds 750 people per square kilometer (1,940 people per square mile). The combined population within this identified area may then be used for input to the AERMOD model. It should also be noted that the urban algorithms in AERMOD are dependent on population to the one-fourth power, and are therefore not highly sensitive to variations in population. Population estimates to two significant figures should be sufficiently accurate for application of AERMOD.

The US Census Bureau designates Phoenix as the Phoenix-Mesa-Glendale Metropolitan Statistical Area (MSA), including Maricopa and Pinal counties. As of 2010 the Census Bureau reported that the two-county MSA had a population of 4,192,887, making it the 14th largest MSA in the United

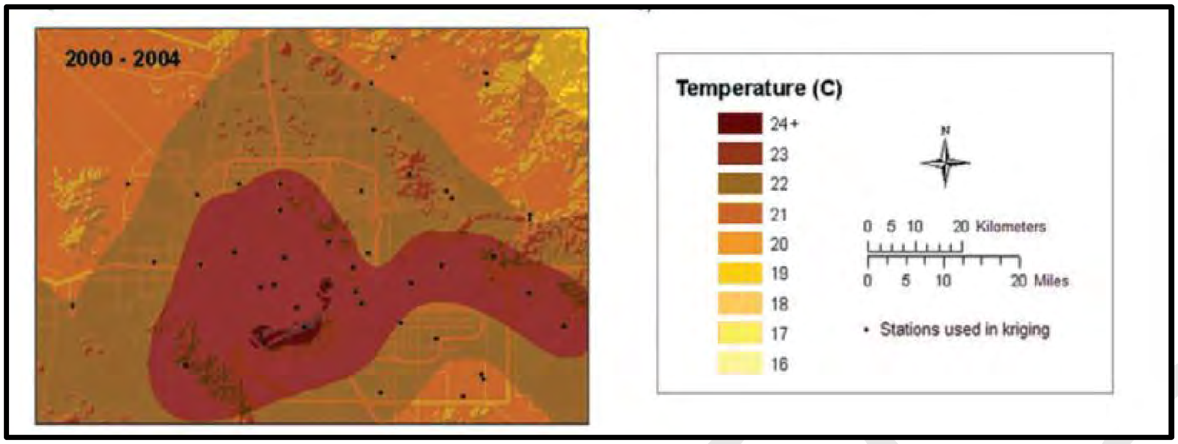
States. The two counties that comprise the Phoenix MSA are relatively large counties, with a rugged desert landscape and significant portions of land that are rural or uninhabited. Figure 8 is a map of the Census 2010 population density throughout the Phoenix area (www.azcentral.com/news/census/), which highlights the mix of census tracts with high and low population densities. All tracts with any color besides purple exceed the EPA "urban threshold" population density of 1,940 people per square mile. Note that the low population density area between Tempe and Phoenix (near the I-10 symbol on the map) includes the Phoenix airport area, which because of significant paved surface areas would still contribute to the urban heat island effect. For reference, the Ocotillo plant is located in Tempe and the predominate wind flows are along the Salt River in the general east/west orientation.

Figure 8 - Phoenix 2010 Population Density



A significant amount of research has been done on urban heat islands in Phoenix, in particular by researchers at Arizona State University (ASU). Figure 9 is a graph from one of these studies of the June nighttime minimum air temperature patterns in the Phoenix metropolitan area, as reported by Dr. Winston Chow of ASU in the journal article *Urban Heat Island Research in Phoenix, Arizona: Theoretical Contributions and Policy Applications*, Winston T. L. Chow, Dean Brennan, and Anthony J. Brazel, 2012, Bull. Amer. Meteor. Soc., 93, 517–530. The increase in night time temperatures is one of the primary characteristics of the urban heat island effect, and Figure 9 helps identify those portions of the Phoenix MSA with the most significant urban heat island effects. The area with the most significant effects includes the cities of Tempe, Mesa, and Phoenix.

Figure 9 - Phoenix Nighttime Air Temperature Patterns



The entire Phoenix MSA population value of 4,300,000 is not appropriate for the AERMOD URBAN population value because of the variations in population density and land use across the Phoenix MSA. Based upon a review of the Phoenix MSA population density and nighttime air temperature heat island patterns in the area, the portions of the Phoenix MSA that will contribute most to the urban heat island effect at Ocotillo would be the cities of Phoenix, Tempe, and Mesa. These three cities also lie along the east-west orientation of the Salt River valley, with the Ocotillo plant located in the central portion of this area. The predominate winds at Ocotillo occur from the Phoenix and Mesa directions, also indicating that these two cities along with Tempe will most strongly influence the urban heat island effect. The population from more distant cities, such as Glendale and Scottsdale, are less likely to influence conditions at Ocotillo. Based on 2010 US Census data found at http://quickfacts.census.gov/qfd/states/04/0455000lk.html, the combined population of Tempe, Mesa, and Phoenix is approximately 2,046,000, and this population value was selected for use in AERMOD URBAN modeling. It should be noted again that EPA has stated that the urban algorithms in AERMOD are dependent on population to the one-fourth power, and are therefore not highly sensitive to variations in population.

5.5 Building Downwash

AERMOD can account for building downwash effects. The stack locations, stack heights, and structure locations and dimensions at the Project were input to EPA's "Building Profile Input Program – PRIME" (BPIP-PRIME) computer program. BPIP-PRIME processes this data in two steps. The first step determines and reports on whether or not a stack meets Good Engineering Practice (GEP) requirements and is subject to wake effects from a structure or structures. The second step calculated the "equivalent building dimensions" if a stack is influenced by structure wake effects in a format that is accepted by AERMOD. Since some stacks at the Project are influenced by wake effects, the BPIP-PRIME output for those stacks were input to the AERMOD model input file.

Because the new GTs may begin operation before the existing steam boiler structures are completely dismantled, two sets of BPIP-PRIME analyses were performed, both with and without the existing steam boiler structures. The calculated building downwash parameters are the same for these two BPIP-PRIME analyses, indicating that the steam boiler existing structures are not the controlling structures for the new emission units and the AERMOD predicted impacts for the new emission units are not affected by these existing structures.

5.6 Modeling of NO_2 Impacts

The Project does not trigger PSD-review for NO_2, however a facility wide NO_2 NAAQS analysis was performed. The Plume Volume Molar Ratio Method (PVMRM) option in AERMOD was used to account for the after stack conversion of emitted NO_X to downwind NO_2. This option requires an ozone data file. Ozone concentrations from the three nearby MCAQD SLAMS monitoring stations described in Section 3.1 were used to compile a conservative background ozone data set. The ozone data include periods of missing data at some stations, because they were operated as seasonal ozone monitors in 2009 and early 2010. Therefore, the AERMOD "MHRDOW" monthly and hour of day varying background ozone option was used. The highest ozone concentration observed at any of these three stations for each hour of the day by month was selected from the 5 year data period from 2009 through 2013. This is a very conservative method of incorporating background ozone concentrations into AERMOD's PVMRM option.

The use of PVMRM also requires use of an in-stack ratio (ISR) for each source. EPA's recommended default ISR of 0.5 was used for all NO_X emission sources. In accordance with EPA's guidance on modeling intermittent sources, the emergency engines were not be included in the 1-hour NO_2 (and 1-hour SO_2) modeling, but were included in all other pollutants and averaging period modeling.

5.7 $PM_{2.5}$ Modeling Procedures

The Project triggers PSD-review for $PM_{2.5}$, and the $PM_{2.5}$ air quality analysis followed the procedures described in EPA's March 2014 *Guidance for $PM_{2.5}$ Permit Modeling*. Because the net emission increases of the $PM_{2.5}$ precursor pollutants SO_2 and NO_X are below the PSD Significant Emission Rates, the $PM_{2.5}$ analysis for the Project was a "Case 2" analysis as described in Section II.4 of the EPA guidance document. Case 2 analyses only require the direct $PM_{2.5}$ emissions to be modeled to determine the Project's $PM_{2.5}$ Primary Impact analysis.

Air modeling analyses are typically conducted in two steps: a "project-only" significant impact analysis, and if required a cumulative impact or "full" analysis. The significant impact analysis first estimates ambient impacts resulting from emissions from only the proposed Project, and when the maximum ambient concentrations of a pollutant are below the Significant Impact Level ("SIL"), the emissions from the proposed source are not expected to have a significant impact on ambient air concentrations and further air quality analysis is typically not required for that pollutant and averaging interval. In the March 2014 "Guidance for $PM_{2.5}$ Permit Modeling", EPA discusses developments regarding the use of $PM_{2.5}$ SILs after the January 22, 2013, the U.S. Court of Appeals for the District of Columbia Circuit decision. EPA does not interpret the court's decision to preclude the use of SILs for $PM_{2.5}$ as part of a demonstration that a source will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS. However, to ensure that PSD permitting decisions meet the requirements of the CAA, permitting authorities that continue using SILs for $PM_{2.5}$ must ensure that they apply the SILs in a manner that is consistent with the court's decision and the EPA's statements from the preamble of the 2010 regulation adopting SILs for $PM_{2.5}$.

EPA believes permitting authorities may continue to apply SILs for $PM_{2.5}$ to support PSD permitting decisions with appropriate safeguards. EPA recommends that the permitting authority must first examine background air quality concentrations to determine whether a substantial portion of the NAAQS has been consumed. For this purpose, the EPA recommends using the preconstruction monitoring data compiled to meet the requirements of Section 51.166(m) or 52.21(m) of the EPA's regulations. If the preconstruction monitoring data are sufficiently representative of the air quality in existence before the increase in emissions from the proposed source and the difference between the $PM_{2.5}$ NAAQS and the measured $PM_{2.5}$ background concentrations in the area is greater than or equal to the selected SIL value, then the EPA believes it would be sufficient in most cases for permitting authorities to conclude that a source with an impact equal to or below that SIL value will not cause or contribute to a violation of the NAAQS and to forego a cumulative modeling analysis for $PM_{2.5}$ with respect to the NAAQS.

Second, EPA recommends that the permitting agency determine if there is sufficient "headroom" within the allowable increment to absorb a source contribution equal to the SIL. Since the $PM_{2.5}$ minor source increment trigger date has only relatively recently been established (i.e., October 20, 2011), for the next several years, a new or modified source being evaluated for $PM_{2.5}$ increments compliance will often be the first source with increment-consuming emissions in the area. Under this situation, a permitting authority may have sufficient reason to conclude that the impacts of the new or modified source may be compared directly to the allowable increments, without the need for a cumulative increment modeling analysis. Such a situation would involve the new or modified source representing the first PSD application in the area after the trigger date, which establishes the minor source baseline date and baseline area, and confirmation that no relevant major source construction has already occurred since the major source baseline date.

Preconstruction and background monitoring data have been identified in Sections 3.1 and 3.4 of this protocol, and the data is summarized along with the NAAQS and SILs in Table 4. This data indicates that for $PM_{2.5}$, as well as all other criteria pollutants and averaging intervals listed in this table, the difference between the NAAQS and existing air quality concentrations is greater than the SILs. Therefore, there is adequate headroom between the existing air quality and the NAAQS to permit the use of the SILs for the NAAQS modeling analyses.

Table 4 – Background Concentrations, NAAQS, and SILs

	NAAQS	Existing Air Quality	Difference between NAAAQS and Existing	SIL
$PM_{2.5}$ 24-hr	35	18	17	1.2
$PM_{2.5}$ Annual	12	8.9	3.1	0.3
CO 1-hr	40,000	2,519	37,481	2,000
CO 8-hr	10,000	1,832	8,168	500
SO_2 1-hr	196	21	175	7.8
SO_2 Annual	80	3.1	76.9	1
NO_2 1-hr	188	115	73	7.5
NO_2 Annual	100	37	63	1

Note: All values are expressed in units of $\mu g/m^3$.

With respect to the $PM_{2.5}$ PSD increments, based on a review of available information it has been determined that the $PM_{2.5}$ minor source increment date has not yet been triggered by a complete PSD permit application in Maricopa County, nor has there been any major source construction since the major source baseline date. The Ocotillo Project PSD permit application will trigger the $PM_{2.5}$ minor source baseline date, and the only $PM_{2.5}$ increment consuming emissions in Maricopa County at the time of this permit application are the Ocotillo Project emissions. Therefore, the $PM_{2.5}$ impacts of the Project may be compared directly to the allowable $PM_{2.5}$ increments.

5.8 Source Characteristics

This section describes how the project emission sources were characterized for modeling. All of the emission sources at Ocotillo were modeled as POINT sources in AERMOD, as there are no fugitive dust sources that would require AREA or VOLUME source treatments.

5.8.1 Source Locations

Figures 10 and 11 present a plot plan and an aerial photo of the layout of the emission sources that are described in Section 4.0. Also included in Figure 10 is the layout of the structures at the facility. Note that the existing oil storage tanks and steam generating unit structures will be removed as part of this Project.

5.8.2 Source Emissions

Chapter 3 of the Ocotillo permit application contains detailed information on the calculation of Project maximum hourly and annual emissions. Emissions from the LMS100 GTs included both normal operation and startup/shutdown emission calculations. The normal emissions for each GT are based on the maximum rated heat input, the proposed BACT emission limits, manufacturer's maximum hourly emission rates, and the fuel use limits. The manufacturer's normal operating emissions and stack data are presented in Appendix A for a wide range of unit operating load and ambient air conditions.

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 equation described in EPA AP-42 Section 13.4. 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 $PM_{2.5}$. Maricopa County has 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 same 0.6 factor was used for the Ocotillo cooling tower calculations.

Figure 10 - Plot Plan of Project

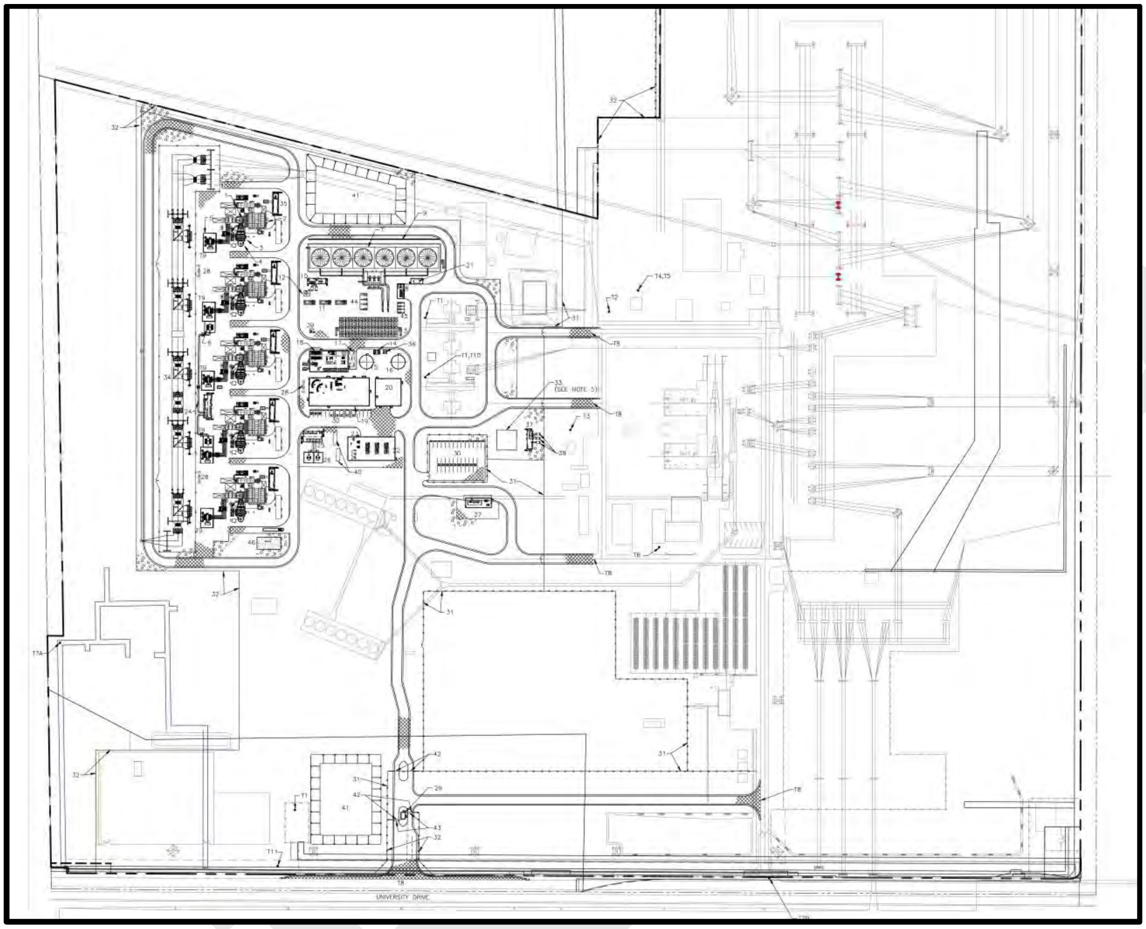
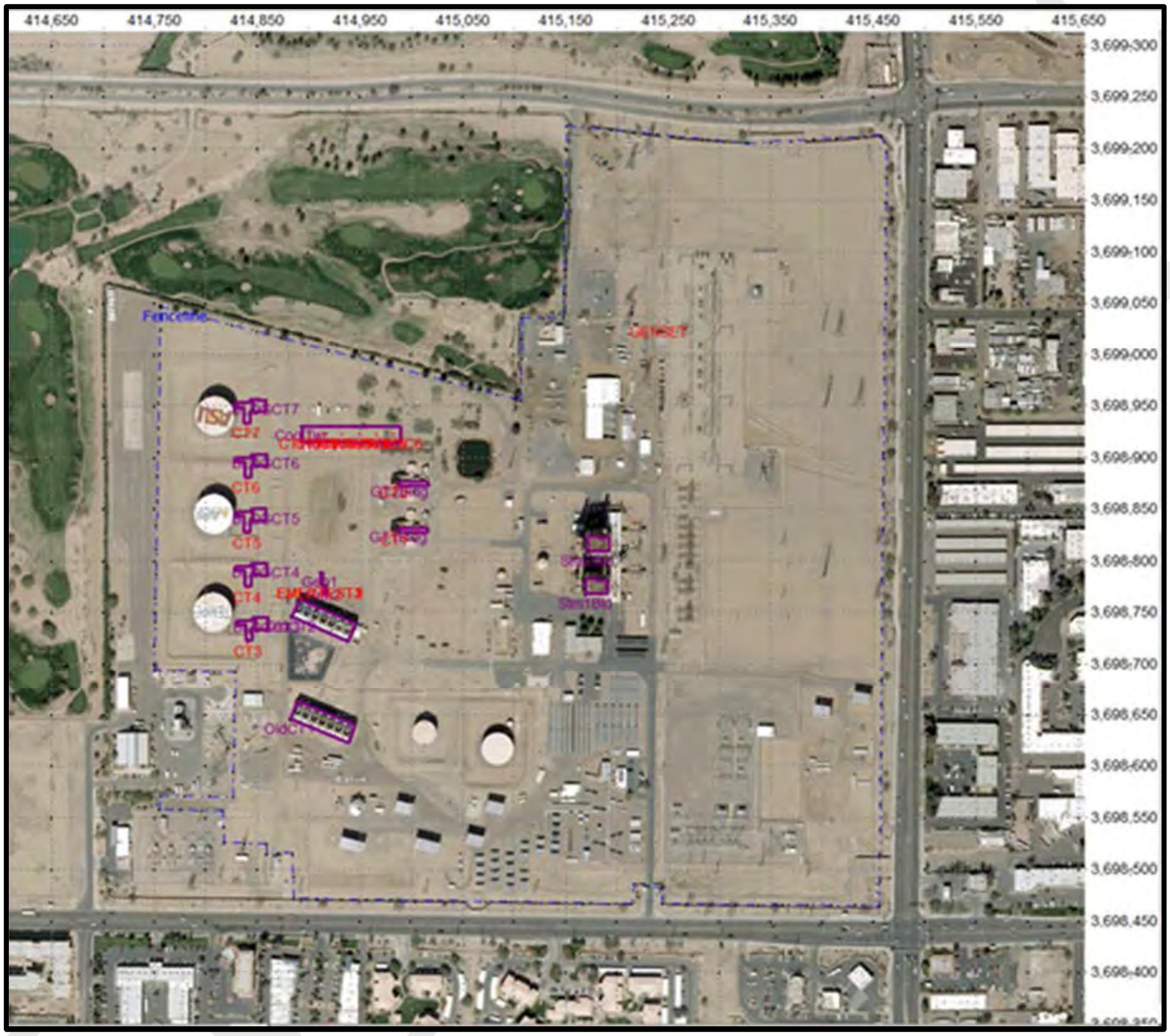


Figure 11 - Modeling Layout of Project Emission Units and Structures

Note: Coordinates are UTM NAD 83 Zone 12. Note that the current oil storage tanks and steam units will be removed.



The emissions from the proposed new emergency generators were based on the Tier 2 New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines found in 40 CFR 60, Subpart IIII. In accordance with EPA's guidance on modeling intermittent sources (EPA 2011), the emergency generators will not be included in the 1-hour SO_2 and NO_2 modeling, but were included in all other analyses. These emergency units are typically tested for one 30 minute test period each month for 11 out of 12 months, and then for an annual 2 hour test during the remaining month. In order to simulate this operating schedule in the modeling analysis, one emergency generator was conservatively modeled as operating between the hours of 8-10am, and 10am-noon, and noon-2pm for everyday of the year using three AERMOD source groups. This represents the testing of the emergency units for up to 2 hours between the times of 8am and 2pm, so long as only one generator is being tested at any given time.

For the Project's $PM_{2.5}$ significant impact and PSD increment analyses, the Projects net emission increase was modeled using positive emissions for all new emission units and negative emissions for the two existing steam boilers that will be retired. The existing steam boiler $PM_{2.5}$ emission rates are based on boiler capacities of 1,210 MMBtu/hr and the AP-42 $PM_{2.5}$ natural gas emission factor of 0.0075 lb/MMBtu listed in Table 1.4-2. The stack parameters used for each of the steam boiler stacks (there are two stacks for each boiler) include a stack height of 178 feet, a stack diameter of 8.58 feet, an exit temperature of 274F, and an exit velocity of 55.6 ft/sec.

5.8.3 Load Screening and Operating Scenarios

The pollutants that may be emitted by the proposed project are subject to air quality standards and PSD increments with various averaging periods. Consequently, the emissions modeled must include the maximum "worst-case" short-term emissions for prediction of short-term maximum concentrations, as well as the annual emissions for prediction of annual average impacts.

Operating load and ambient temperature affect turbine emissions and stack flow rates, and turbine emissions profiles also vary during startup and shutdown. In general, emissions of PM_{10}, $PM_{2.5}$, and SO_2 from gas turbines are highest at full load normal operation, while emissions of NO_X and CO are highest during startup. Addressing this variability in turbine emissions and flows for short-term modeling can therefore become very complex, with large numbers of potential emission and flow scenarios. However, certain conservative and simplifying assumptions can be made which reduce the number of scenarios that need to be modeled.

A load screening analysis was performed for the proposed GTs as recommended by EPA in Appendix W Section 8.1.2. Modeling each of the 24 operating cases presented in Appendix A for the appropriate season (i.e., ambient temperature) that the scenario could occur in would result in a complex analysis with numerous model runs. Therefore, a simplified yet conservative analysis was performed by modeling the "worst-case" minimum stack temperatures and flow rates for 100%, 75%, 50%, and 25% loads from any ambient operating temperature. Using the minimum stack temperature and flow rate is "worst-case" because these conditions result in less plume rise and resulting higher predicted ambient concentrations. For the $PM_{2.5}$ and SO_2 load screening analysis, the normalized emissions for the four load scenarios was set to values of 1.0, 0.79, 0.59, and 0.38 which are based on the relative heat input at these four loads.

For the CO and NO_2 impact analyses, a multi-level load screening analysis was not performed for the GTs because the short-term emission rates during startup operation are significantly higher than during normal operation. Therefore, the maximum startup emission rate was modeled for all 5 GTs for the entire year, using 25% load stack parameters to best match startup flows and temperatures. In effect, the CO and 1-hr NO_2 modeling analyses were based on all 5 GTs being in startup mode continuously for every hour in the year. This is a very conservative assumption. The annual NO_2 impact analysis was based on the annual allowable emission rates, again conservatively modeled at the 25% load stack parameters.

The load screening analysis for the proposed emergency generator IC engines considered operations at 100%, 75%, and 50% loads. Because vendor or source test data are not readily available for partial load operations, the procedures developed by the Alaska Department of Environmental Conservation was used to estimate stack parameters as described in ADEC *Modeling Review Procedures Manual*, October 13, 2006 (note that there is a very large number of IC engines that have been permitted and modeled in Alaska, and ADEC has compiled and reviewed information on a wide variety of engines). The ADEC guidance states that flow rates vary linearly with load, and part load exhaust temperature (in degrees K) can be estimated using a factor of 0.90 for the 75 percent load scenario and by 0.85 for the 50 percent load scenario. The emissions that were modeled for the Ocotillo IC engines are calculated based on relative fuel use, which based on vendor data in the permit application are 78% of full load emissions for 75% operating load, and 56% of full load emissions for 50% operating load.

The cooling towers are not operated at various loads, and were modeled using the normal operating stack parameters and maximum emission rates.

5.7 Load Screening Results

Table 5 summarizes the results of the load screening analysis using the model predicted "highest first high" concentrations averaged across the complete 5 year meteorological data set. Table 4 indicates that the 100% load condition results in the maximum impacts for all averaging intervals for the GTs and the emergency generators. Table 6 presents the stack parameters and emission rates that were used in the modeling analysis.

Table 5 - Load Screening Modeling Results

Emission Unit & Load Level	Annual	1-Hr	3-Hr	8-Hr	24-Hr
GT 100%	0.032	0.88	0.67	0.51	0.18
GT 75%	0.030	0.85	0.62	0.47	0.16
GT 50%	0.027	0.78	0.57	0.41	0.14
GT 25%	0.024	0.66	0.48	0.33	0.12
Emergency Generator 100%	1.90	NA	98.5	83.3	52.0
Emergency Generator 75%	1.88	NA	85.9	76.5	45.4
Emergency Generator 50%	1.76	NA	72.9	62.9	37.0

Note: The values reported are the normalized impacts in units of µg/m3. The emergency generators are not run for 1-hr SO_2 and NO_2 analyses, and therefore load screening for the 1-hr period is not required for those emission units.

Table 6 – Project Emission and Stack Data used in AERMOD Analyses

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Tempera-ture (°F)	Exit Velocity (fps)	Stack Diameter (ft)	CO (lb/hr)	PM25 (lb/hr)
GT3	CT3-LMS100	414841	3698721	1172	85	771	115	13.5	69.2	5.4
GT4	CT4-LMS101	414841	3698774	1172	85	771	115	13.5	69.2	5.4
GT5	CT5-LMS102	414840	3698827	1172	85	771	115	13.5	69.2	5.4
GT6	CT6-LMS103	414840	3698880	1172	85	771	115	13.5	69.2	5.4
GT7	CT7-LMS104	414840	3698932	1172	85	771	115	13.5	69.2	5.4
GTCT C1	CoolTwr Fan 1	414901	3698922	1171	40	87.5	33.4	30	NA	0.039
GTCT C2	CoolTwr Fan 2	414917	3698922	1171	40	87.5	33.4	30	NA	0.039
GTCT C3	CoolTwr Fan 3	414933	3698923	1171	40	87.5	33.4	30	NA	0.039
GTCT C4	CoolTwr Fan 4	414950	3698923	1171	40	87.5	33.4	30	NA	0.039
GTCT C5	CoolTwr Fan 5	414966	3698923	1171	40	87.5	33.4	30	NA	0.039
GTCT C6	CoolTwr Fan 6	414983	3698923	1171	40	87.5	33.4	30	NA	0.039
EMERG	Emergency Generator	414911	3698778	1171	16	794	185	1.5	21.6	1.24

Notes:

The GT3-GT7 stack flow rates are for 100% load conditions. When modeling for CO impacts, 25% load stack parameters were used to better represent the startup/shutdown stack conditions that match the highest CO emission rate scenario. The 25% load stack parameters include an exhaust temperature of 854 degrees F and an exit velocity of 60 fps.

While there are two emergency generators, they will not be simultaneously operated for testing or maintenance, therefore only one was modeled as operating at any given time.

5.8 PSD Modeling Analysis Results

A PSD air quality impact analysis is required only for the two criteria pollutants that trigger PSD review, CO and $PM_{2.5}$. The first step in the PSD analysis is the significant impact analysis, which estimates ambient concentrations resulting from the Project emission increases. When the maximum concentration of a pollutant is below the Significant Impact Level ("SIL"), no further air quality analysis is required for that pollutant and averaging interval. Preconstruction and background monitoring data have been identified in Sections 3.1 and 3.4 of this report, which demonstrates that the difference between the NAAQS and existing air quality concentrations is greater than the SILs. Therefore, there is adequate headroom between the existing air quality and the NAAQS to permit the use of the SILs for the modeling analyses.

The highest Project-only AERMOD predicted ambient concentrations are summarized in Table 7. All Project impacts are below the Significant Impact Levels, therefore a cumulative NAAQS and PSD increment analysis is not required.

Table 7 – PSD Significant Impact Modeling Results (ug/m3)

Pollutant	Averaging Interval	Highest Modeled Conc.	SILs	Impacts Above SIL?
CO	8-hour	60.5	500	No
	1-hour	343	2,000	No
$PM_{2.5}$	Annual	0.07	0.3	No
	24-hour	1.00	1.2	No

5.9 Facility NAAQS and Rule 32F Modeling Analysis Results

In addition to the PSD required modeling for $PM_{2.5}$ and CO, the MCAQD requested that facility-wide NAAQS modeling be performed that included all emission units at the facility after operation of the Project units begins. The facility wide modeling was performed for SO_2, NO_2, CO, and $PM_{2.5}$. Emissions that were modeled for the existing GT1, GT2, and emergency generator units are presented in Appendix B.

The facility-wide SO_2 modeling is also used to demonstrate compliance with Maricopa County SIP Rule 32 maximum SO_2 ambient concentrations. The 1-hour, 24-hour and 72-hour Rule 32 ambient limits are 850 µg/m3, 250 µg/m3 and 120 µg/m3, respectively. Because a 72-hour concentration is not output by AERMOD, the 24-hour modeled concentration was used for the 72-hour Rule 32 analysis (this is conservative because the 24-hour concentration will be higher than the 72-hour concentration).

The facility wide AERMOD predicted ambient concentrations are summarized in Table 8, along with the background concentration data and the NAAQS. The short-term CO and SO_2 impacts (not including the 1-hour SO_2 and 1-hour NO_2 impacts, which are based on the design concentrations for those pollutants) are the highest-second-high concentrations from any single year of meteorological data. All facility impacts, when added to the background concentrations, are below the NAAQS and demonstrate compliance with the NAAQS and the Rule 32 concentration limits.

Table 8 – Facility NAAQS and Rule 32 Modeling Results (ug/m3)

Pollutant	Averaging Interval	Cumulative Impact	Background	Total	NAAQS (Rule 32 Limit)	% of NAAQS
CO	8-hour	1231	1832	3063	10,000	31%
	1-hour	1733	2519	4252	40,000	11%
NO_2	Annual	0.7	37	38	100	38%
	1-hour	30.4	115	145	188	77%
SO_2	Annual	0.06	3	3	80	4%
	24-hour	0.16	21	21	365	6%
	3-hour	0.4	21	21	1,300	2%
	1-hour	0.2	21	21	196 (850)	11%
$PM_{2.5}$	24-hour	0.9	18	18.9	35	54%
	Annual	0.3	8.9	9.2	15	61%

Note: The 24-hour and 72-hour Rule 32 SIP ambient concentration limits are 250 µg/m3 and 120 µg/m3, respectively. The 24-hour modeled impacts are compared to the lower of these Rule 32 limits to conservatively demonstrate compliance.

6.0 Additional Impacts Analysis

The PSD rules requires an additional impact analysis for pollutants that trigger PSD review (for this Project, those pollutants are CO and $PM_{2.5}$). The purpose of this analysis is to assess the potential impact the proposed project will have on visibility, soils, and vegetation, as well as the impact of general commercial, residential, and industrial growth associated with the proposed project.

6.1 Analysis on Vegetation and Soils

The analysis of CO and $PM_{2.5}$ impacts on vegetation and soils of commercial or recreational value was based on an inventory of vegetation and soils in the Project area, and a comparison of AERMOD predicted air quality impacts of the Project to various effects thresholds.

The EPA Environmental Appeals Board (EAB) has discussed in the Indeck-Elwood LLC PSD Appeal No. 03-04, September 27, 2006, how the PSD vegetation and soils analysis procedures in EPA's 1990 *Draft New Source Review Workshop Manual* (NSR Manual) provide a proper framework for the analysis. The NSR Manual states that an analysis of soil and vegetation air pollution impacts "should be based on an inventory of the soil and vegetation types found in the impact area." Given the modeling results presented in Section 5.8, the Project will not result in significant impacts for CO and $PM_{2.5}$, and the locations of the maximum impacts are very close to the Project ambient air boundary. Therefore, the impact and inventory area that should be analyzed is the immediate vicinity of the Ocotillo Plant.

There are no commercial crops located in the immediate vicinity of the Ocotillo plant. The closest crop land is located approximately 1.5 km to the northeast of the plant, and the Project CO and $PM_{2.5}$ air quality impacts at that distance (and at the fence line) are insignificant. The ASU Karsten golf course is located immediately to the west and north of the Ocotillo power plant; APS donated 100 acres of land for the course in the 1970s, and the course opened in 1989. The air quality impacts of the current Ocotillo plant has not interfered with the golf course vegetation since operations began, and the Project air quality impacts have also been shown to be insignificant. Therefore, it is not anticipated that the Project will effect commercial or recreational vegetation in the area.

A soil survey for the area surrounding the Ocotillo plant was performed using the US Department of Agriculture Web Soil Survey (WSS) at http://websoilsurvey.nrcs.usda.gov/app/. Appendix A of this modeling report presents the detailed survey results. The survey results indicate that the predominate soil types located within an approximately 3 mile square area centered on the Ocotillo plant include Laveen, Avondale Clay, and Gilman loams, and general alluvial soil types. These are common soil types for the area, and do not represent any unique, sensitive soils that would be impacted by the Project.

As part of APS's Application for a Certificate of Environmental Compatibility ("CEC") to the Arizona Corporation Commission ("ACC"), APS submitted an inventory and analysis of fish, animal, and plant life within 3 miles of the Ocotillo Plant (CEC Exhibit C – Special Status Species and Species of Concern). The overall conclusions of the CEC analysis are that within the surrounding study area, the biotic environment has experienced high levels of disturbance with urban development in nearly the entire area. The Ocotillo site is a disturbed industrial area. Future operations would not change significantly from existing ones and there are no anticipated additional impacts on special status species or habitats.

The air quality impacts from the Project were compared to vegetation and soils threshold impact criteria in EPA's *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*, December 12, 1980, EPA 450/2-81-078. This document contains screening levels for CO impacts, but not $PM_{2.5}$ impacts. The CO screening threshold for sensitive vegetation is listed as 1000 ppm

(1,200,000 ug/m3) for a 1 week exposure (averaging interval). The Project and facility-wide CO impacts are orders of magnitude lower than this threshold. In addition, because the Project is fired using natural gas, there are no appreciable emissions of metals and Project impacts are far below any listed screening thresholds for soils and vegetation effects of metals.

Information on the sensitivities of vegetation to NO_2 ambient concentrations is also found in EPA's "Air Quality Criteria for Oxides of Nitrogen, Summary of Vegetation Impacts" Volume II, August 1993 (EPA 600/8-91/049bF). For susceptible plant species, 1-hr NO_2 exposures to approximately 7,500 ug/m3 can cause 5% foliar injury. Even though the Project does not trigger PSD review for NOx, a facility wide modeling analysis indicated that maximum 1-hr impacts including background are 145 ug/m3. This maximum ambient concentration is far lower than the susceptible plant species effects threshold.

EPA's draft NSR Manual states that "For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary [NAAQS] will not result in harmful effects." The NAAQS secondary standards are intended to protect public welfare, including the consideration of economic interests, vegetation, and visibility. Neither the Project impacts, nor the Ocotillo facility-wide impacts, are greater than the primary or secondary NAAQS.

In summary, based on an inventory of soils and vegetation and comparison of Project air quality impacts to the NAAQS and various screening threshold, it can be concluded that the Project will not have an adverse impact on soils and vegetation.

6.2 Analysis on Visibility

Based on consultations with MCAQD and ADEQ, a Class II area visibility analysis was performed for the three nearby parks, the City of Phoenix Camelback Mountain and South Mountain Parks and the Tres Rios wetlands area. VISCREEN was used to assess visibility impacts at these locations. Note that there are no established adverse effects thresholds for Class II visibility analyses.

The VISCREEN model is a screening technique used to estimate the mass of pollutant in the atmosphere and its ability to scatter or absorb light and, therefore, to affect visibility. The VISCREEN model calculates rudimentary scattering and absorption coefficients and these values are compared to screening threshold levels to determine the potential magnitude and type of coherent plume visibility impairment. Two measures of potential plume effects are used. One is a measure of plume contrast, which is the change in light extinction coefficient between views against a background feature (either sky or terrain) and views against the plume. The other measure is delta E, the total color contrast, which takes into account plume intensity, color, and brightness. If the plume is brighter than its background, it will have a positive contrast. If the plume is darker than its background, it will have a negative contrast. VISCREEN assumes that a terrain object is black, which maximizes the contrast. VISCREEN can be run with simple "worst-case" meteorology, referred to as a "Level 1" analysis, or in a more refined mode based on an analysis of actual meteorological conditions, referred to as a "Level 2" analysis.

The emissions used for the VISCREEN analysis are based on a worst-case 24-hr scenario that included unlimited startup emissions for NO_X (31.4 lb/hr for each GT) and full load emissions for $PM_{2.5}$ (5.4 lb/hr for each GT) for all 5 GTs concurrently. Given the intermittent nature of the emergency generators, they are not included in the analysis. Other VISCREEN inputs include the default particle characteristics and plume-source-observer angle, and an ozone background concentration of 0.077 ppm based on the maximum 8-hr average ozone at the Tempe monitoring station in 2013.

The ADEQ monitors visibility in the Phoenix area and reports data at the web page http://www.phoenixvis.net/vis-index.aspx. Data from 2013 indicates that the measured visibility for the majority of the days (226 out of 365) was in the Good category (ranging from 15 to 20 deciviews). Conservatively using the best visibility value in this range (15 deciviews), and converting it to visual range, the existing background visual range in the Phoenix area is calculated at 90 km. This visual range was used for the Class II area VISCREEN analyses.

Because a similar near-field visibility analysis was performed for the Class I Superstition Mountain Wilderness area (see Section 7.3 of this protocol), and Level 2 meteorological data was used for that analysis, Level 2 meteorological data was also used for the Class II area VISCREEN analyses. The Level 2 assessment was based on 5 years of hourly ISC meteorological data for Sky Harbor airport processed by ADEQ, along with the Iowa Department of Natural Resources "VISCREEN Tool" spreadsheet analysis tool (which calculates the frequency of occurrence data needed to conduct the Level-2 VISCREEN analysis in accordance with the VISCREEN user's manual and guidance documents). Table 9 presents the VISCREEN parameters and observer geometries that were used for the Level 2 analyses at these three Class II areas.

Table 9 - VISCREEN Parameters for Class II Visibility Analysis

	Camelback Mountain	South Mountain	Tres Rios Wetlands
Minimum Distance (km)	10	12	32
Maximum Distance (km)	13	27	34
Sector for Transport of Emissions from Source to Area	325 to 340 degrees	230 to 250 degrees	260 to 265 degrees
Level 2 Stability Class	E	F	E
Level 2 Wind Speed	4	2	3

Table 10 presents the VISCREEN Class II analysis results for "Inside the Class II area". There are no specific impact thresholds that apply to a Class II visibility modeling analysis.

Table 10 - VISCREEN Class II Visibility Analysis Results

	Camelback Mountain	South Mountain	Tres Rios Wetlands
Maximum Delta E	1.64	5.72	0.47
Maximum Contrast	0.008	0.059	0.004

6.3 Associated Growth and Secondary Emissions Analysis

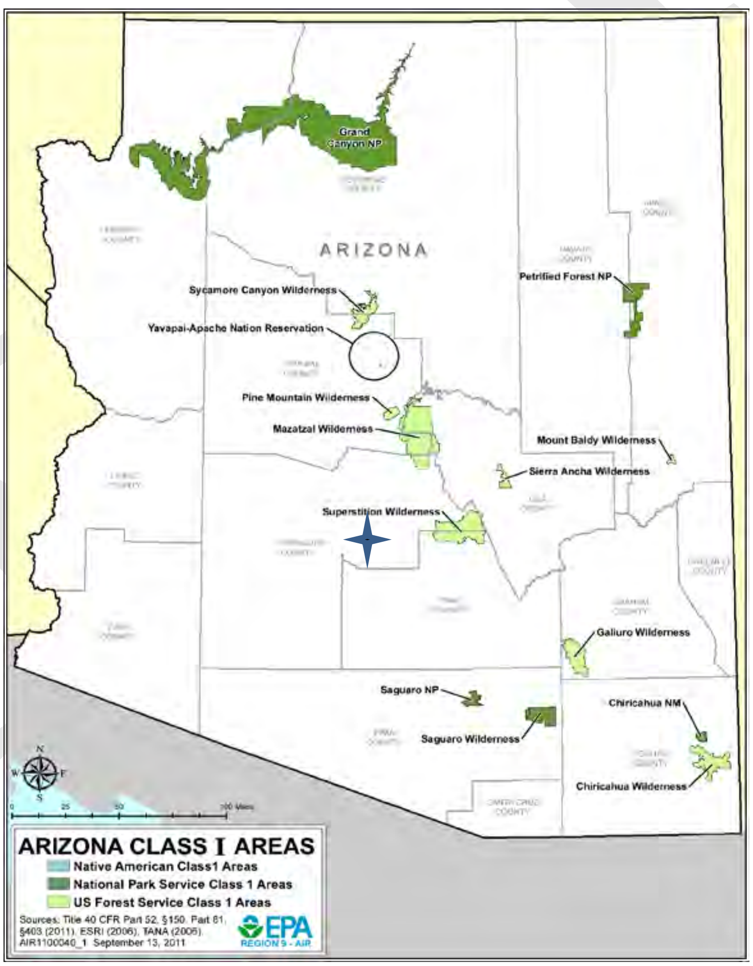
The emissions resulting from residential, commercial, and industrial growth associated with, but not directly a part of the project, must also be considered when conducting the air quality analysis. Given the large local population and the limited construction related activities associated with this Project, the construction associated with the Project will not have a significant impact to the local population. Further, since the Ocotillo Power Plant is an existing power plant, the employees required to operate the facility are already largely hired and available, so that further impacts to the local area will be small. In addition, local municipal services will not be adversely impacted by this Project. Therefore, the Project is not expected to have a measurable effect on the residential, commercial, or industrial growth of the area.

7.0 Class I Area Analyses

The PSD regulations require that major sources and major modifications which may affect a Class I area (i.e., are generally located within 100 km of a Class I area) must notify the Federal Land Managers (FLMs) of the project. The permit applicant typically performs a Class I PSD Increment analysis and an Air Quality Related Values (AQRVs) analysis for any AQRVs that the FLMs have identified for the specific Class I area(s). In addition, projects with large emission increases that are located beyond 100 km but within 300 km from a Class I area may also be requested to conduct an impact analysis by the FLMs. The FLM's *Air Quality Related Values Work Group (FLAG) Phase I Report – Revised* (FLAG 2010) provides guidance on methodologies for conducting Class I air quality impact analyses.

Figure 12 presents a map showing the locations of Class I areas within Arizona relative to the Ocotillo Plant (shown as a blue star). The four Class I areas located within 100 km of the Project include the Superstition Wilderness Area (WA), the Sierra Ancha WA, the Pine Mountain WA, and the Mazatzal WA. All of the other Class I areas in Arizona are located more distant than 100 km but within 300 km of the Project location.

Figure 12 – Locations of Class I Areas relative to the Project



The Ocotillo Project triggers PSD review for the criteria pollutants CO and $PM_{2.5}$. There are no Class I PSD increments for CO, and CO does not contribute to visibility or other AQRV degradation, therefore Class I analyses are not required for CO. Class I PSD $PM_{2.5}$ increment analyses were performed, as well as any required AQRV analyses.

7.1 Class I $PM_{2.5}$ PSD Increment Analyses

Section 5.8 of this protocol discusses the current EPA guidance for performing $PM_{2.5}$ increment analyses. EPA has stated that because the $PM_{2.5}$ minor source increment trigger date has only relatively recently been established (i.e., October 20, 2011), for the next several years a new or modified source being evaluated for $PM_{2.5}$ increments compliance will often be the first source with increment-consuming emissions in the area. Under this situation, a permitting authority may have sufficient reason to conclude that the impacts of the new or modified source may be compared directly to the allowable increments, without the need for a cumulative increment modeling analysis. Such a situation would involve the new or modified source representing the first PSD application in the area after the trigger date, which establishes the minor source baseline date and baseline area, and confirmation that no relevant major source construction has already occurred since the major source baseline date.

Based on discussions with MCAQD and ADEQ, it has been determined that there have not been any construction-related $PM_{2.5}$ emission increases at major sources that have been permitted since the major source baseline date, and that the only $PM_{2.5}$ minor source increment date that has been triggered in Arizona is for the Cochise County baseline area by the Southwestern Power Bowie PSD project. This project did not result in an annual $PM_{2.5}$ impact greater than 0.3 µg/m3 in any Class I area (one of the triggering criteria for establishing the minor source baseline date in Class I areas), but because the Chiricahua National Monument and Chiricahua WA are also located in Cochise County, the minor source baseline dates have been triggered in those Class I areas. For all other Class I areas in Arizona, the $PM_{2.5}$ minor source baseline date has not been triggered. The Ocotillo Project PSD permit application triggers the $PM_{2.5}$ minor source baseline date in the Maricopa County baseline area and those portions of the Superstition WA and the Mazatzal WA that are contained within Maricopa County.

Based on these baseline dates, the only $PM_{2.5}$ increment consuming emissions in Maricopa County and at all Class I areas besides Chiricahua National Monument (NM) and Chiricahua WA at the time of the Ocotillo Project PSD permit application are the Ocotillo Project emissions. Therefore, it can be concluded that the model predicted Ocotillo Project Class I $PM_{2.5}$ increment impacts may be directly compared to the allowable increments at all Class I areas besides the Chiricahua NM and Chiricahua WA. For those two areas, the model predicted Ocotillo Project Class I $PM_{2.5}$ increment impacts were added to the maximum impacts reported for the Bowie project and the total was compared to the $PM_{2.5}$ increments (this is a very conservative approach, since the Ocotillo and Bowie impacts would not be spatially or temporally paired).

As described below in Section 7.2, the CALPUFF model does not need to be used for a Class I AQRV analysis. Therefore, a conservative AERMOD modeling analysis was performed to determine the Ocotillo Project impacts to the Class I $PM_{2.5}$ increments. AERMOD was run with the Superstition Class I area receptors (obtained from the National Park Service web page) that are within 50km of Ocotillo. In addition, two receptor rings located 25km and 50km distant from Ocotillo were modeled with AERMOD. The model predicted $PM_{2.5}$ concentrations at the 25km and 50km receptor rings were analyzed to document that the impacts are decreasing with distance. Then, the highest predicted annual and 24-hr $PM_{2.5}$ impacts from either the Superstition receptors or the 50km receptor ring were directly compared to the PSD SILs and increments at the four Class I areas located within 100km from Ocotillo. In addition, the same highest predicted Ocotillo impacts were added to the maximum impacts reported for the Bowie project and the totals were compared to the $PM_{2.5}$ increments at the Chiricahua NM and Chiricahua WA Class I areas. This procedure also meets EPA recommendations for determining if Class I PSD increment analyses are necessary beyond 50 km, as discussed in the recently proposed 40 CFR Part 51 Appendix W revisions. EPA recommends that a near-field model such as AERMOD be used to determine the significance of the ambient impacts at or about 50 km from the source, and if this initial analysis indicates there will not be significant ambient impacts at that distance then further assessment using long-range models is not necessary.

The highest predicted annual and 24-hr $PM_{2.5}$ impacts from the Ocotillo Project emission units at either the Superstition receptors or the 50km receptor ring are 0.016 ug/m3 and 0.06 ug/m3, respectively. These impacts are less than the annual and 24-hr $PM_{2.5}$ PSD Class I SILS of 0.2 and 0.3 ug/m3, and the annual and 24-hr $PM_{2.5}$ PSD Class I increments of 1 ug/m3 and 2 ug/m3, respectively. Even when adding the highest predicted annual and 24-hr $PM_{2.5}$ impacts from the Bowie Project of ? ug/m3 and 0.07 ug/m3, respectively, the total impacts are appreciably lower than the PSD increments. Therefore, this analysis demonstrates that the Project will not cause or contribute to an exceedance of the Class I $PM_{2.5}$ PSD increments.

7.2 Class I AQRV Analysis Requirements

The FLAG 2010 guidance has developed an initial screening method that exempts a project from AQRV impact analysis and review based on its annual emissions and distance from a Class I area. The FLMs will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if the total SO_2, NO_X, PM_{10}, and H_2SO_4 annual emissions (in tpy, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I, area (Q/D) is 10 or less. The Agencies would not request any Class I AQRV impact analyses from such sources. Because the Ocotillo Project annual emissions for these four pollutants are limited by the annual fuel use restrictions, a more representative “maximum 24-hr” tpy emission calculation was based on 20 SU/SD sequences per day for all five GTS and unlimited full load operations for the remaining hours in the day; this results in 24-hr average emission rates per turbine of 13.0 lb/hr for NO_X (4 hours at 31.4 lb/hr and 20 hours at 9.3 lb/hr), 5.4 lb/hr for $PM_{2.5}$, and 0.66 lb/hr for SO_2 and sulfuric acid mist combined. For all 5 turbines, this equates to an equivalent tpy emission rate of 417 tpy for the combined SO_2, NO_X, PM_{10}, and sulfuric acid mist potential emissions from the Project. The calculated Q/D value is 8.3 at a distance of 50 km, which is less than the FLAG AQRV analysis threshold of 10. Therefore, AQRV analyses will not be required for any Class I area equal to or further than 50 km from the Ocotillo plant.

However, a portion of the closest Class I area to the Project site, the Superstition Wilderness Area, is located approximately 43 km to the east. Because the Q/D method cannot be used for Class I areas within 50 km of a project, AQRV analyses were performed for that portion of the Superstition Wilderness Area within 50 km from the Project (i.e., in the “near-field”). The near-field AQRV analyses consisted of a visibility analysis using the VISCREEN model, as described below in Section 7.3. A near-field sulfur and nitrogen deposition AQRV analysis was also be performed, even though the Project does not trigger PSD review requirements (including Class I analysis requirements) for the pollutants NO_X and SO_2 (the Project net emission increases of those pollutants are below the Significant Emission Rates of 40 tpy).

7.3 Near-field Visibility AQRV Analysis

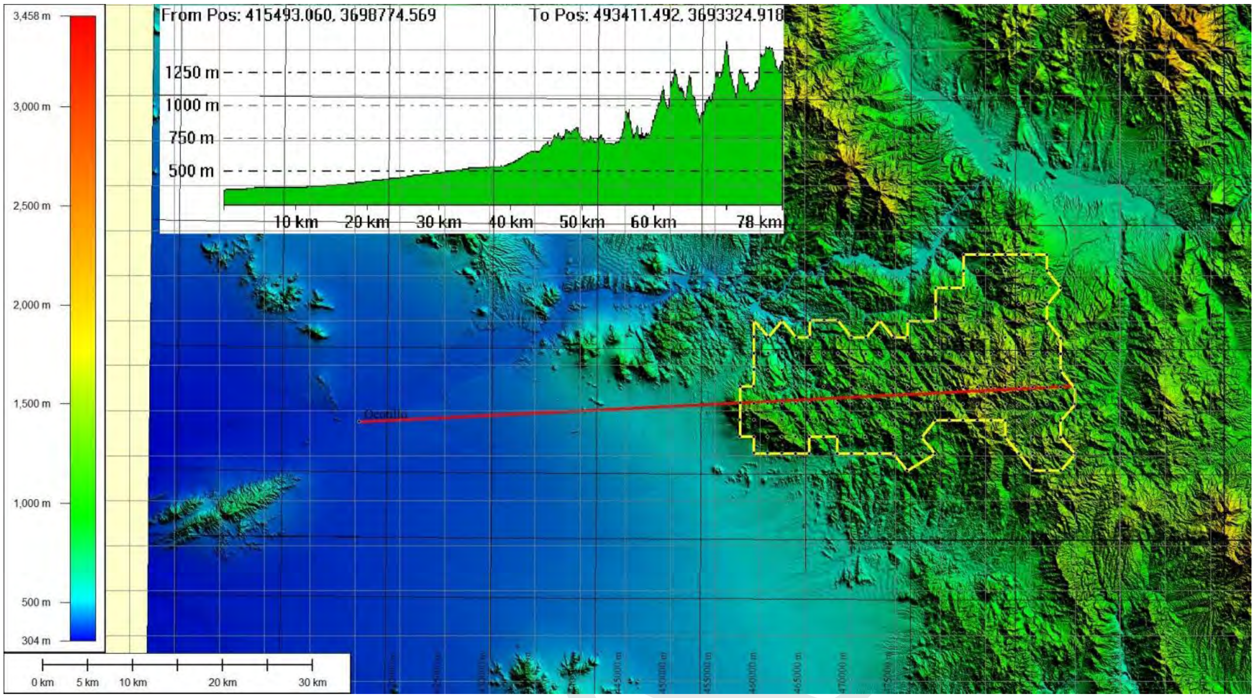
VISCREEN was used to assess near-field visibility impacts in the Superstition Wilderness Area (WA). The VISCREEN model is a screening technique used to estimate the mass of pollutant in the atmosphere and its ability to scatter or absorb light and, therefore, to affect visibility. The VISCREEN model calculates rudimentary scattering and absorption coefficients and these values are compared to screening threshold levels to determine the potential magnitude and type of coherent plume visibility impairment. Coherent plume impacts occur when a visible plume or colored layer is visible against the sky or distant terrain features. Coherent plume impacts may occur in areas that are close to a source of pollutants, while uniform haze may occur further downwind. Two measures of potential plume effects are used. One is a measure of plume contrast, which is the change in light extinction coefficient between views against a background feature (either sky or terrain) and views against the plume. The other measure is delta E, the total color contrast, which takes into account plume intensity, color, and brightness. If the plume is brighter than its background, it will have a positive contrast. If the plume is darker than its background, it will have a negative contrast. VISCREEN assumes that a terrain object is black, which maximizes the contrast. VISCREEN can be run with simple "worst-case" meteorology, referred to as a "Level 1" analysis, or in a more refined mode based on an analysis of actual meteorological conditions, referred to as a "Level 2" analysis.

The emissions used for the VISCREEN analysis were based on the maximum 24-hr emission scenario described in Section 7.2 with 24-hr average emission rates per turbine of 13.0 lb/hr for NO_X and 5.4 lb/hr for $PM_{2.5}$. Given the intermittent nature of the emergency generators, they were not included in the analysis. Even though the emissions from the cooling tower are not buoyant and are not likely to be transported to the Class I area, the cooling tower $PM_{2.5}$ emissions of 0.24 lb/hr were included in the visibility screening analyses. For the five turbines and the cooling tower combined, the total emissions are 65.0 lb/hr for NO_X and 27.2 lb/hr for $PM_{2.5}$. Other VISCREEN inputs include the default particle characteristics and plume-source-observer angle, and an ozone background concentration of 0.077 ppm based on the maximum 8-hr average ozone at the Tempe monitoring station in 2013. The estimated natural background visual range for the Superstition Wilderness area is 264 km based on the month of July, as listed in Table 10 of the FLAG 2010 guidance document.

A preliminary Level 1 assessment was performed, using worst-case meteorology of F stability class and 1 m/s wind speed. The Level-1 results indicated that a more refined Level 2 analysis was needed. The Level 2 assessment was based on 5 years of hourly ISC meteorological data for Sky Harbor airport processed by ADEQ, along with the Iowa Department of Natural Resources "VISCREEN Tool" spreadsheet analysis tool, which calculates the frequency of occurrence data needed to conduct the Level-2 VISCREEN analysis in accordance with the VISCREEN user's manual and guidance documents. The Superstition Wilderness Area is located in a 75 to 94 degree wind sector (directions from the source to the area) relative to the Ocotillo Plant, at distances ranging from 42.8 km to 50 km (VISCREEN is only used to evaluate impacts out to 50 km). The frequency of occurrence of all meteorological conditions in this wind sector has been evaluated and the resulting meteorological conditions are F stability and 3 m/sec wind speed. The VISCREEN user's manual also recommends evaluating the complexity of the terrain before determining the final Level 2 meteorological values. If the elevation of the observer in the Class I area is 500m higher than the effective stack height for stable conditions, or if such terrain exists between observer and source, the VISCREEN user's manual recommends to increase the stability class by 1 unit. Figure 13 presents a cross section of the elevation differences between the Ocotillo project location and the Superstition WA. The Superstition WA contains terrain with elevations more than 1000 meters higher than the stack elevation at the Ocotillo plant, therefore it is reasonable to increase the stability class by 1 unit in this analysis. Therefore, the final Level 2 meteorological conditions that were used are E stability and 3 m/sec wind speed.

The VISCREEN analysis results inside the Class I area include a maximum delta E value of 1.65, and a maximum contrast value of 0.014. Both of these values are below the screening criteria values of 2.00 for delta E and 0.05 for contrast, therefore the Class I screening criteria will not be exceeded.

Figure 13 – Terrain Elevations in Superstition WA



Notes: The red line represents the longest potential sight path in the Class I area. The elevation profile shows the extreme elevation differences between the Ocotillo plant and the Class I area.

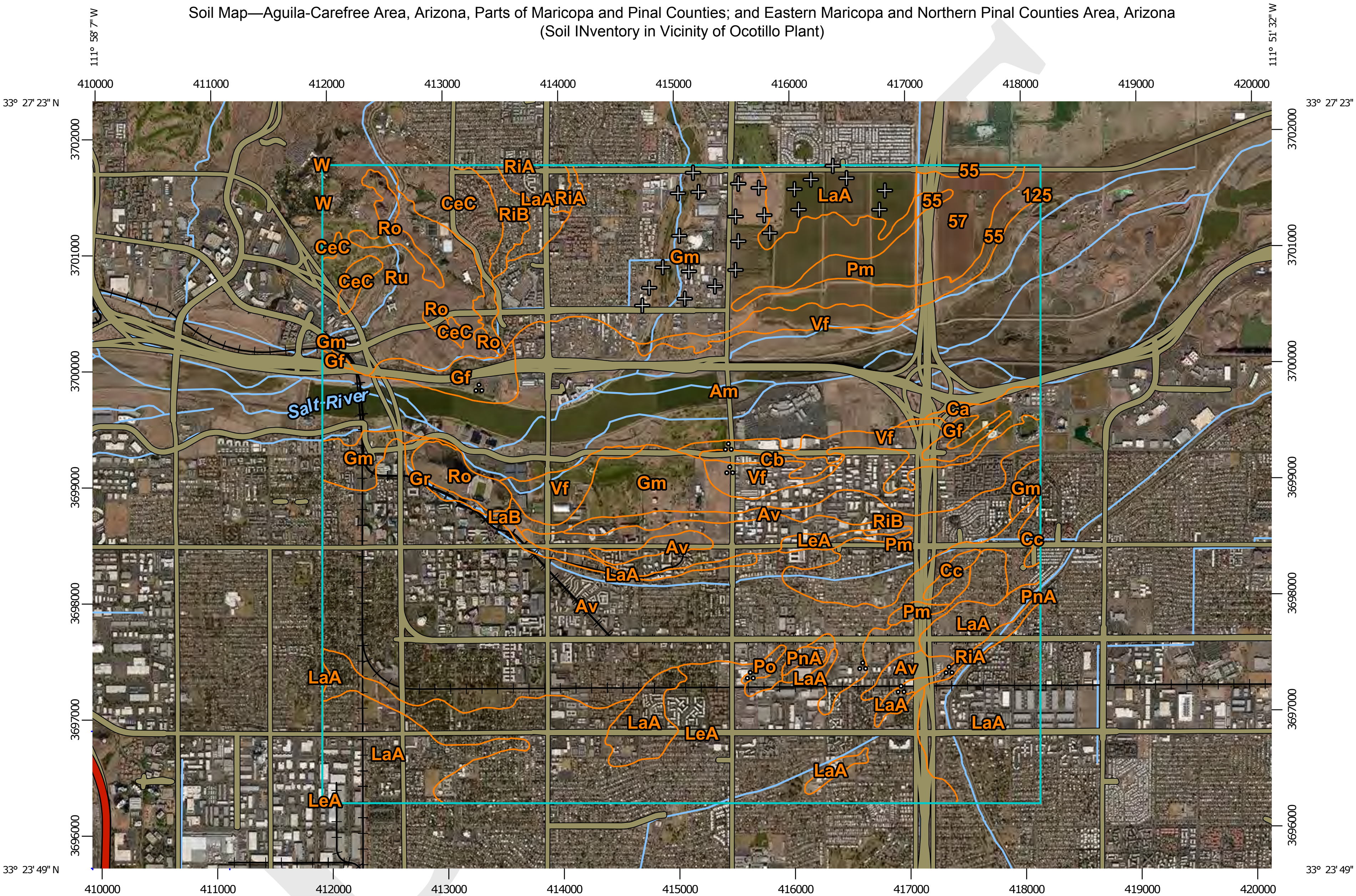
7.3 Near-field Nitrogen Deposition AQRV Analysis

Even though the Project does not trigger PSD review requirements (including Class I analysis requirements) for the pollutants NO_X and SO_2 (the Project net emission increases of those pollutants are below the Significant Emission Rates of 40 tpy), a near-field nitrogen and sulfur deposition AQRV analysis was performed. The analysis was based on guidance in the document "*Federal Land Managers' Interagency Guidance for Near-Field Deposition Modeling (DRAFT)*". USDA Forest Service, US Fish & Wildlife Service, and National Park Service, January 2014. A Level-1 analysis was performed by modeling the Project's net annual emission increases of SO2 and NOx (using a single CTG stack) in AERMOD using the FLM Class I receptor grid, and outputting annual deposition fluxes.

The maximum annual modeled nitrogen and sulfur deposition values are 0.0011 and 0.00003 $gr/m^2/yr$. After performing the Level-1 calculations on these model results, the final nitrogen and sulfur deposition rates are 0.0033 kg/ha-yr and 0.0002 kg/ha-yr. These deposition rates are below the Deposition Analysis Thresholds (DATs) for western Class I areas of 0.005 kg/ha-yr. Therefore, the Project impacts are below the screening thresholds for nitrogen and sulfur deposition at the portion of the Superstition Class I area that is within 50 km of the Project.

APPENDIX A – SOIL SURVEY RESULTS

Soil Map—Aguila-Carefree Area, Arizona, Parts of Maricopa and Pinal Counties; and Eastern Maricopa and Northern Pinal Counties Area, Arizona
(Soil INventory in Vicinity of Ocotillo Plant)



Map Scale: 1:46,600 if printed on A landscape (11" x 8.5") sheet.

Meters: 0, 500, 1000, 2000, 3000

Feet: 0, 2000, 4000, 8000, 12000

N

Map projection: Web Mercator Corner coordinates: WGS84 Edge tics: UTM Zone 12N WGS84

MAP LEGEND

Area of Interest (AOI)
- Area of Interest (AOI)

Soils
- Soil Map Unit Polygons
- Soil Map Unit Lines
- Soil Map Unit Points

Special Point Features
- Blowout
- Borrow Pit
- Clay Spot
- Closed Depression
- Gravel Pit
- Gravelly Spot
- Landfill
- Lava Flow
- Marsh or swamp
- Mine or Quarry
- Miscellaneous Water
- Perennial Water
- Rock Outcrop
- Saline Spot
- Sandy Spot
- Severely Eroded Spot
- Sinkhole
- Slide or Slip
- Sodic Spot
- Spoil Area
- Stony Spot
- Very Stony Spot
- Wet Spot
- Other
- Special Line Features

Water Features
- Streams and Canals

Transportation
- Rails
- Interstate Highways
- US Routes
- Major Roads
- Local Roads

Background
- Aerial Photography

MAP INFORMATION

The soil surveys that comprise your AOI were mapped at scales ranging from 1:20,000 to 1:24,000.

Please rely on the bar scale on each map sheet for map measurements.

Source of Map: Natural Resources Conservation Service
Web Soil Survey URL: http://websoilsurvey.nrcs.usda.gov
Coordinate System: Web Mercator (EPSG:3857)

Maps from the Web Soil Survey are based on the Web Mercator projection, which preserves direction and shape but distorts distance and area. A projection that preserves area, such as the Albers equal-area conic projection, should be used if more accurate calculations of distance or area are required.

This product is generated from the USDA-NRCS certified data as of the version date(s) listed below.

Soil Survey Area: Aguila-Carefree Area, Arizona, Parts of Maricopa and Pinal Counties
Survey Area Data: Version 9, Sep 14, 2014

Soil Survey Area: Eastern Maricopa and Northern Pinal Counties Area, Arizona
Survey Area Data: Version 7, Sep 14, 2014

Your area of interest (AOI) includes more than one soil survey area. These survey areas may have been mapped at different scales, with a different land use in mind, at different times, or at different levels of detail. This may result in map unit symbols, soil properties, and interpretations that do not completely agree across soil survey area boundaries.

Soil map units are labeled (as space allows) for map scales 1:50,000 or larger.

Date(s) aerial images were photographed: Nov 2, 2010—Jan 20, 2015

The orthophoto or other base map on which the soil lines were compiled and digitized probably differs from the background imagery displayed on these maps. As a result, some minor shifting of map unit boundaries may be evident.

Map Unit Legend

Aguila-Carefree Area, Arizona, Parts of Maricopa and Pinal Counties (AZ645)			
Map Unit Symbol	**Map Unit Name**	**Acres in AOI**	**Percent of AOI**
55	Gilman loams	82.6	1.0%
57	Gilman clay loam	137.2	1.6%
125	Vint loamy fine sand	1.2	0.0%
Subtotals for Soil Survey Area		**220.9**	**2.6%**
Totals for Area of Interest		**8,475.6**	**100.0%**

Eastern Maricopa and Northern Pinal Counties Area, Arizona (AZ655)			
Map Unit Symbol	**Map Unit Name**	**Acres in AOI**	**Percent of AOI**
Am	Alluvial land	1,392.0	16.4%
Av	Avondale clay loam	1,669.5	19.7%
Ca	Carrizo gravelly loamy sand	3.4	0.0%
Cb	Carrizo fine sandy loam	29.4	0.3%
Cc	Cashion clay	31.0	0.4%
CeC	Cavelt gravelly loam, 1 to 5 percent slopes	166.0	2.0%
Gf	Gilman fine sandy loam	120.1	1.4%
Gm	Gilman loam	1,290.4	15.2%
Gr	Gravelly alluvial land	19.6	0.2%
LaA	Laveen loam, 0 to 1 percent slopes	1,020.8	12.0%
LaB	Laveen loam, 1 to 3 percent slopes	3.4	0.0%
LeA	Laveen clay loam, 0 to 1 percent slopes	1,056.0	12.5%
Pm	Pimer clay loam	458.1	5.4%
PnA	Pinal gravelly loam, 0 to 1 percent slopes	12.3	0.1%
Po	Pinal loam, moderately deep variant	10.0	0.1%
RiA	Rillito gravelly loam, 0 to 1 percent slopes	41.1	0.5%
RiB	Rillito gravelly loam, 1 to 3 percent slopes	51.1	0.6%
Ro	Rock land	125.1	1.5%
Ru	Rough broken land	397.7	4.7%
Vf	Vint loamy fine sand	357.3	4.2%
W	Water	0.1	0.0%
Subtotals for Soil Survey Area		**8,254.6**	**97.4%**
Totals for Area of Interest		**8,475.6**	**100.0%**

APPENDIX B – EMISSIONS FOR EXISTING

GT1, GT2, AND EMERGENCY GENERATOR

UNITS

Potential emissions for the existing General Electric Frame 501 GT1 and GT2 gas turbines.

POLLUTANT		Emission Factor	Heat Input	Estimated Operation	Potential to Emit Each Turbine		Potential to Emit, Both Turbines
		lb/mmBtu	mmBtu/hr	hour/yr/turbine	lb/hr	tons/yr	tons/yr
Carbon Monoxide	CO	0.082	937	1,600	76.83	61.5	122.9
Nitrogen Oxides	NO_x	0.320	937	1,600	299.84	239.9	479.7
Particulate Matter	PM	0.0083	937	1,600	7.73	6.2	12.4
Particulate Matter	PM_{10}	0.0083	937	1,600	7.73	6.2	12.4
Particulate Matter	$PM_{2.5}$	0.0083	937	1,600	7.73	6.2	12.4
Sulfur Dioxide	SO_2	0.0006	937	1,600	0.56	0.4	0.9

Footnotes

1. Emission factors taken from the U.S. EPA's *Compilation of Air Pollutant Emission Factors*, *AP-42,* 5th Edition, Table 3.1-1 and 3.1-2a.

Potential emissions for existing propane-fired 125 hp emergency generator.

POLLUTANT		Emission Factor	Heat Input	Emission Factor	Power Output	Potential Emissions	
		lb/MMBtu	MMBtu/hr	g/hp-hr	hp	lb/hr	ton/year
Carbon Monoxide	CO	NA	NA	129.1	125	35.55	8.89
Nitrogen Oxides	NO_x	NA	NA	4.32	125	1.19	0.30
Particulate Matter	PM	0.0194	1.49	NA	NA	0.03	0.01
Particulate Matter	PM_{10}	0.0194	1.49	NA	NA	0.03	0.01
Particulate Matter	$PM_{2.5}$	0.0194	1.49	NA	NA	0.03	0.01
Sulfur Dioxide	SO_2	0.00059	1.49	NA	NA	0.0009	0.0002

Footnotes

1. Potential emissions are based on 500 hours per year of operation.
2. The CO, NO_x, and VOC (THC) emission rates are based on manufacturer's data.
3. PM and SO_2 emissions are based on fuel flow rate of 69.18 lb/hr, a heat content of 21,561 Btu/lb HHV, and AP-42 natural gas fired 4-stroke rich burn engines emission factors.

Appendix I - Environmental Justice Analysis for APS Ocotillo Modernization Project

Introduction

As part of the Prevention of Significant Deterioration (PSD) permitting activities for the Ocotillo Modernization Project (the Project), Arizona Public Service (APS) has prepared this Environmental Justice (EJ) analysis to address potential EJ issues. EPA Region 9 has previously prepared an EJ analysis for the Pio Pico Energy Center PSD permit in June 2012, and the Ocotillo EJ analysis has been based on the EPA analysis. In their EJ analysis, EPA described the requirements for an EJ analysis as follows:

Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations," states in relevant part that "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." Federal agencies are required to implement this order consistent with, and to the extent permitted by, existing law. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Clean Air Act (CAA) Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices and states acting under delegations of Federal authority. EPA Regional Offices or their delegates in the states have for several years incorporated environmental justice considerations into their review of applications for PSD permits.

For purposes of an EJ analysis, EAB has recognized that compliance with the applicable National Ambient Air Quality Standards (NAAQS) is indicative of achieving a level of public health protection that demonstrates that issuance of a PSD permit will not have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations. This is because the NAAQS are health-based standards, designed to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics.

Project Location, Description, and Applicable Air Permitting Regulations

The Ocotillo Power Plant is located at 1500 East University Drive, Tempe Arizona, 85281, in Maricopa County. Tempe is located in the East Valley section of metropolitan Phoenix; it is bordered by Phoenix and Guadalupe on the west, Scottsdale on the north, Chandler on the south, and Mesa on the east. Tempe is an "inner suburb", located between the core city of Phoenix and the rest of the East Valley. Due to this as well as being the home of the main campus of Arizona State University, Tempe has a fairly dense, urbanized development pattern in the northern part of the city. Going south, development becomes less dense, consisting of single-family homes, strip malls and lower-density office parks. Tribal lands located within 50 km of the Project include the Salt River, Gila River, and Ft. McDowell Indian Reservations.

The Ocotillo Plant has been in operation since 1960. The existing facility consists of two 110 Mw steam boiler generating units and two 55 Mw simple cycle gas turbine generators (GTs). APS is planning to install five new natural gas-fired GE Model LMS100 simple cycle GTs, a hybrid cooling tower system, two emergency diesel-fired 2.5 MW generators, and support equipment. The new GTs will be equipped with high efficiency pollution control systems, including Selective Catalytic Reduction (SCR) and oxidation catalyst systems. In addition, the new GTs will be limited to burning clean natural gas. As part of this 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. The Ocotillo site is a currently industrialized area and any ground-disturbing impacts would be confined to the

Ocotillo site itself. Operations would remain similar to current operations.

Table 1 presents the emission increases of the Project, and the applicable PSD permitting thresholds. Based on the regulatory analysis presented in the permit application, it has been shown that PSD permitting requirements apply to the Project only for the criteria pollutants CO and PM/$PM_{2.5}$.

TABLE 1. Project net emissions increase and PSD applicability. All emissions are tons per year.

POLLUTANT		Requested Allowable Project Emissions	Creditable Emission Decreases	Net Emission Increase	Significant Level	Over?
Carbon Monoxide	CO	249.9	14.6	235.3	100	**YES**
Nitrogen Oxides	NO_X	125.3	85.9	39.4	40	**NO**
Particulate Matter	PM	60.9	8.0	52.9	25	**YES**
Particulate Matter	$PM_{2.5}$	56.5	5.3	51.2	10	**YES**
Sulfur Dioxide	SO_2	5.9	0.4	5.5	40	**NO**
Sulfuric Acid Mist	H_2SO_4	0.6	0.0	0.6	7	**NO**
Fluorides (as HF)	HF	0.001	0.0	0.0	3	**NO**
Lead	Pb	0.005	0.0003	0.005	0.6	**NO**

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 are not compared to significance levels.

APS has performed a PSD air quality impact analysis for CO and $PM_{2.5}$, and has also conducted NAAQS air quality modeling for pollutants that do not trigger PSD review, including SO2 and NO2. Details on the computer models used, input data, modeling procedures, and results can be found in the *Title V Operating Permit Revision and Prevention of Significant Deterioration Air Pollution Control Permit Application for the Ocotillo Power Plant Modernization Project, Appendix F: Air Quality Analysis*. Table 2 presents a summary of the air quality modeling analyses for the PSD pollutants, and Table 3 presents the facility-wide NAAQS analysis results. The air quality impact analyses demonstrate that the Project complies with the NAAQS for all pollutants (the Project does not cause or contribute to a violation of the NAAQS).

TABLE 2. Results of PSD Air Quality Analysis (ug/m3)

Pollutant	Averaging Interval	Highest Modeled Conc.	SILs	Impacts Above SIL?
CO	8-hour	60.5	500	No
	1-hour	343	2,000	No
$PM_{2.5}$	Annual	0.07	0.3	No
	24-hour	1.00	1.2	No

TABLE 3. Results of NAAQS Air Quality Analysis (ug/m3)

Pollutant	Averaging Interval	Cumulative Impact	Background	Total	NAAQS	% of NAAQS
CO	8-hour	1231	1832	3063	10,000	31%
	1-hour	1733	2519	4252	40,000	11%
NO_2	Annual	0.7	37	38	100	38%
	1-hour	30.4	115	145	188	77%
SO_2	Annual	0.06	3	3	80	4%
	24-hour	0.16	21	21	365	6%
	3-hour	0.4	21	21	1,300	2%
	1-hour	0.2	21	21	196	11%
$PM_{2.5}$	24-hour	0.9	18	18.9	35	54%
	Annual	0.3	8.9	9.2	15	61%

Since EPA has previously determined that compliance with the applicable NAAQS is sufficient to satisfy the Executive Order as to the pollutants regulated under the PSD program, it can be concluded that the Project will not result in disproportionately high and adverse human health or environmental effects on minority populations and low-income populations. Additional information on air quality in the Project Area, demographics, and public participation/outreach activities is presented in the following sections.

Air Quality in the Project Area

The Ocotillo Power Plant is located in the City of Tempe, Maricopa County, Arizona. The area is currently designated nonattainment for PM_{10} (classification of serious), and for the 1997 and 2008 8-hour ozone standards (classification of marginal). The area is designated as a maintenance area for CO and attainment/unclassifiable for all other criteria pollutants.

The Air Monitoring Division of Maricopa County Air Quality Division collects accurate and timely ambient air quality monitoring data within Maricopa County. In cooperation with the EPA and other governmental agencies, the Division operates 24 air quality sites which measure for a number of criteria pollutants, including $PM_{2.5}$ and CO, and regularly reports on the monitoring station objectives and data results in periodic Network Plans and Network Assessments. The Division operates three monitoring stations located within 6 km of the Ocotillo plant, and which triangulate the Ocotillo Plant. Table 3 presents the maximum measured CO concentrations and the $PM_{2.5}$ monitoring design concentrations for these stations for 2012-2014, and the NAAQS, as reported in EPA's AQS data base at http://www.epa.gov/airdata/ad_rep_mon.html .

Table 3 - Representative CO and $PM_{2.5}$ Ambient Monitoring Data

	24-hr $PM_{2.5}$ µg/m3	Annual $PM_{2.5}$ µg/m3	CO-1hr ppm	CO 8-hr ppm
Tempe Station	18	8.9	2.2	1.6
Mesa Station	14	6.6	2.1	1.4
Scottsdale Station	NA	NA	2.8	1.4
NAAQS	35	12	10,000	40,000

The data from these three stations are very similar, indicating that the background air quality is relatively uniform in the area covered by these stations and surrounding the Ocotillo plant. In addition, the measured air quality is below the NAAQS limits, indicating that there are not existing adverse impacts for these two pollutants that trigger PSD review.

Demographics and Analysis of Project Air Quality Impact Locations

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 determined during the Census Bureau's American Community Survey 2008-2012. EJSCREEN has been used to identify potential EJ communities near the Ocotillo Power Plant.

Figure 1 presents the EJSCREEN Demographic Index map of the area within approximately 10 miles of the Ocotillo plant. EJSCREEN lists the Demographic Index by reporting the value as a percentile. A percentile in EJSCREEN tells us roughly what percent of the US population lives in a block group that has a lower value of the Demographic Index (in other words, as the percentile value increases, so does the percentage of low-income and minority populations in that census block). Locations at least at the 80th percentile but less than the 90th are shown in yellow on EJSCREEN maps, while those at the 90th percentile but less than 95th percentile are orange on the maps, and those at the 95th percentile or above are shown in red on maps. These color coded census blocks call attention to certain locations with higher percentages of low-income and minority populations.

The geographical distribution of Project's air quality impacts for the two criteria pollutants that trigger PSD review, CO and $PM_{2.5}$, have been plotted on a base map of the potential EJ communities near the Ocotillo Power Plant. Figures 2 and 3 present the EJSCREEN Demographic Index base map and plots of the Project air impacts. Figures 2 and 3 demonstrate that the Project impacts do not disproportionately occur in potential EJ community areas. For example, the distribution of the highest impacts is not disproportionately located at color coded census blocks but also occurs throughout non-color coded census blocks. The same is true for the Project 1-hr CO impact distributions. Again, it must be noted that because ALL impacts are in compliance with the NAAQS, it can be concluded that the Project will not result in disproportionately high and adverse human health or environmental effects on minority populations and low-income populations.

Appendix I - Environmental Justice Analysis for APS Ocotillo Modernization Project

Figure 1 – EJSCREEN Demographics Map in the Project Area

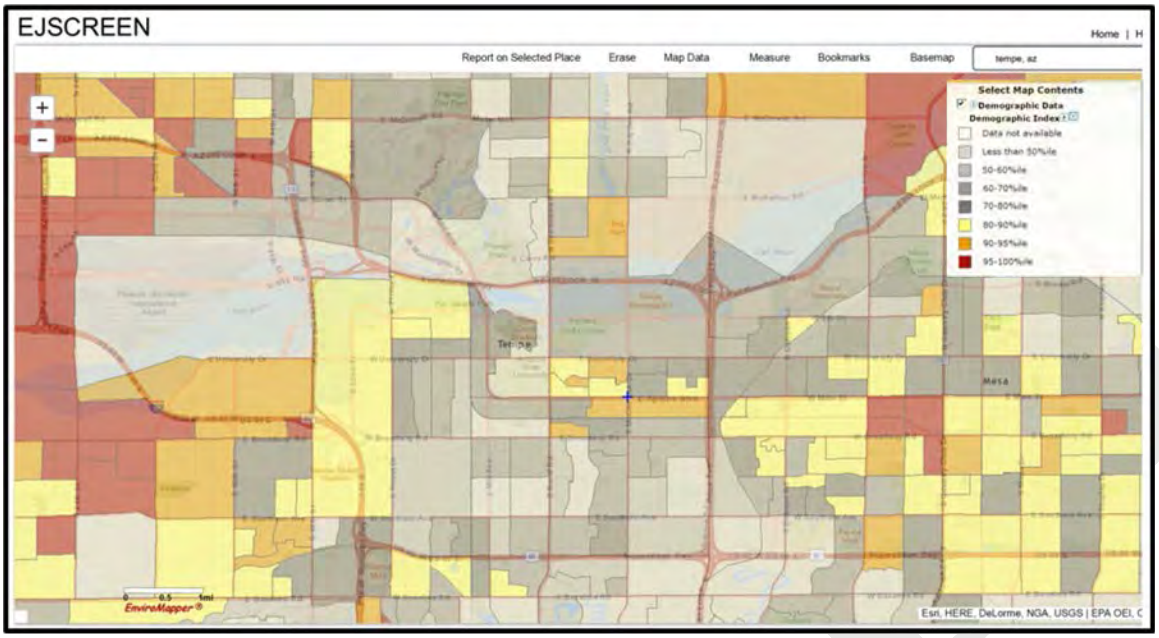


Figure 2 – Plot of Project 24-hr PM2.5 Impacts > 0.2 ug/m3

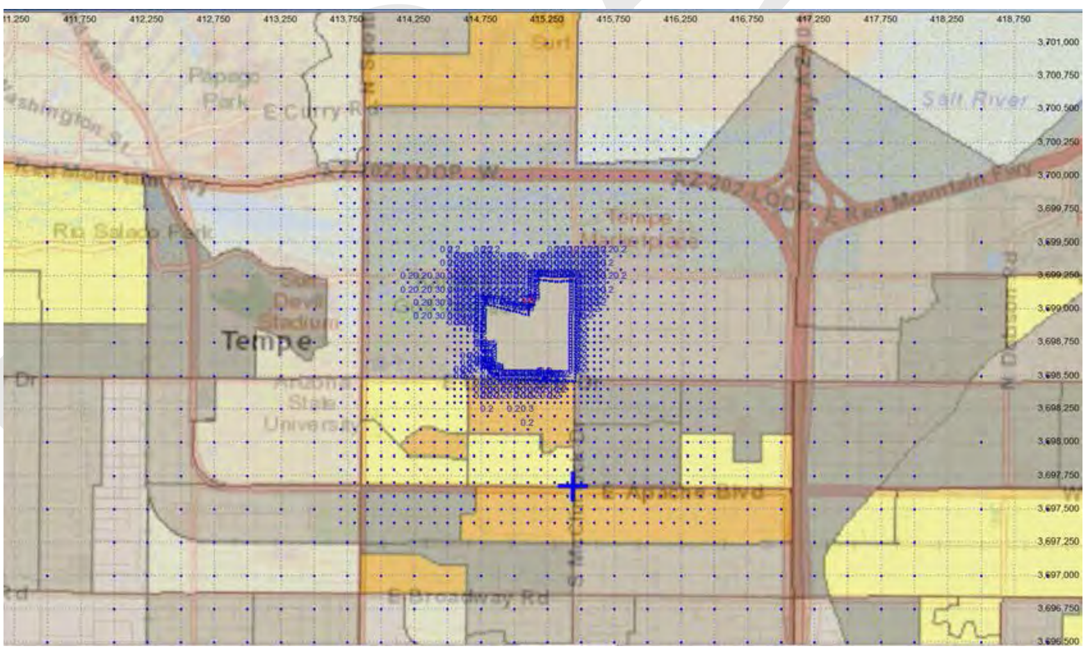
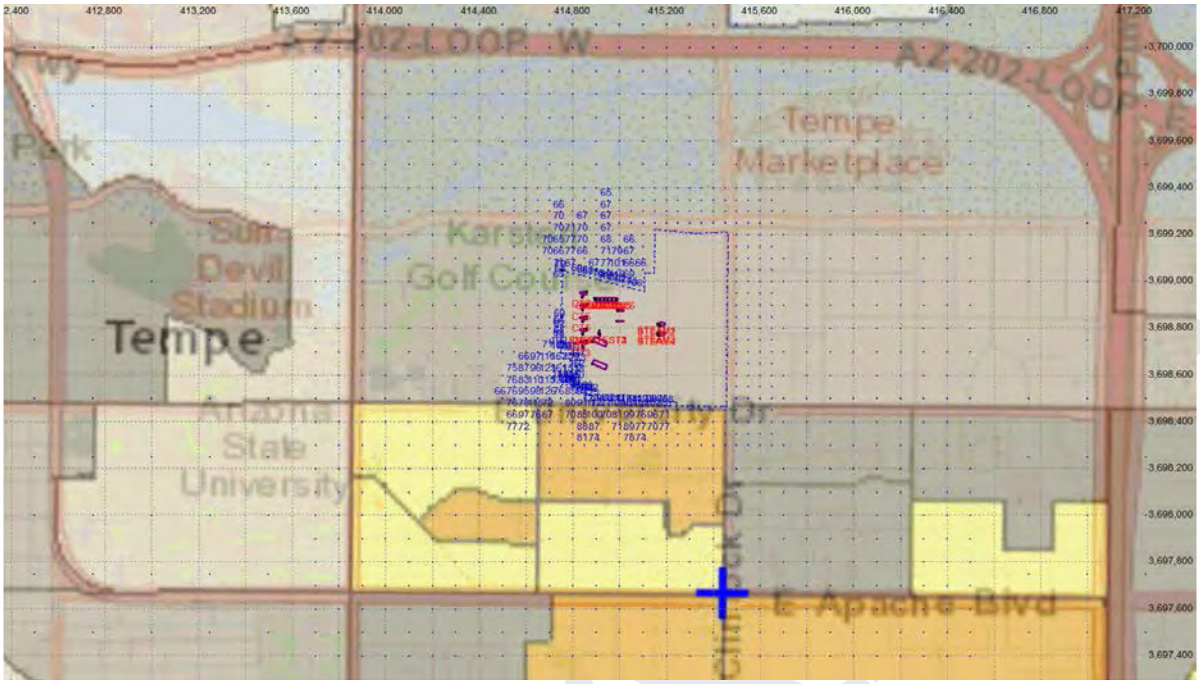


Figure 3 – Plot of Project 1-hr CO Impacts > 65 ug/m3



Public Participation/Outreach Activities

APS has developed a web page to present information, news updates, Frequency Asked Questions, a video presentation, a blog, and the ability to send comments on the Ocotillo Modernzation Project to all interested parties (http://www.azenergyfuture.com/ocotillo/). In addition, APS has advertised for the Project's open house (which was conducted in April 2014) in four different publications, including the Spanish newspaper Prensa Hispana, as well as the Arizona Republic, the East Valley Tribune and the ASU State Press. The advertisements for the project's CEC Line Siting Hearing (conducted in August 2014) were placed in the Arizona Republic and the East Valley Tribune.

Maricopa County is undertaking a number of actions to provide public participation opportunities to the community for its proposed PSD permit decision for the Project. The notice on the proposed permit and any public hearing is provided to the public through a wide variety of methods, including posting on the Maricopa County Air Quality Division Permit Reports website, and publication in the Record Reporter, Business Gazette, and Arizona Republic newspapers. In light of the Spanish-speaking population in the area, Maricopa County will provide sign language and/or Spanish interpreter upon request with 72 hours notice during any public hearing on the proposed permit. Additional reasonable accommodations will be made available to the extent possible within the time frame of the request. The permit application, proposed Technical Support Documentation, and proposed permit can also be reviewed online at the Maricopa County Air Quality Division website.

Conclusion

For purposes of an EJ analysis, EPA has recognized that compliance with the applicable NAAQS is indicative of achieving a level of public health protection that demonstrates that issuance of a PSD permit will not have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations. Because the Ocotillo Modernization Project air quality analysis has shown that the Project complies with the NAAQS for the pollutants that trigger PSD review, as well as other pollutants, the EJ 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.