Arizona Public Service Corporation
Saguaro Power Plant

Title V Permit Significant Revision Application for the Simple Cycle Combustion Turbine Expansion Project
Permit No. V20692.R01

Application to add two new natural gas-fired simple cycle combustion turbine electric generating units and make the Saguaro Power Plant a synthetic minor source under the Prevention of Significant Deterioration (PSD) program.

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Chapter 1. Executive Summary.

The Saguaro Power Plant is located in Section 15, Township 10S, Range 10E, Red Rock, Arizona. This location is designated as attainment or unclassifiable for all pollutants. This facility consists of three simple-cycle combustion turbines (CTs), three cooling towers, five fuel oil storage tanks, and an emergency diesel generator. Operating permit revision V20649.R01 removed the authority to operate two fossil fuel-fired steam electric generating units. With the removal of these units, the Saguaro Power Plant is not classified as a categorical source as defined in the Prevention of Significant Deterioration (PSD) program. Therefore, the major source threshold for the Saguaro Power Plant is 250 tons per year of any PSD regulated pollutant.

With this application, APS is proposing to construct and operate two new GE Vernova Model 7HA.02 natural gas-fired combustion turbine (CT) electric generating units. Each CT will be equipped with state-of-the-art air quality control systems including dry-low NO_x combustors and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control and oxidation catalysts for carbon monoxide (CO) and volatile organic compound (VOC) control. This project will also include a natural gas-fired natural gas heater, two mechanical draft cooling towers, and an emergency diesel fire pump.

As part of this application, APS is proposing to limit the total potential emissions for the entire facility, including the existing emissions units and the proposed new emissions units to less than 250 tons per year to make the Saguaro Power Plant a synthetic minor source under the PSD program. Please note that these limits will replace the current synthetic minor emission limits for the existing combustion turbine unit CT3.

This permit revision application includes a detailed description of the existing facility and the proposed Expansion Project. The potential emissions based on the proposed emissions and operating limits are calculated and compared to regulatory applicability thresholds. An analysis of other applicable regulations is also included in this application. New permit conditions are proposed, and a Compliance Certification is included. Finally, this application includes a detailed ambient air quality assessment which demonstrates that emissions from the source and the minor NSR modification will not interfere with attainment or maintenance of a national ambient air quality standard in any area.

Chapter 2. Existing Plant Description.

The existing Saguaro Power Plant consists of three (3) simple-cycle combustion turbines (CTs), three (3) cooling towers, five (5) fuel oil storage tanks, and an emergency diesel generator. The plant also includes other auxiliary equipment necessary to support and maintain the facility.

Combustion turbine units CT1 and CT2 are Westinghouse Model 501AA natural gas-fired simple cycle CTs. Each unit is nominally rated at 55 megawatts (MW) of electric output. These CTs also have the ability to be peak-fired which increases the electric output to 67 MW. Potential emissions for each CT are detailed in Table 2-1. APS had previously planned to install inlet fogging with overspray systems on these two units but has not done so to date. The current permit includes the authorization and operational requirements to install these systems, and APS may install these systems in the future.

CT3 is a General Electric Model 7EA natural gas-fired simple cycle CT with a nominal rating of 80 MW which was installed in 2002. CT3 is equipped with dry-low NO_x (DLN) combustion systems and is subject to the *Standards of Performance for Stationary Gas Turbines*, 40 CFR 60 Subpart GG. CT3 is also an affected unit under the Acid Rain Program and is equipped with a NO_x continuous emissions monitoring system (NO_x CEMS). CT3 is subject to PSD synthetic minor emission limits of 39 tons per year for NO_x emissions and 97.5 tons per year for CO emissions. CT3 is equipped with NO_x and CO CEMS and utilizes these CEMS to demonstrate compliance with the CO and NO_x emission limits.

The facility also includes a 500 kW(e), 755 horsepower emergency diesel generator which is located at the Battery Energy Storage System (BESS) associated with the adjacent solar energy facility. Potential emissions for this generator based on 500 hours per year of operation and the applicable Tier 2 standards are included in Table 2-3.

The facility has three (3) mechanical draft cooling towers which are used for cooling of the combustion turbine lubricating oil and the CT electric generator. Potential PM, PM10, and PM2.5 emissions for these cooling towers are summarized in Tables 2-4 and 2-5 and are based on the method described in section 4.3 of this application. Finally, the facility has five (5) fuel oil storage tanks with a combined storage capacity of approximately 16.2 million gallons. However, Operating Permit Revision V20649.R01 removed the authority to operate the 2 steam-electric units and removed the authority to burn fuel oil as an alternative operating scenario at the plant.

The total unrestricted potential emissions for the existing Saguaro Power Plant as detailed above are summarized in Table 2-6. Table 2-7 is a summary of the past actual annual emissions for the combustion turbine units CT1, CT2, and CT3 for the past 5 years. Table 2-7 demonstrates that the actual emissions for the existing facility are well below the major source threshold level.

TABLE 2-1. Potential emissions for each combustion turbine unit CT1 and CT2.

POLLUTANT		Heat Input	Emission Factor		Potential Emissions	
		mmBtu/hr	lb / mmBtu	lb / 10^6 CF	lb / hr	ton / yr
Carbon Monoxide	CO	939	0.082	82.0	77.0	337.3
Nitrogen Oxides	NO_x	939	0.320	320.0	300.5	1,316.1
Particulate Matter	PM	939	0.0066	6.6	6.2	27.1
Particulate Matter	PM_{10}	939	0.0066	6.6	6.2	27.1
Particulate Matter	$PM_{2.5}$	939	0.0066	6.6	6.2	27.1
Sulfur Dioxide	SO_2	939	0.0006	0.6	0.56	2.5
Vol. Org. Cmpds	VOC	939	0.0021	2.1	1.97	8.6
Sulfuric Acid Mist	H_2SO_4	939	0.00015	0.15	0.14	0.6
Fluorides	F	939			0.00	0.00
Lead	Pb	939	4.9E-07	0.0005	0.0005	0.002
Carbon Dioxide	CO_2	939	117.0	119,900	109,841	481,102
Greenhouse Gases	CO_2e	939	117.1	120,024	109,953	481,596

TABLE 2-2. Potential emissions for combustion turbine unit CT3.

POLLUTANT		Heat Input	Emission Factor		Potential Emissions	
		mmBtu/hr	lb / mmBtu	lb / 10^6 CF	lb / hr	ton / yr
Carbon Monoxide	CO	933	0.056	56.0	52.2	97.5
Nitrogen Oxides	NO_x	933	0.276	276.3	257.8	39.0
Particulate Matter	PM	933	0.0066	6.6	6.2	27.0
Particulate Matter	PM_{10}	933	0.0066	6.6	6.2	27.0
Particulate Matter	$PM_{2.5}$	933	0.0066	6.6	6.2	27.0
Sulfur Dioxide	SO_2	933	0.0006	0.6	0.56	2.5
Vol. Org. Cmpds	VOC	933	0.0021	2.1	1.96	8.6
Sulfuric Acid Mist	H_2SO_4	933	0.00015	0.15	0.14	0.6
Fluorides	F	933			0.00	0.00
Lead	Pb	933	4.9E-07	0.0005	0.0005	0.002
Carbon Dioxide	CO_2	933	117.0	119,900	109,139	478,027
Greenhouse Gases	CO_2e	933	117.1	120,024	109,251	478,518

Footnotes

1. Potential emissions are based on 8,760 hours per year of operation at the maximum rated heat input for each CT.
2. The emission factors for CO, NO_x, PM, PM_{10}, $PM_{2.5}$, and VOC emissions are for uncontrolled natural gas-fired CTs from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, 5th Ed., Table 3.1-1 and 3.1-2a.
3. For CT3, NOx emissions are based on the standard under 40 CFR 60 Subpart GG of 75 ppmdv at 15% O_2. Potential NOx emissions are based on the limit of 39 tons per year.
3. SO_2 emissions are based on pipeline natural gas with an SO_2 emission rate of 0.0006 lb/mmBtu.
4. Sulfuric acid mist emissions are based on a worse-case conversion of SO_2 sulfuric acid mist of 25% by weight.
5. The emission factors for greenhouse gases including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

TABLE 2-3. Potential emissions for the 500 kW diesel emergency generator.

Pollutant		Heat Input	Power Out	Emission Factor		Potential Emissions	
		mmBtu/hr	hp	lb/mmBtu	g/hp-hr	lb/hr	ton/year
Carbon Monoxide	CO	8.0	755	0.543	2.6	4.34	1.09
Nitrogen Oxides	NO_x	8.0	755	0.992	4.8	7.94	1.98
Particulate Matter	PM	8.0	755	0.031	0.15	0.25	0.06
Particulate Matter	PM_{10}	8.0	755	0.031	0.15	0.25	0.06
Particulate Matter	$PM_{2.5}$	8.0	755	0.031	0.15	0.25	0.06
Sulfur Dioxide	SO_2	8.0	755	0.0015		0.012	0.003
Vol. Org. Cmpds	VOC	8.0	755	0.99	4.8	7.94	1.98
Sulfuric Acid Mist	H_2SO_4	8.0	755	0.00038		0.003	0.0008
Fluorides (as HF)	F	8.0	755	0.0373		0.30	0.07
Lead	Pb	8.0	755	0.000009		0.00007	0.00002
Carbon Dioxide	CO_2	8.0	755	163.1		1,304.4	326.1
Greenhouse Gases	CO_2e	8.0	755	163.6		1,308.7	327.2

Footnotes

1. Potential emissions are based on 500 hours per year of operation at the maximum rated engine power output.
2. CO, NO_x, PM, and VOC emissions are based on the applicable Tier 2 emission standards in 40 CFR Part 1039, Appendix I, Table 2. The Tier 2 standards include a combined NO_x + HC standard of 6.4 g/kW-hr (4.8 g/hp-hr). As a worst-case analysis, potential NO_x and VOC emissions are based on the standard for both pollutants.
3. The SO_2 emission factor is based on the ultra-low sulfur fuel standards for diesel of 15 ppm of sulfur. Based on a low sulfur diesel heat value of 19,594 Btu/lb, this is equal to an SO_2 emission rate of 0.0015 lb/mmBtu.
4. The lead (Pb) and fluorides emission factors are based on combustion of fuel oil from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, 5th Edition, Table 1.3-10 and 1.3-11.

TABLE 2-4. Potential emissions for each of the CT1 and CT2 cooling towers.

POLLUTANT		*Q* Flowrate	C_{TDS} TDS Conc.	%DL Drift Loss	*k* Particle Size Multiplier	Potential Emissions	
		gal/min	ppm	%		lb/hr	ton/yr
Particulate Matter	PM	500	2,450	0.005%	1.00	0.031	0.13
Particulate Matter	PM_{10}	500	2,450	0.005%	0.705	0.022	0.095
Particulate Matter	$PM_{2.5}$	500	2,450	0.005%	0.0023	0.00007	0.0003

TABLE 2-5. Potential emissions for the CT3 cooling tower.

POLLUTANT		*Q* Flowrate	C_{TDS} TDS Conc.	%DL Drift Loss	*k* Particle Size Multiplier	Potential Emissions	
		gal/min	ppm	%		lb/hr	ton/yr
Particulate Matter	PM	3,100	2,450	0.005%	1.00	0.19	0.83
Particulate Matter	PM_{10}	3,100	2,450	0.005%	0.705	0.13	0.59
Particulate Matter	$PM_{2.5}$	3,100	2,450	0.005%	0.0023	0.00043	0.0019

TABLE 2-6. Unrestricted potential emissions for the existing Saguaro Power Plant emissions units.

Pollutant		Simple Cycle CTs			Mechanical Cooling Towers			Emergency Generator	TOTAL
		CT1	CT2	CT3	MCT1	MCT2	MCT3		
Carbon Monoxide	CO	337.3	337.3	97.5				1.1	773.1
Nitrogen Oxides	NO_x	1,316.1	1,316.1	39.0				2.0	2,673.2
Particulate Matter	PM	27.1	27.1	27.0	0.13	0.13	0.83	0.1	82.4
Particulate Matter	PM_{10}	27.1	27.1	27.0	0.095	0.095	0.59	0.1	82.1
Particulate Matter	$PM_{2.5}$	27.1	27.1	27.0	0.0003	0.0003	0.0019	0.1	81.3
Sulfur Dioxide	SO_2	2.5	2.5	2.5				0.0	7.4
Vol. Org. Cmpds	VOC	8.6	8.6	8.6				2.0	27.8
Sulfuric Acid Mist	H_2SO_4	0.6	0.6	0.6				0.00	1.85
Fluorides (F)	F	0.0	0	0				0.0746	0.0746
Lead	Pb	0.002	0.002	0.002				0.0000	0.0060
Carbon Dioxide	CO_2	481,102	481,102	478,027				326.1	1,440,557
Greenhouse Gases	CO_2e	481,596	481,596	478,518				327.2	1,442,037

TABLE 2-7. Actual annual emissions for the existing CTs at Saguaro Power Plant, ton/yr.

Pollutant		Unit	2021	2022	2023	2024	2025
Carbon Monoxide	CO	CT1	5.6	7.7	15.9	8.7	4.2
		CT2	4.5	7.3	15.5	9.7	4.3
		CT3	15.2	11.4	19.3	14.5	15.8
		TOTAL	**25.2**	**26.5**	**50.7**	**32.9**	**24.4**
Nitrogen Oxides	NO_x	CT1	21.7	30.2	62.2	34.1	16.6
		CT2	17.4	28.5	60.5	37.7	16.9
		CT3	17.3	14.9	24.4	35.7	25.0
		TOTAL	**56.5**	**73.6**	**147.1**	**107.5**	**58.4**
Particulate Matter	PM_{10}, $PM_{2.5}$	CT1	0.4	0.6	1.3	0.7	0.3
		CT2	0.4	0.6	1.2	0.8	0.3
		CT3	3.0	2.7	5.3	4.5	4.4
		TOTAL	**3.8**	**3.9**	**7.8**	**6.0**	**5.1**
Sulfur Dioxide	SO_2	CT1	0.04	0.06	0.12	0.06	0.03
		CT2	0.03	0.05	0.11	0.07	0.03
		CT3	0.27	0.25	0.48	0.41	0.40
		TOTAL	**0.3**	**0.4**	**0.7**	**0.5**	**0.5**
Vol. Organic Compounds	VOC	CT1	0.1	0.2	0.4	0.2	0.1
		CT2	0.1	0.2	0.4	0.2	0.1
		CT3	1.0	0.9	1.7	1.4	1.4
		TOTAL	**1.2**	**1.2**	**2.5**	**1.9**	**1.6**

Chapter 3. Simple Cycle CT Expansion Project.

With this application, APS is proposing to construct and operate two (2) new GE Vernova Model 7HA.02 natural gas-fired combustion turbine (CT) electric generating units. Each simple cycle CT will have a maximum nominal heat input capacity of 3,279 mmBtu per hour and a maximum nominal electric output of 359 MW each. Each CT will be equipped with state-of-the-art air quality control systems including dry-low NO_x combustors and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control and oxidation catalysts for carbon monoxide (CO) and volatile organic compound (VOC) control. This project will also include a natural gas-fired natural gas conditioning or dew point heater, two (2) mechanical draft cooling towers, and an emergency fire pump. Other equipment will include natural gas piping systems and sulfur hexafluoride (SF_6) insulated high voltage circuit breakers.

The site layout for the Saguaro Power Plant and the proposed new CTs is shown in Figure 3-1.

3.1 GE Vernova Model 7HA.02 Simple Cycle CTs.

The proposed GE Vernova Model 7HA.02 natural gas-fired CTs are heavy-duty, H-class CTs that utilize advanced technology to provide flexible, efficient electric power generation. A CT is an internal combustion engine which uses inlet air as the working fluid to produce mechanical power. A CT is comprised of an air inlet system, a turbine compressor section, a combustion section, and a power turbine section. The air inlet system supplies air to the multistage axial compressor and will include an inlet air cooler, air filters, and a noise silencer. During operation, ambient air is drawn into the compressor section, compressed, and then heated by the combustion of natural gas in the combustion section. The combustion gases then expand through the power turbine section of the CT. This expansion rotates the shaft of the turbine and the coupled electric generator which produces electric power.

The general specifications for the proposed GE Vernova 7HA.02 CTs are summarized in Table 3-1. Figure 3-2 shows the GE Vernova 7HA.02 heavy duty class of turbines, the dry low NO_x combustors and the compressor and power sections (from GE Vernova). Figure 3-3 is a general schematic diagram of a simple cycle combustion turbine electric generating unit.

When operated as simple-cycle CTs, the units will use the mechanical energy generated by the CT to power an electric generator. In a simple-cycle CT, the hot exhaust gases are emitted directly to the selective catalytic reduction (SCR) and oxidation catalyst air quality control systems and then to the atmosphere.

Each CT will be equipped with inlet air filters which remove dust and particulate matter from the inlet air. During hot weather, the filtered air may also be cooled by passing the air through an evaporative cooling system. During cold weather, the filtered air may be heated using a radiative heating system that is part of the anti-icing system. This system utilizes glycol and water solution as the working fluid that is heated by induction heaters. The filtered and conditioned air is then drawn into the low-pressure compressor section where the air is compressed.

The CTs will be enclosed in a metal acoustic enclosure which also contains auxiliary equipment. Each combustion turbine package may be equipped with the following equipment/components:

- Inlet air filters
- Inlet evaporative cooling system
- Anti-icing system
- Lube oil system
- Duplex shell and tube lube oil coolers for the combustion turbine and generator
- Dry low NO_x (DLN) combustor air quality control system
- Selective Catalytic Reduction (SCR) air quality control system and ammonia injection system
- Oxidation catalyst air quality control system
- Fire detection and protection system
- Hydraulic starting system
- Compressor variable bleed valve vent to prevent compressor surge in off-design operation.

TABLE 3-1. General Specifications for the GE Vernova Model 7HA.02 CTs.

Parameter	Value
Manufacturer	GE Vernova
Model	7HA.02
Type	Heavy Duty CT
Maximum Electric Power Rating, MW gross (each CT)	359
Maximum Full Load Heat Input, mmBtu/hr (each CT)	3,279
Full Load Heat Rate, gross (based on HHV at 73 F), Btu/kWh	9,170
Manufacturer's Design Efficiency, (based on HHV at 73 F)	37.2%

FIGURE 3-1. Site layout plan for the Saguaro Power Plant showing the existing power plant and the layout of the proposed new CTs.

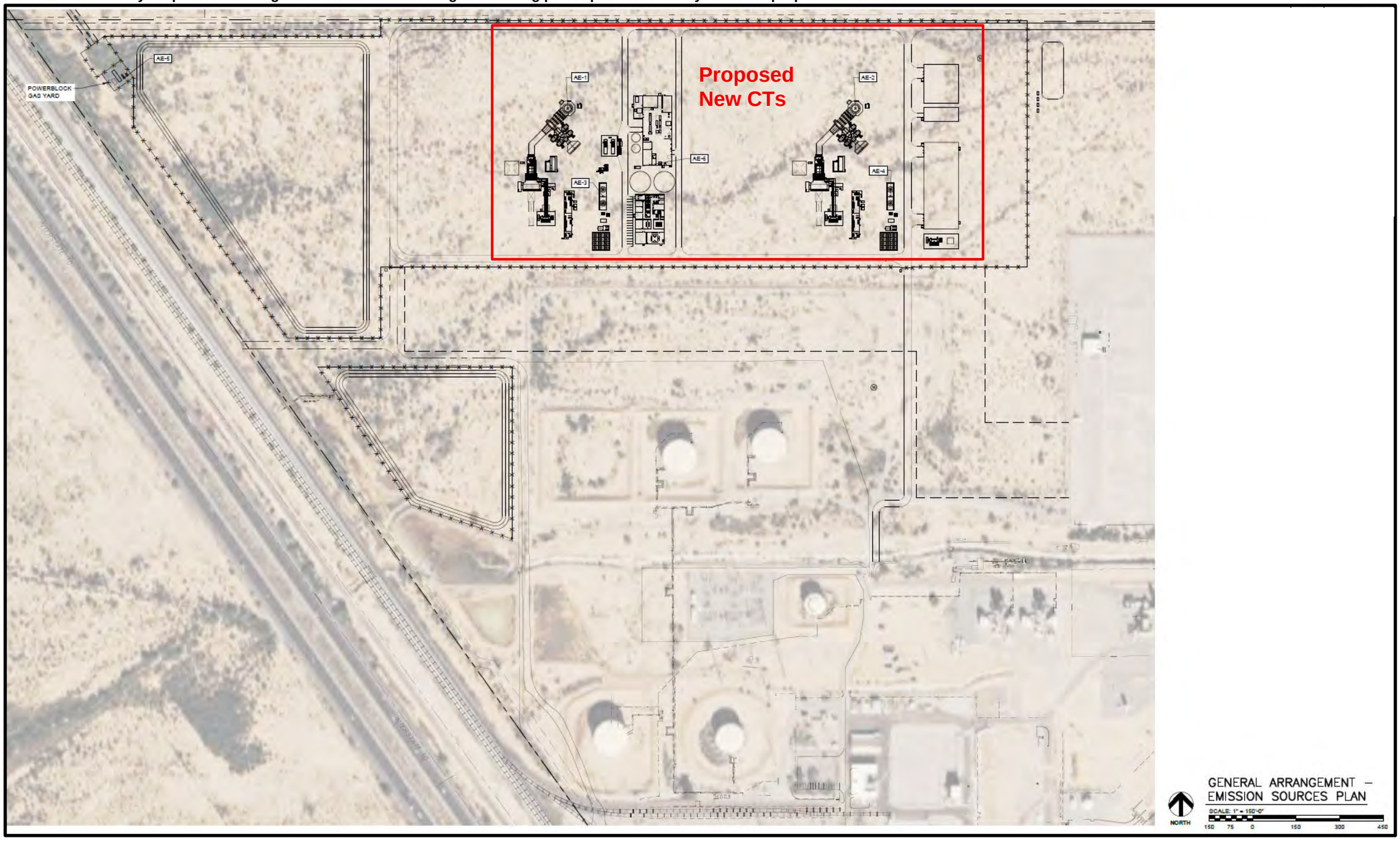


FIGURE 3-2. Image of the 7HA class heavy duty CT showing the dry low NOx combustors and compressor and power sections (from GE Vernova).



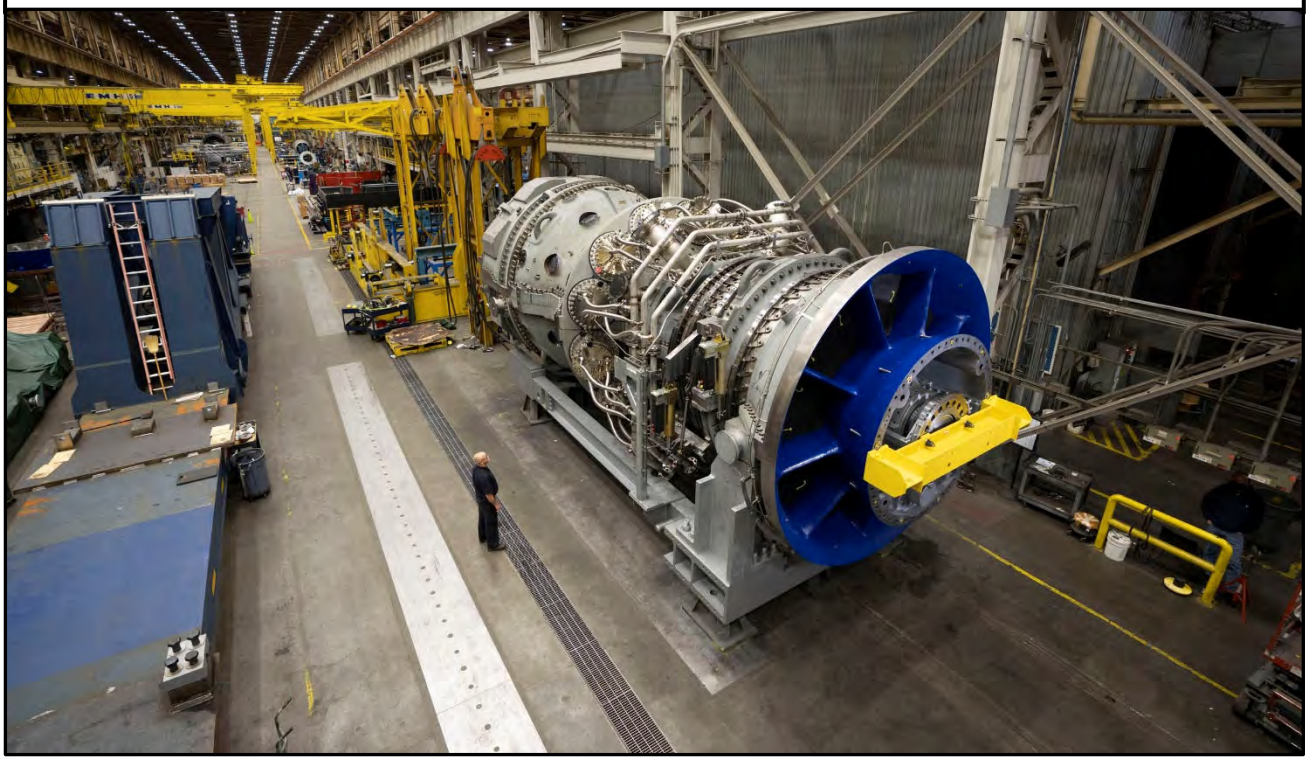
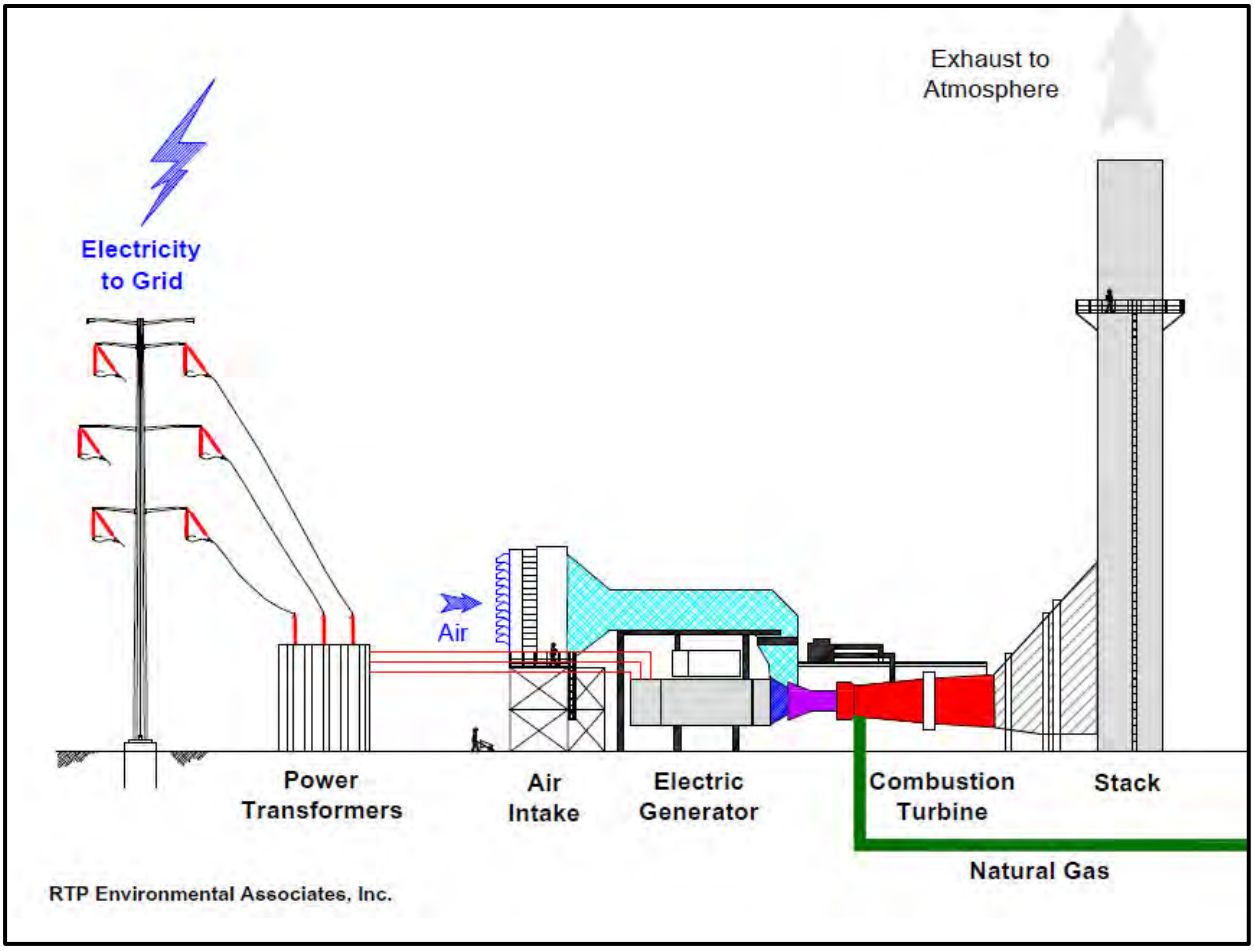


FIGURE 3-3. Schematic diagram of a simple cycle combustion turbine generating unit.



3.1.1 Air Quality Control Systems

Each of the proposed CTs will be equipped with state-of-the-art dry low NO_x combustion systems which will optimize combustion. The combustion gases will exit each CT at approximately 700 to 1,100 ºF. For these simple cycle CT units, the exhaust gases will then pass through an oxidation catalyst system for the control of CO and VOC emissions, and a selective catalytic reduction (SCR) system for the control of NO_x emissions.

3.1.2 Dry Low NO_x (DLN) Combustion Systems

Each CT will be equipped with state-of-the-art dry low NO_x (DLN) combustion systems. DLN utilizes a lean premixed combustion process in which fuel and air are premixed before entering the CT, allowing for more efficient burning, lower combustion temperatures, and lower CO, NO_x, and VOC emissions.GE Vernova's DLN family (DLN 2/2.6/2.6+/2.6e) of combustion systems enables GE Vernova's H-class gas turbines to reduce NO_x emissions while enabling high plant efficiency and extending outage intervals. The DLN 2.6e maintains many of the elements of GE Vernova's DLN 2.6+ combustion system but introduces advanced premixing to the 7HA gas turbine combustor.

3.1.3 Selective Catalytic Reduction (SCR).

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

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

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

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

3.1.4 Oxidation Catalyst System.

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

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

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

3.2 Balance of Plant Emissions Units.

The Simple Cycle CT Expansion Project will include several other significant emissions units, including:

1. One (1) natural gas-fired natural gas heater.
2. Two (2) counter flow, mechanical draft cooling towers.
3. One (1) 510 horsepower diesel engine driven fire pump.

Chapter 4. CT Expansion Project Emissions Analysis.

4.1 Simple Cycle CT Units CT4 and CT5.

Potential emissions for the new GE Vernova 7HA.02 simple cycle CTs are based on the use of DLN combustion and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control and oxidation catalysts for CO, VOC, and organic HAP control. This emissions analysis is also based on the proposed emission limits in this application. Greenhouse gas emissions are provided for informational purposes. As discussed in Section 6.1.1, GHGs are not a PSD regulated pollutant for the Saguaro Power Plant.

4.1.1 Normal Operation.

The maximum regulated NSR pollutant emission rates for each 7HA.02 simple cycle CT during normal operation and with controls are summarized in Table 4-1.

4.1.2 Startup and Shutdown Emissions.

The CT air pollution control systems including the SCR and oxidation catalyst systems are not operational during periods of startup and shutdown (SU/SD) because the exhaust gas temperatures are too low for these systems to function as designed. In addition, the DLN combustors cannot operate in the full premix mode until sufficient flue flow is delivered to allow for full fuel and air premixing. As a result, CO, NO_x, and VOC emissions may be elevated during periods of startup and shutdown.

Table 4-2 is a summary of the startup and shutdown duration, the expected fuel consumption, expressed as mmBtu, and the PSD regulated air pollutant emissions. Note that the startup and shutdown durations, heat input, and emissions, expressed in pounds per event, are the maximum expected values. Under normal conditions, these CTs can startup in simple cycle mode in approximately 30 minutes which will generally result in lower heat input and lower mass emissions. Furthermore, the emission rates for PM, PM_{10}, and $PM_{2.5}$ emissions, as well as SO_2, sulfuric acid mist, lead (Pb), CO_2, and GHG emissions, expressed in pounds per million Btu of heat input (lb/mmBtu), are NOT elevated during periods of startup and shutdown. Therefore, the highest mass emission rate for these pollutants, expressed in pounds per hour, occurs during normal operation at 100% of the rated capacity of the CTs. Further, the total mass emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, sulfuric acid mist, lead (Pb), CO_2, and GHG emissions, expressed in tons per year, can be accumulated based only on heat input and the respective pollutant emission rate, expressed in lb/mmBtu.

4.1.3 Total Potential Emissions for Each Simple Cycle CT.

Table 4-3 is a summary of the total potential emissions for each CT based on the proposed emission limits and operational limits detailed in Chapter 4 of this application. Please note that the total potential emissions are based on limiting startup and shutdown events to 365 events per 12-month period, and limiting the capacity factor of each CT to no more than 45%.

TABLE 4-1. Maximum potential emission rates with controls for each GE 7HA.02 simple cycle CT during normal operation.

Pollutant		Heat Input	Emission Rate		
		mmBtu/hr	lb/mmBtu	ppm @ 15% O_2	lb/hr
Carbon Monoxide	CO	3,279	0.0202	9.0	66.2
Nitrogen Oxides	NO_x	3,279	0.0332	9.0	108.9
Particulate Matter	PM	3,279	0.0076		25.0
Particulate Matter	PM_{10}	3,279	0.0076		25.0
Particulate Matter	$PM_{2.5}$	3,279	0.0076		25.0
Sulfur Dioxide	SO_2	3,279	0.0006		2.0
Vol. Org. Compounds	VOC	3,279	0.0026	2.0	8.4
Sulfuric Acid Mist	H_2SO_4	3,279	0.00015		0.49
Fluorides (F)	F	3,279	0.00000		0.0000
Lead	Pb	3,279	0.0000005		0.0016
Carbon Dioxide	CO_2	3,279	117.0		383,532
Greenhouse Gases	CO_2e	3,279	117.1		383,926

Footnotes

1. CO and NO_x emissions during normal operation are calculated based on concentrations of 9 and 9 parts per million, dry volume basis (ppmdv) corrected to 15% excess oxygen according to the following equations from 40 CFR Part 60, Appendix A, Reference Method 19, Eq. 19-1 and 40 CFR Part 75, Appendix F, Eq. F-5:

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

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

2. PM emissions are based on a proposed emission limit of 25.0 pounds per hour.
3. All filterable plus condensable PM_{10} emissions are also assumed to be $PM_{2.5}$ emissions.
4. Sulfur dioxide (SO_2) emissions are based on the emission factor for the combustion of pipeline natural gas from the Acid Rain Program in 40 CFR Part 75 of 0.0006 lb SO_2/mmBtu.
5. VOC emissions are based on a proposed emission limit of 8.4 pounds per hour.
6. Lead (Pb) emissions are based on the emission factor from the U.S. EPA's *AP-42*, Table 1.4-2.
7. The emission factors for greenhouse gases including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

TABLE 4-2. Maximum emission rates for each GE 7HA.02 simple cycle CT during startup and shutdown.

Pollutant		Startup			Shutdown			TOTAL SU/SD EMISSIONS	
		Duration	Heat Input	Emissions	Duration	Heat Input	Emissions		
		minutes	mmBtu	lb	minutes	mmBtu	lb	lb / mmBtu	lb / event
Carbon Monoxide	CO	30	825	127.0	12	182	116.3	0.242	243.3
Nitrogen Oxides	NO_x	30	825	13.2	12	182	12.3	0.025	25.5
Particulate Matter	PM	30	825	6.3	12	182	1.4	0.008	7.7
Particulate Matter	PM_{10}	30	825	6.3	12	182	1.4	0.008	7.7
Particulate Matter	$PM_{2.5}$	30	825	6.3	12	182	1.4	0.008	7.7
Sulfur Dioxide	SO_2	30	825	0.50	12	182	0.11	0.0006	0.6
Vol. Org. Cmpds	VOC	30	825	37.6	12	182	36.1	0.073	73.7
Sulfuric Acid Mist	H_2SO_4	30	825	0.25	12	182	0.05	0.000	0.3
Fluorides (F)	F	30	825	0.00000	12	182	0.0000	0.000	0.0
Lead	Pb	30	825	0.00041	12	182	0.0001	0.000	0.0
Carbon Dioxide	CO_2	30	825	96,505	12	182	21,290	117.0	117,795
Greenhouse Gases	CO_2e	30	825	96,604	12	182	21,312	117.1	117,916

TABLE 4-3. Potential emissions for each new GE 7HA.02 simple cycle CT.

Pollutant		Heat Input	Normal Operation					Startup / Shutdown			TOTAL
		mmBtu/hr	lb/mmBtu	ppm @ 15% O_2	lb/hr	mmBtu/yr	ton/yr	lb/event	event/yr	ton/yr	ton/year
Carbon Monoxide	CO	3,279	0.0202	9.0	66.2	12,924,700	130.5	243.3	365	44.4	174.9
Nitrogen Oxides	NO_x	3,279	0.0332	9.0	108.9	12,924,700	214.6	25.5	365	4.7	219.2
Particulate Matter	PM	3,279	0.0076		25.0	12,924,700	49.3	7.68	365	1.40	49.3
Particulate Matter	PM_{10}	3,279	0.0076		25.0	12,924,700	49.3	7.68	365	1.40	49.3
Particulate Matter	$PM_{2.5}$	3,279	0.0076		25.0	12,924,700	49.3	7.68	365	1.40	49.3
Sulfur Dioxide	SO_2	3,279	0.0006		2.0	12,924,700	3.88	0.60	365	0.11	3.9
Vol. Org. Cmpds	VOC	3,279	0.0026	2.0	8.4	12,924,700	16.6	73.7	365	13.5	30.0
Sulfuric Acid Mist	H_2SO_4	3,279	0.00015		0.5	12,924,700	0.97	0.30	365	0.1	1.0
Fluorides (F)	F	3,279	0.00000		0.000	12,924,700	0.0000	0.0000	365	0.0000	0.000
Lead	Pb	3,279	0.0000005		0.00164	12,924,700	0.0032	0.0005	365	0.0001	0.003
Carbon Dioxide	CO_2	3,279	117.0		383,532	12,924,700	755,940	117,795	365	21,498	755,940
Greenhouse Gases	CO_2e	3,279	117.1		383,926	12,924,700	756,717	117,916	365	21,520	756,717

Footnotes

1. Potential hourly emissions are based on the maximum heat input to the CTs of 3,279 mmBtu per hour.
2. Potential annual emissions are based on an annual capacity factor of 45%, expressed as a heat input limit of 11,488,600 mmBtu per 12-month period.
3. CO and NO_x emissions during normal operation are calculated based on concentrations of 9 ppmdv at 15% O_2 for each pollutant.
4. PM emissions are based on a proposed emission rate of 25 pounds per hour. All PM emissions are also assumed to be PM_{10} and $PM_{2.5}$ emissions.
5. SO_2 emissions are based on the emission factor for pipeline natural gas from the Acid Rain Program in 40 CFR Part 75 of 0.0006 lb SO_2/mmBtu.
6. VOC emissions are based on a proposed emission rate of 8.4 pounds per hour, expressed as methane (CH_4).
7. Sulfuric acid mist emissions are based on a 25% conversion of SO_2 to sulfuric acid on a mass basis.
8. Lead (Pb) emissions are based on the emission factor from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42,* 5th Edition, Table 1.4-2.
9. The emission factors for greenhouse gases including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

4.2 Natural Gas-Fired Natural Gas Heater.

The natural gas used for the Saguaro Power Plant will be supplied from a high-pressure natural gas transmission line. The natural gas pressure must be reduced from the transmission pressures for use in the CTs. When the gas pressure is reduced, the gas experiences adiabatic cooling which can cause condensation of natural gas components and fuel handling problems. To ensure that this does not happen, the project will include a natural gas-fired natural gas heater with a maximum rated heat input capacity of 35 mmBtu per hour. Table 4-4 summarizes the potential emissions for each natural gas-fired natural gas heater based on 8,760 hours per year of operation and the BACT limits in this application.

TABLE 4-4. Potential emissions for the natural gas-fired natural gas heater.

Pollutant		Emission Factor		Heat Input	Potential to Emit	
		lb/mmcf	lb/mmBtu	mmBtu/hr	lb/hr	ton/year
Carbon Monoxide	CO	40.0	0.040	35.0	1.40	6.13
Nitrogen Oxides	NO_x	37.0	0.037	35.0	1.30	5.67
Particulate Matter	PM	5.0	0.005	35.0	0.18	0.77
Particulate Matter	PM_{10}	5.0	0.005	35.0	0.18	0.77
Particulate Matter	$PM_{2.5}$	5.0	0.005	35.0	0.18	0.77
Sulfur Dioxide	SO_2	0.6	0.0006	35.0	0.0210	0.092
Vol. Org. Cmpds	VOC	5.5	0.0055	35.0	0.193	0.84
Sulfuric Acid Mist	H_2SO_4		0.00006	35.0	0.0021	0.0092
Fluorides	F			35.0	0.000000	0.00
Lead	Pb	0.0005	0.0000005	35.0	0.000018	0.00008
Carbon Dioxide	CO_2	116,976	117.0	35.0	4,094.2	17,932.4
Greenhouse Gases	CO_2e	117,097	117.1	35.0	4,098.4	17,950.9

Footnotes

1. Potential emissions are based on 8,760 hours per year of operation.

2. CO and NO_x emissions are based on concentrations of 50 and 30 ppmdv at 3% O_2, respectively.

3. Emission factors for uncontrolled SO_2, and lead (Pb) emissions are for uncontrolled natural gas-fired boilers from the U.S. EPA document *AP-42, Compilation of Air Pollutant Emission Factors*, 5th Edition, section 1.4, Table 1.4-1. The emission rate in pounds per million cubic feet of gas (lb/mmcf) was converted to pounds per million Btu based on a natural gas heat content of 1,000 mmBtu per mmcf.

4. Emission factors for uncontrolled PM, PM_{10} and $PM_{2.5}$ are as stated by the manufacturer.

5. Sulfuric acid mist emissions are based on 10% conversion of SO_2 to SO_3.

6. Natural gas does not contain significant amounts of fluorine. Therefore, fluoride emissions are expected to be insignificant.

7. Greenhouse gas (GHG) emissions are based on the emission factors for 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.

4.3 Mechanical Draft Cooling Towers.

Each new CT will be equipped with a cooling tower which will be used to cool lubricating oil and the unit's electric generator. The new wet cooling towers will be counter flow, mechanical draft cooling towers. The specifications for each cooling tower are summarized in Table 4-5.

TABLE 4-5. Specifications for the new mechanical draft cooling tower.

Total Circulating Water Flow, gallons per minute	2,500
Number of Cells	2
Maximum Total Dissolved Solids, ppm	2,450
Design Drift Loss, %	0.005%
Release Height, feet	20
Exit Diameter per cell, feet	6.5
Volumetric Air Flow of each Cell, acfm	64,000
Normal Discharge Temperature, ^{o}F	105

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, a fan induces an air flow in a countercurrent direction. A portion of the circulating water evaporates, cooling the remaining water. A much smaller amount of the water may be entrained in the induced air flow in the form of liquid phase droplets or mist called *drift*. 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.

Drift eliminators are used at the outlet of cooling towers to reduce the amount of water droplets entrained in the exhaust air. Drift eliminators are typically blades configured in a chevron pattern which cause the water droplets to impact these blades and fall back into the tower. The mist eliminators will be designed to reduce the drift loss to 0.001% of the circulating water flow.

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

$$E = kQ\left(\frac{60\ \text{min}}{\text{hour}}\right)\left(\frac{8.345\ \text{lb water}}{\text{gal water}}\right)\left(\frac{C_{TDS}}{10^6}\right)\left(\frac{\%DL}{100}\right)$$

Where,

E	=	Particulate matter emissions, pounds per hour, lb/hr	
Q	=	Circulating water flow rate, gallons per minute	= 2,500 gpm
C_{TDS}	=	Circulating water total dissolved solids, parts per million	= 2,450 ppm
%DL	=	Drift loss, %	= 0.001%
k	=	particle size multiplier, dimensionless	

The particle size multiplier "*k*" has been added to the basic AP-42 equation to calculate emissions for PM_{10} and $PM_{2.5}$. AP-42 Section 13.4 presents data that suggests the PM_{10} fraction is 1% of the total PM emission

rate. AP-42 has no information on $PM_{2.5}$ emissions. For this analysis, the value of the particle size multiplier is based on the measured distribution of water droplet size in the cooling tower drift loss. The diameter of the airborne particle that would be produced by the evaporation of the liquid water from a drift droplet is given by the following equation from the report *Calculating Realistic PM_{10} Emissions from Cooling Towers*, Abstract No. 216 Session No. AM-1b, Joel Reisman and Gordon Frisbie, Greystone Environmental Consultants, Inc. This analysis is based on actual test data conducted by Environmental Systems Corporation (ESC) at the Electric Power Research Institute (EPRI) test facility in Houston, Texas in 1988 for a large cooling tower. This is the same method described in the New Mexico Environment Department, Air Quality Bureau's technical memorandum dated September 9, 2013 from Daren Zigich entitled, *Calculating TSP, PM-10 and PM-2.5 from Cooling Towers*.

$$d_{droplet} = d_{particle}\left[\frac{10^6 \rho_{salt}}{\rho_{water} C_{TDS}}\right]^{1/3}$$

Where,
- $d_{droplet}$ = Maximum diameter of the drift droplet that would produce a dry particle size of $d_{particle}$ or smaller, microns (µm)
- $d_{particle}$ = Dry particle (particulate matter) particle size, microns
- ρ_{salt} = Density of particle = 2.5 g/cm^3
- ρ_{water} = Density of water = 1.0 g/cm^3
- C_{TDS} = Circulating water total dissolved solids (TDS), parts per million, ppm

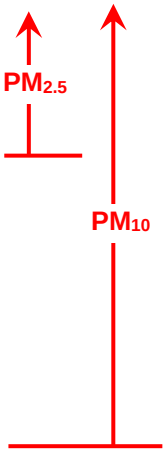
Table 4-7 is the drift loss droplet size distribution as measured for a large cooling tower from the above referenced EPRI test data. For a circulating water TDS of 2,000 ppm, the drift loss droplet size would need to be smaller than 108 µm to form PM_{10} emissions, and less than 27 µm to form $PM_{2.5}$. From Table 4-7, 70.5% of the drift loss would result in PM_{10} emissions, and 0.23% of the drift loss would result in $PM_{2.5}$ emissions. Table 4-6 summarizes the maximum PM, PM_{10}, and $PM_{2.5}$ emissions for the cooling tower based on particle size multiplier "*k*" values of 1.0, 0.705, and 0.00226, respectively. These are the same fractions calculated in the New Mexico Environment Department, Air Quality Bureau's technical memorandum.

TABLE 4-6. Total potential emissions for each mechanical draft cooling tower.

POLLUTANT		*Q* Flowrate gal/min	C_{TDS} TDS Conc. ppm	%DL Drift Loss %	*k* Particle Size Multiplier	Potential Emissions	
						lb/hr	ton/yr
Particulate Matter	PM	2,500	2,450	0.005%	1.00	0.153	0.67
Particulate Matter	PM_{10}	2,500	2,450	0.005%	0.705	0.108	0.47
Particulate Matter	$PM_{2.5}$	2,500	2,450	0.005%	0.0023	0.00035	0.0015

TABLE 4-7. Size distribution of water droplets for cooling towers and the resulting particle size multiplier, k, for particulate matter (PM) emissions.

EPRI Droplet Diameter, µm	Solid Particle Diameter, µm	Particle Size Multiplier, *k* (EPRI % Mass Smaller)
10	0.90	0.00
20	**1.80**	**0.20**
30	2.70	0.23
40	3.60	0.51
50	**4.50**	**1.82**
60	5.40	5.70
70	6.30	21.35
90	8.1	49.81
110	9.9	70.51
130	11.7	82.02
150	13.5	88.01
180	16.2	91.03
210	18.9	92.47
240	21.6	94.09
270	24.3	94.69
300	27.0	96.29
350	31.5	97.01
400	36.0	98.34
450	40.5	99.07
500	45.0	99.07
600	54.0	100.00



Data is from the report Calculating Realistic PM_{10} Emissions from Cooling Towers, Abstract No. 216 Session No. AM-1b, Joel Reisman and Gordon Frisbie, Greystone Environmental Consultants, Inc.

4.4 Diesel Engine Emergency Fire Pump.

The Project will have one new 510 horsepower diesel engine driven fire pump. The specifications for this fire pump are summarized in Table 4-8.

TABLE 4-8. General specifications for the new emergency diesel fire pump.

Manufacturer	Clarke (or similar)
Model	JX6H-UFAD60
Fuel	Diesel Fuel Oil
Engine Type	Diesel
Engine Displacement, liters	13.5
Engine Rating, horsepower	510
Maximum Fuel Flow, gal/hour	27.0

4.4.1 Applicable Requirements.

4.4.1.1 40 CFR 60, Subpart IIII.

This engine will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* under 40 CFR 60, Subpart IIII. These emission standards are summarized below.

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines], g/kWh (g/Hp-hr)

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)

Potential air pollutant emissions for this new fire pump are summarized in Table 4-9. Potential emissions are based on 200 hours per year of operation. Potential CO, NO_x, and PM emissions are based on the above standards in Table 4 of Subpart IIII. For NO_x emissions, the standard is for the combined total of NO_x plus non-methane hydrocarbons (NMHC + NO_x). As a worst-case assumption in this analysis, potential NO_x emissions assume 100% of the emissions are NO_x emissions. Potential VOC emissions are based on the NMHC + NO_x and assume one-half of the total NMHC + NO_x emissions are VOC emissions.

TABLE 4-9. Potential emissions for 510 horsepower diesel engine driven fire pump.

POLLUTANT		Fuel Oil Heat Input	Power Output	Emission Factor		Potential to Emit	
		mmBtu/hr	hp	lb/mmBtu	g/hp-hr	lb/hr	ton/year
Carbon Monoxide	CO	4.20	510	0.70	2.6	2.92	0.29
Nitrogen Oxides	NO_x	4.20	510	0.80	3.0	3.37	0.34
Particulate Matter	PM	4.20	510	0.010	0.15	0.17	0.02
Particulate Matter	PM_{10}	4.20	510	0.010	0.15	0.17	0.02
Particulate Matter	$PM_{2.5}$	4.20	510	0.010	0.15	0.17	0.02
Sulfur Dioxide	SO_2	4.20	510	0.0016		0.007	0.0007
Vol. Org. Cmpds	VOC	4.20	510	0.40	1.5	1.69	0.17
Sulfuric Acid Mist	H_2SO_4	4.20	510	0.00040		0.002	0.0002
Fluorides	F	4.20	510	0.0373		0.157	0.0157
Lead	Pb	4.20	510	0.000009		0.00004	0.000004
Carbon Dioxide	CO_2	4.20	510	163.1		684.8	68.5
Greenhouse Gases	CO_2e	4.20	510	163.8		687.9	68.8

Footnotes

1. Potential emissions are based on 200 hours per year of operation at the full output of 510 hp and a diesel oil fuel oil flow of 30 gal/hr, equal to 4.2 mmBtu/hr.

2. The NOx and PM emission factors in g/hp-hr are the emission standards for stationary fire pump engines with ratings of 30 < HP < 600 in 40 CFR 60, Subpart IIII, Table 4. The CO emission rate is the emission standard for similar model year 2008 and earlier engines.

3. All PM emissions are also assumed to be PM_{10} and $PM_{2.5}$ emissions.

4. The SO_2 emission factor of 0.0016 lb/mmBtu is based on combustion of ultra-low sulfur fuel oil with a sulfur content of less than 15 parts per million (ppm).

5. The VOC emission factor in g/hp-hr is equal to one-half of the emission standard for NOx plus total non-methane hydrocarbons for fire pump engines with ratings of 30 < HP < 600 in 40 CFR 60, Subpart IIII, Table 4.

6. Sulfuric acid mist emissions are based on 25% conversion of SO_2 to sulfuric acid mist in the flue gas.

7. The lead (Pb) and fluorides emission factors are based on combustion of fuel oil from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42,* 5th Edition, Table 1.3-10 and 1.3-11.

8. The emission factors for the greenhouse gases from fuel oil combustion, 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.

Pollutant		Emission Factor	Total GHG Emission Factor	
		lb/mmBtu	CO_2e Factor[4]	lb/mmBtu
Carbon Dioxide	CO_2	163.05	1	163.052
Methane	CH_4	0.0132	25	0.331
Nitrous Oxide	N_2O	0.00132	298	0.394
TOTAL GHG EMISSIONS, AS CO_2e				**163.8**

4.5 Total Expansion Project Potential to Emit.

Table 4-10 is a summary of the total unrestricted emissions for the proposed new Simple Cycle CT Expansion Project. Table 4-11 is a summary of the potential emissions for this Project based on the proposed synthetic minor emission limits detailed in Chapter 7 of this application.

TABLE 4-10. Total unrestricted emissions for the Expansion Project, tons per year.

Pollutant		Combustion Turbines		Nat. Gas Heater	Mechanical Draft Cooling Towers		Fire Pump	Total Project
		CT4	CT5	H1	MDCT1	MDCT2	FP1	
Carbon Monoxide	CO	174.9	174.9	6.1			0.3	356.3
Nitrogen Oxides	NO_x	219.2	219.2	5.7			0.3	444.4
Particulate Matter	PM	49.3	49.3	0.77	0.67	0.67	0.02	100.7
Particulate Matter	PM_{10}	49.3	49.3	0.77	0.47	0.47	0.02	100.3
Particulate Matter	$PM_{2.5}$	49.3	49.3	0.77	0.002	0.002	0.02	99.3
Sulfur Dioxide	SO_2	3.9	3.9	0.09			0.00	7.8
Vol. Org. Cmpds	VOC	30.0	30.0	0.84			0.17	61.0
Sulfuric Acid Mis	H_2SO_4	1.0	1.0	0.009			0.000	1.9
Fluorides (F)	F	0.000	0.000	0.0000			0.0157	0.0157
Lead	Pb	0.003	0.003	0.0001			0.000004	0.0065
Carbon Dioxide	CO_2	755,940	755,940	17,932			68.5	1,529,882
Greenhouse Gases	CO_2e	756,717	756,717	17,951			68.8	1,531,453

TABLE 4-11. Potential emissions for the Expansion Project based on the synthetic minor limits in this application. All emissions are tons per year.

Pollutant		Combustion Turbines		Nat. Gas Heater	Mechanical Draft Cooling Towers		Fire Pump	Total Project
		CT4	CT5	H1	MDCT1	MDCT2	FP1	
Carbon Monoxide	CO	240.0		6.1			0.3	246.4
Nitrogen Oxides	NO_x	240.0		5.7			0.3	246.0
Particulate Matter	PM	49.3	49.3	0.77	0.67	0.67	0.02	100.7
Particulate Matter	PM_{10}	49.3	49.3	0.77	0.47	0.47	0.02	100.3
Particulate Matter	$PM_{2.5}$	49.3	49.3	0.77	0.002	0.002	0.02	99.3
Sulfur Dioxide	SO_2	3.9	3.9	0.09			0.00	7.8
Vol. Org. Cmpds	VOC	30.0	30.0	0.84			0.17	61.0
Sulfuric Acid Mis	H_2SO_4	1.0	1.0	0.009			0.000	1.9
Fluorides (F)	F	0.000	0.000	0.0000			0.0157	0.0157
Lead	Pb	0.003	0.003	0.0001			0.000004	0.0065
Carbon Dioxide	CO_2	755,940	755,940	17,932			68.5	1,529,882
Greenhouse Gases	CO_2e	756,717	756,717	17,951			68.8	1,531,453

Chapter 5. Hazardous Air Pollutant Emissions Analysis.

5.1 Simple Cycle CT Units CT4 and CT5.

For each CT and for all periods of operation, including both normal operation and periods of startup and shutdown, the emission factors for all HAP emissions ***except formaldehyde*** are *uncontrolled* emission factors from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, Volume 1: Stationary Point and Area Sources, Section 3.1, Stationary Gas Turbines for Electricity Generation, Table 3.1-3.

5.1.1 Formaldehyde Emissions.

During normal operation, potential formaldehyde emissions are based on the emission standard in the *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 CFR 63 Subpart YYYY. In the preamble to the proposed rules for Subpart YYYY, the U.S. EPA stated[1]:

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

APS is proposing to install and operate oxidation catalyst systems on the proposed units CT4 and CT5. The U.S. EPA's Information Collection Request (ICR), which was conducted recently in a reconsideration rulemaking for Subpart YYYY, has several test reports for General Electric LM6000PC units at the Middletown Power LLC Generating Plant in Middletown, Connecticut[2]. These tests were conducted in September 2022 on natural gas-fired CTs also equipped with oxidation catalyst systems. The test results indicate average formaldehyde emission rates of 35.55 ppbdv at 15% O_2 on Unit 13, and 28.38 ppbdv at 15% O_2 on Unit 15. These emission rates are approximately one-third of the Subpart YYYY emission limit. Based on the U.S. EPA's evaluation of formaldehyde from similar CTs under Subpart YYYY, APS has concluded that the normal operation formaldehyde emission rate of 91 ppbdv at 15% O_2, except during turbine startup, equal to an emission rate of 0.000235 lb/mmBtu, is a conservative estimate of the maximum normal operation formaldehyde emissions from the proposed CTs in this application.

During periods of startup and shutdown, formaldehyde emissions may be elevated because the CTs are not operating in their full lean premix firing mode and the oxidation catalysts may not be fully operational. As a conservative estimate of formaldehyde emissions during startup and shutdown, the all loads, uncontrolled emission factor for natural gas-fired CTs of 0.00312 lb/mmBtu was used from the U.S. EPA's *EMISSION FACTOR DOCUMENTATION FOR AP-42 SECTION 3.1 STATIONARY GAS TURBINES,* April 2000, Table 3.4-1. Note that this factor is more than 13 times higher than the normal operation emission rate.

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

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

In accordance with Table 1 of Subpart YYYY, new lean premix gas-fired CTs must limit formaldehyde (CH_2O) to 91 parts per billion on a dry, volume basis (ppbdv) or less at 15% O_2, except during startup. This concentration may be converted to lb/mmBtu based on the following equation:

$$E = \frac{20.9KC_hF}{20.9 - \%O_2}$$

Where, E = Pollutant emission rate, lb/mmBtu C_h = Pollutant concentration, ppmdv
K_{CH2O} = 8.36 x 10^{-8} lb CH_2O/scf-ppm CH_2O F = Fuel-based Factor = 8,710 dscf/mmBtu

Substituting these values into the above equation, formaldehyde emissions of 91 ppbdv (0.091 ppmdv) at 15% O_2 is equal to an emission rate of 0.000235 lb/mmBtu:

$$E = \frac{20.9KC_hF}{20.9 - \%O_2} = \frac{20.9\left(8.36 \times 10^{-8}\ \frac{\text{lb } CH_2O}{\text{scf} \cdot \text{ ppm } CH_2O}\right)(0.091\text{ ppm})\left(8{,}710\ \frac{\text{dscf}}{\text{mmBtu}}\right)}{20.9 - 15}$$

$$E = 0.000235\ \frac{\text{lb}}{\text{mmBtu}}$$

The value of K_{CH2O}, in units of lb CH_2O/scf-ppm CH_2O, may be derived from the Ideal Gas Law at standard conditions (1.0 atmosphere and 32 °F) as follows:

PV = nRT (Ideal Gas Law)

Where, P = Absolute Pressure, atmospheres R = Ideal Gas Law Constant, 0.73024 atm-ft^3/lb-mole-˚R
V = Volume, cubic feet (ft^3) T = Absolute Temperature, ˚R
n = Moles of Gas, lb-moles

The value of K may be calculated for formaldehyde, molecular weight 30.026 lb/lb-mole, by rearranging the Ideal Gas Law and using the molecular weight (MW) of formaldehyde:

$$\frac{(n)(MW)}{V} = \frac{(P)(MW)}{RT} = \frac{(1.0\text{ atm})\left(30.026\ \frac{\text{lb } CH_2O}{\text{lbmole } CH_2O}\right)}{\left(0.73024\ \frac{\text{atm} \cdot \text{ft}^3}{\text{lbmole} \cdot {}^\circ\text{R}}\right)(459.67 + 32\ {}^\circ\text{R})} = 0.0836\ \frac{\text{lb } CH_2O}{\text{ft}^3\ CH_2O}$$

The value of K is expressed in pounds of CH_2O per standard cubic foot ***per ppm of CH_2O***. Therefore, the value of K, expressed per ppm, is:

$$K_{CH2O} = 0.0836\ \frac{\text{lb } CH_2O}{\text{ft}^3\ CH_2O} \times \frac{1.0\text{ ft}^3\ CH_2O}{1{,}000{,}000\text{ ppm } CH_2O} = 8.36 \times 10^{-8}\ \frac{\text{lb } CH_2O}{\text{scf} \cdot \text{ ppm } CH_2O}$$

This limit does not apply during periods of startup. Under 40 CFR § 63.6175, *Startup* begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 1 hour, whichever is less. Table 5-1 is a summary of the potential HAP emissions for each new simple cycle CT.

TABLE 5-1. Potential hazardous air pollutant (HAP) emissions for each new simple cycle CT.

POLLUTANT	CAS No.	Normal Operation					Startup and Shutdown Operation					Total Potential to Emit
		Emission Factor	Heat Input		Potential Emissions		Emission Factor	Operating Rates		Potential Emissions		
		lb/mmBtu	mmBtu /hr	mmBtu/yr	lb/hr	ton/yr	lb/mmBtu	mmBtu /event	SUSD /year	lb / SUSD	ton/yr	ton/yr
Acetaldehyde	75-07-0	0.000040	3,279	12,924,700	0.131	0.26	0.000040	1,007	365	0.0403	0.007	0.27
Acrolein	107-02-8	0.000006	3,279	12,924,700	0.021	0.04	0.000006	1,007	365	0.0064	0.001	0.04
Benzene	71-43-2	0.000012	3,279	12,924,700	0.039	0.08	0.000012	1,007	365	0.0121	0.002	0.08
1,3-Butadiene	106-99-0	0.000000	3,279	12,924,700	0.001	0.00	0.000000	1,007	365	0.0004	0.000	0.00
Ethylbenzene	100-41-4	0.000032	3,279	12,924,700	0.105	0.21	0.000032	1,007	365	0.0322	0.006	0.21
Formaldehyde	50-00-0	0.000235	3,279	12,924,700	0.770	1.52	0.003120	1,007	365	3.1418	0.573	2.09
Hexane	110-54-3	0.000259	3,279	12,924,700	0.850	1.67	0.000259	1,007	365	0.2610	0.048	1.72
Xylene	1330-20-7	0.000064	3,279	12,924,700	0.210	0.41	0.000064	1,007	365	0.0644	0.012	0.43
Naphthalene	91-20-3	0.000001	3,279	12,924,700	0.004	0.01	0.000001	1,007	365	0.0013	0.000	0.01
PAH		0.000002	3,279	12,924,700	0.007	0.01	0.000002	1,007	365	0.0022	0.000	0.01
Propylene oxide	75-56-9	0.000029	3,279	12,924,700	0.095	0.19	0.000029	1,007	365	0.0292	0.005	0.19
Toluene	108-88-3	0.000130	3,279	12,924,700	0.426	0.84	0.000130	1,007	365	0.1309	0.024	0.86
TOTAL		**0.000812**	**3,279**	12,924,700	2.66	5.24	0.00370	1,007	365	3.72	0.679	5.92

Footnotes

1. Potential emissions during normal operation are based on a maximum allowable heat input to each CT of 12,924,700 mmBtu per year.
2. The emission factors for all HAPs and all periods of operation ***except formaldehyde emissions*** are *uncontrolled* emission factors from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, Volume 1: Stationary Point and Area Sources, Section 3.1, Stationary Gas Turbines for Electricity Generation.
3. Formaldehyde (CH_2O) emissions during normal operation are based on the emission limit of 91 parts per billion (ppbdv) or less at 15% O_2 for lean premix and diffusion-flame natural gas and oil-fired CTs located at major sources of HAPs in accordance with the *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 CFR 63, Subpart YYYY.
4. During periods of startup and shutdown, formaldehyde emissions are based on the all loads, uncontrolled emission factor for natural gas-fired CTs of 0.000312 lb/mmBtu from the U.S. EPA's *EMISSION FACTOR DOCUMENTATION FOR AP-42 SECTION 3.1 STATIONARY GAS TURBINES*, April 2000, Table 3.4-1.

5.2 Natural Gas-Fired Natural Gas Heater.

Potential HAP emissions for the natural gas-fired natural gas heater based on 8,760 hours per year of continuous operation for are included in Table 5-2. The emission factors are for natural gas-fired boilers from the U.S. EPA's AP-42, *Compilation of Air Pollutant Emission Factors*, 5th Edition, Natural Gas Combustion, Tables 1.4-3 and 1.4-4. Emission factors were converted from lb per million cubic feet of natural gas to pounds per million Btu based on a natural gas heat content of 1,000 Btu Aper cubic foot of gas.

TABLE 5-2. Potential HAP emissions for the natural gas-fired natural gas heater.

Pollutant	CAS No.	Emission Factor		Heat Input Rate	Potential to Emit	
		lb/10^6 scf	lb/mmBtu	mmBtu/hr	lb/hr	ton/yr
Arsenic	7440-38-2	2.0E-04	2.0E-07	35	0.0000	0.0000
Barium	7440-39-3	4.4E-03	4.4E-06	35	0.0002	0.0007
Benzene	71-43-2	2.1E-03	2.1E-06	35	0.0001	0.0003
Cadmium	7440-43-9	1.1E-03	1.1E-06	35	0.0000	0.0002
Chromium	7440-47-3	1.4E-03	1.4E-06	35	0.0000	0.0002
Cobalt	7440-48-4	8.4E-05	8.4E-08	35	0.0000	0.0000
Copper	7440-50-8	8.5E-04	8.5E-07	35	0.0000	0.0001
Dichlorobenzene	25321-22-6	1.2E-03	1.2E-06	35	0.0000	0.0002
Formaldehyde	50-00-0	7.5E-02	7.5E-05	35	0.0026	0.0115
Hexane	110-54-3	1.8E+00	1.8E-03	35	0.0630	0.2759
Hydrogen Chloride	7647-01-0		1.2E-05	35	0.0004	0.0019
Manganese	7439-96-5	3.8E-04	3.8E-07	35	0.0000	0.0001
Mercury	7439-97-6	2.6E-04	2.6E-07	35	0.0000	0.0000
Molybdenum	7439-98-7	1.1E-03	1.1E-06	35	0.0000	0.0002
Naphthalene	91-20-3	6.1E-04	6.1E-07	35	0.0000	0.0001
Nickel	7440-02-0	2.1E-03	2.1E-06	35	0.0001	0.0003
Toluene	108-88-3	3.4E-03	3.4E-06	35	0.0001	0.0005
Vanadium	7440-62-2	2.3E-03	2.3E-06	35	0.0001	0.0004
TOTAL, ALL HAPs COMBINED			**1.9E-03**	**35**	**0.07**	**0.29**

5.3 Diesel Engine Emergency Fire Pump.

Potential HAP emissions for the diesel engine-driven fire pump based on an operating limit of 200 hours per year are included in Table 5-3. Hazardous air pollutant 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.

TABLE 5-3. Potential HAP emissions for the diesel engine-driven fire pump based on an operating limit of 200 hours per year.

AIR POLLUTANT	CAS #	Emission Factor[1]	Heat Input	Potential to Emit	
		lb/mmBtu	mmBtu/hr	lb/hr	ton/yr
Benzene	71-43-2	7.76E-04	4.20	0.00326	0.00033
Toluene	108-88-3	2.81E-04	4.20	0.00118	0.00012
Xylene	1330-20-7	1.93E-04	4.20	0.00081	0.00008
Formaldehyde	50-00-0	7.89E-05	4.20	0.00033	0.00003
Acetaldehyde	75-07-0	2.52E-05	4.20	0.00011	0.00001
Acrolein	107-02-8	7.88E-06	4.20	0.00003	0.00000
Naphthalene	91-20-3	1.30E-04	4.20	0.00055	0.00005
Total PAH		2.12E-04	4.20	0.00089	0.00009
TOTAL					**0.0007**

Footnotes

1. Hazardous air pollutant 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 to less than 200 hours per year.

3. The maximum heat input rate is based on 30 gallons of fuel oil per hour, and a fuel oil heat value of 140,000 Btu per gallon.

5.4 Total Potential Facility-wide HAP Emissions.

The total potential facility-wide HAP emissions, including the Expansion Project emissions units, are summarized in Table 5-4. Please note that the cooling towers are not a significant source of HAP emissions. From Table 5-4, the facility will be a minor or area source of HAP emissions.

TABLE 5-4. Total potential HAP emissions for the Saguaro Power Plant including the new Project, tons per year.

Hazardous Air Pollutant	CAS Number	EXISTING FACILITY				EXPANSION PROJECT				TOTAL FACILITY
		Simple Cycle CTs			BESS Generator	Simple Cycle CTs		Heater	Fire Pump	
		CT1	CT2	CT3		CT4	CT5	H1	FP1	
1,3-Butadiene	106-99-0	0.00	0.00	0.0017		0.00	0.00			0.01
Acetaldehyde	75-07-0	0.16	0.16	0.1600	0.0001	0.27	0.27			1.02
Acrolein	107-02-8	0.03	0.03	0.0256	0.0000	0.04	0.04			0.16
Benzene	71-43-2	0.05	0.05	0.0480	0.0016	0.08	0.08	0.00032		0.31
Dichlorobenzene	25321-22-6		0.00					0.00018		0.00
Ethylbenzene	100-41-4	0.13	0.13	0.1280		0.21	0.21			0.82
Formaldehyde	50-00-0	0.97	0.97	0.9398	0.0002	2.09	2.09	0.011	0.00003	7.07
n-Hexane	110-54-3	1.07	1.07	1.0365		1.72	1.72	0.28		6.89
Naphthalene	91-20-3	0.01	0.01	0.0052		0.01	0.01	0.00009	0.00005	0.03
PAH		0.01	0.01	0.0088	0.0004	0.01	0.01		0.00009	0.06
Propylene oxide	75-56-9	0.12	0.12	0.1160		0.19	0.19			0.74
Toluene	108-88-3	0.53	0.53	0.5199	0.0006	0.86	0.86	0.00052	0.00012	3.32
Xylene	1330-20-7	0.26	0.26	0.2559	0.0004	0.43	0.43		0.00008	1.63
Arsenic	7440-38-2							0.00003		0.00
Barium	7440-39-3							0.00067	0.00001	0.00
Cadmium	7440-43-9							0.00017	0.00000	0.00
Hydrogen Chloride	7647-01-0							0.00190	0.00033	0.00
Chromium	7440-47-3							0.00021		0.00
Cobalt	7440-48-4							0.00001		0.00
Copper	7440-50-8							0.00013		0.00
Manganese	7439-96-5							0.00006		0.00
Mercury	7439-97-6							0.00004		0.00
Molybdenum	7439-98-7							0.00017		0.00
Nickel	7440-02-0							0.00032		0.00
Vanadium	7440-62-2							0.00035		0.00
TOTAL		**3.34**	**3.34**	**3.25**	**0.00**	**5.92**	**5.92**	**0.29**	**0.00**	**22.06**

Chapter 6. Applicable Requirements.

6.1 R18-2 Article 4. Permit requirements for new major sources and major modifications to existing major sources.

6.1.1 PSD Applicability.

The Saguaro Power Plant is located in Section 15, Township 10S, Range 10E, Red Rock, Arizona. This location is designated as attainment or unclassifiable for all pollutants. Therefore, the facility is subject to the Prevention of Significant Deterioration (PSD) program for all regulated pollutants. Arizona Administrative Code, A.A.C. R18-2-401.13. and Pinal County Air Quality Control District (PCAQCD) Code of Regulations, Article 3. *Permit Requirements for New Major Sources and Major Modifications to Existing Major Sources*, Pinal County Code § 3-3-203.2.b. defines "Major source" as any stationary source located in an attainment or unclassifiable area which emits, or has the potential to emit, 100 tons per year or more of any PSD regulated pollutant if the source is classified as a categorical source, or 250 tons per year or more of any such pollutant if the source is not classified as a categorical source. With the removal of the fossil fuel-fired steam electric units (Steam Unit 1 and 2), the Saguaro Power Plant is not a categorical source as defined in A.A.C. R18-2-101.23 and Code § 1-3-140.25. Therefore, the major source threshold for the Saguaro Power Plant is 250 tons per year of any PSD regulated pollutant.

Table 6-1 summarizes the unrestricted potential emissions for the Saguaro Power Plant after the Expansion Project, based on 8,760 hours per year of continuous operation at the maximum rated output for each of the existing CTs and a 45% capacity factor for the two proposed CTs. Unrestricted potential emissions for the existing CTs and for all pollutants ***except CO and NO_x emissions for CT3*** are based on emission factors for uncontrolled, natural gas-fired combustion turbines from the U.S. EPA's *AP-42, Compilation of Air Pollutant Emission Factors, 5th Edition*, section 3.1, Tables 3.1-1 and 3.1-2a. NO_x emissions for CT3 are based on the applicable emission standard in 40 CFR 60 Subpart GG of 75 ppmdv at 15% O_2. The CO emission rate for CT3 is the vendor stated emission rate of 25 ppmdv at 15% O_2. For the new CTs, potential emissions in Table 6-1 are based on the operational restriction of 45% capacity factor for each CT, and a proposed PM, PM_{10}, and $PM_{2.5}$ emission limit of 25 pounds per hour.

From Table 6-1, the unrestricted potential emissions for all PSD regulated pollutants ***except*** CO and NO_x emissions are less than the major source threshold for the Saguaro Power Plant of 250 tons per year. Therefore, to limit all PSD regulated pollutants for the entire facility, including the new emissions units, below the major source threshold, synthetic minor emission limits are only required for CO and NO_x emissions. Furthermore, because the combined unrestricted potential CO and NO_x emissions for all of the other emissions units except the CTs is less than 8 tons per year for each pollutant, restricting the potential emissions for the combustion turbine units CT1, CT2, CT3, CT4, and CT5 ***combined*** to less than 240 tons per year will ensure that the total potential emissions for the entire facility are limited to less than 250 tons per year. In accordance with 40 CFR §52.21(b)(49)(iv), the pollutant GHGs is subject to regulation if the

stationary source is an existing major stationary source for a regulated NSR pollutant that is not GHGs, and also will have an emissions increase of a regulated NSR pollutant, and an emissions increase of 75,000 tpy CO_2e or more. By restricting all PSD regulated pollutants except GHG emissions below the major source threshold levels, GHG emissions are also not subject to regulation under the PSD program.

With this application and as shown in Table 6-2, APS is proposing to limit the potential to emit for CO and NOx emissions for the Saguaro Power Plant combustion turbine units CT1, CT2, CT3, CT4, and CT5 combined to less than 240 tons per year. This will limit all PSD regulated pollutants below the major source threshold of 250 tons per year. Therefore, with this application, the Saguaro Power Plant will be classified as a synthetic minor source under the PSD program.

6.2 Pinal County Code § 3-1-040. Applicability and classes of permits.

In accordance with Pinal County Code, Chapter 3. Permits and Permit Revisions and § 3-1-040.A, a permit or permit revision is required for undertaking a modification of a source subject to regulation under this chapter. The term 'modification' is defined at Code § 1-3-140.85 as "[a] physical change in or change in the method of operation of a source which increases the actual emissions … by more than an amount numerically equal to a corresponding de minimis amount. Under Code § 1-3-140.37, the term 'de minimis' is the lesser of the potential of the source to emit one ton per year or 5.5 pounds per day. From Chapter 4, the Simple Cycle CT Expansion Project results in emissions increases greater than the de minimis levels. Therefore, a permit revision under Code § 3-1-040 is required for the proposed Project. This application for a permit revision constitutes an application for approval under this provision.

6.3 Pinal County Code § 3-2-195. Significant permit revisions.

In accordance with Pinal County Code § 3-2-190 and A.A.C. R18-2-319.A.4, any changes that require establishment of a permit term or condition to avoid an applicable requirement are not considered a minor permit revision and are subject to significant permit revision requirements under Code § 3-2-195 and A.A.C. R18-2-320.A. Because APS is requesting federally enforceable emission and operating limits for the existing emissions units and also for the proposed new emissions units to keep the Expansion Project potential to emit below the major source threshold levels for the Pinal County, State of Arizona a significant permit revision to the Saguaro Class I Permit is required for the proposed Project. This document is an application for a significant permit revision under Code § 3-2-195 and A.A.C. R18-2-320.

TABLE 6-1. Total unrestricted potential emissions for the Saguaro Power Plant including the new Expansion Project. All emissions are tons per year.

Pollutant		Simple Cycle CTs					Mechanical Cooling Towers					BESS Emer. Generator	Nat. Gas Heater H1	Fire Pump FP1	TOTAL FACILITY	Major Source Threshold	OVER?
		CT1	CT2	CT3	CT4	CT5	MCT1	MCT2	MCT3	MCT4	MCT5						
Carbon Monoxide	CO	337.3	337.3	228.8	174.9	174.9						1.1	6.1	0.3	1,260.7	250	**YES**
Nitrogen Oxides	NO_x	1,316.1	1,316.1	1,129.1	219.2	219.2						2.0	5.7	0.3	4,207.7	250	**YES**
Particulate Matter	PM	27.1	27.1	27.0	49.3	49.3	0.1	0.1	0.8	0.67	0.67	0.1	0.77	0.02	183.1	250	**NO**
Particulate Matter	PM_{10}	27.1	27.1	27.0	49.3	49.3	0.09	0.09	0.59	0.47	0.47	0.1	0.77	0.02	182.4	250	**NO**
Particulate Matter	$PM_{2.5}$	27.1	27.1	27.0	49.3	49.3	0.0003	0.0003	0.0019	0.0015	0.0015	0.1	0.77	0.02	180.7	250	**NO**
Sulfur Dioxide	SO_2	2.5	2.5	2.5	3.9	3.9						0.0	0.09	0.00	15.2	250	**NO**
Vol. Org. Cmpds	VOC	8.6	8.6	8.6	30.0	30.0						2.0	0.84	0.17	88.9	250	**NO**
Sulfuric Acid Mist	H_2SO_4	0.6	0.6	0.6	1.0	1.0						0.00	0.009	0.000	3.8	250	**NO**
Fluorides (F)	F	0.0	0	0	0.000	0.000						0.0746	0.0000	0.0157	0.1	250	**NO**
Lead	Pb	0.002	0.002	0.002	0.003	0.003						0.0000	0.00008	0.000004	0.0	5.0	**NO**
Carbon Dioxide	CO_2	481,102	481,102	478,027	755,940	755,940						326.1	17,932.4	68.5	2,970,438	n/a	**n/a**
Greenhouse Gases	CO_2e	481,596	481,596	478,518	756,717	756,717						327.2	17,950.9	68.8	2,973,490	75,000	**YES**

TABLE 6-2. Total potential emissions for the Saguaro Power Plant including the new Expansion Project based on the proposed PSD synthetic minor limits. All emissions are tons per year.

Pollutant		Simple Cycle CTs					Mechanical Cooling Towers					BESS Emer. Generator	Nat. Gas Heater H1	Fire Pump FP1	TOTAL FACILITY	Major Source Threshold	OVER?
		CT1	CT2	CT3	CT4	CT5	MCT1	MCT2	MCT3	MCT4	MCT5						
Carbon Monoxide	CO	240.0										1.1	6.1	0.3	247.5	250	**NO**
Nitrogen Oxides	NO_x	240.0										2.0	5.7	0.3	248.0	250	**NO**
Particulate Matter	PM	27.1	27.1	27.0	49.3	49.3	0.1	0.1	0.8	0.7	0.7	0.1	0.77	0.02	183.1	250	**NO**
Particulate Matter	PM_{10}	27.1	27.1	27.0	49.3	49.3	0.09	0.09	0.59	0.47	0.47	0.1	0.77	0.02	182.4	250	**NO**
Particulate Matter	$PM_{2.5}$	27.1	27.1	27.0	49.3	49.3	0.0003	0.0003	0.0019	0.0015	0.0015	0.1	0.77	0.02	180.7	250	**NO**
Sulfur Dioxide	SO_2	2.5	2.5	2.5	3.9	3.9						0.0	0.09	0.00	15.2	250	**NO**
Vol. Org. Cmpds	VOC	8.6	8.6	8.6	30.0	30.0						2.0	0.84	0.17	88.9	250	**NO**
Sulfuric Acid Mist	H_2SO_4	0.6	0.6	0.6	1.0	1.0						0.00	0.009	0.000	3.8	250	**NO**
Fluorides (F)	F	0.0	0	0	0.000	0.000						0.0746	0.0000	0.0157	0.1	250	**NO**
Lead	Pb	0.002	0.002	0.002	0.003	0.003						0.0000	0.00008	0.000004	0.0	5.0	**NO**
Carbon Dioxide	CO_2	481,102	481,102	478,027	755,940	755,940						326.1	17,932.4	68.5	2,970,438	n/a	**n/a**
Greenhouse Gases	CO_2e	481,596	481,596	478,518	756,717	756,717						327.2	17,950.9	68.8	2,973,490	n/a	**n/a**

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

AAC R18-2-334. Minor New Source Review, applies to any minor NSR modification to a Class I or Class II source. "Minor NSR Modification" means "Any physical change in or change in the method of operation of an emission unit or a stationary source that … increases the potential to emit of a regulated minor NSR pollutant by an amount greater than or equal to the permitting exemption thresholds in AAC R18-2-101.102. Table 6-3 is a summary of the proposed new emissions units compared to the permitting exemption thresholds. From Table 6-3, the Project will exceed the minor NSR threshold for CO, NO_x, PM_{10}, $PM_{2.5}$, and VOC emissions.

TABLE 6-3. Potential emission increases for the Saguaro Expansion Project compared to the "Significant" levels in AAC R18-2-101(131), tons per year.

Pollutant		Total Project Potential to Emit	Minor NSR Threshold	OVER?
Carbon Monoxide	CO	246.4	50	**YES**
Nitrogen Oxides	NO_x	246.0	20	**YES**
Particulate Matter	PM_{10}	100.3	7.5	**YES**
Particulate Matter	$PM_{2.5}$	99.3	5	**YES**
Sulfur Dioxide	SO_2	7.8	20	**NO**
Vol. Org. Compounds	VOC	61.0	20	**YES**

The requirements of the minor NSR program include the requirement to apply reasonably available control technology (RACT) to the emissions units **OR** conduct an ambient air quality assessment. The requirements from R18-2-334 state:

> C. The Director shall not issue a proposed final Class I permit or permit revision or a Class II permit or permit revision subject to this Section to a person proposing to construct a new source or make a minor NSR modification unless the source or modification meets **one of the following conditions** for each regulated minor NSR pollutant subject to this Section (**emphasis added**):
>
> 1. The owner or operator elects to implement RACT.
>
> b. In the case of a minor NSR modification, the owner or operator shall implement RACT for each emissions unit that will experience an increase in the potential to emit a regulated minor NSR pollutant equal to or greater than 20% of the permitting exemption threshold.
>
> 2. An ambient air quality assessment demonstrates that emissions from the source or minor NSR modification will not interfere with attainment or maintenance of a national ambient air quality standard in any area.

b. The requirements of this subsection shall be satisfied, if the results of the screening or more refined model conducted pursuant to subsection (B)(2)(a) demonstrate either of the following:

   i. Ambient concentrations resulting from emissions from the source or modification combined with existing concentrations of regulated minor NSR pollutants will not interfere with attainment or maintenance of a national ambient air quality standard.

   ii. Emissions from the source or minor modification will have an ambient impact below the significance levels as defined in R18-2-401.

This application includes an ambient air quality assessment that demonstrates that CO, NO_x, $PM_{10,}$ and $PM_{2.5}$ emissions from the minor NSR modification will not interfere with attainment or maintenance of a national ambient air quality standard.

6.5 Pinal County Code § 3-7-590 Class I permit fees.

Per Code § 3-7-590.D.2, an application fee of $1,000 is applicable for an application for a significant permit revision to a Class I permit. A check for the application fee payable to "Pinal County Air Quality Control Department" is attached to this application.

6.6 Pinal County Code § 5-23-1010 Standards of Performance for Stationary Rotating Machinery.

In accordance with Code § 5-23-990, requirements of this standard are applicable to the proposed 'stationary gas turbines' under the CT Project. For equipment with heat input less than 4,200 MMBtu per hour, maximum allowable particulate matter emissions are determined using the following equation:

$$E = 1.02*Q^{0.769}$$

Where, E = the maximum allowable particulate emissions rate in pounds-mass per hour
Q = the total heat input of all operating fuel burning units on a plant or premises in MMBtu per hour

In addition, the proposed CTs are not allowed to emit smoke for any period greater than 10 consecutive seconds which exceeds 40% opacity. Visible emissions when starting cold equipment shall be exempt from this requirement for the first 10 minutes. The proposed CTs will only use natural gas and will meet these emission standards.

6.7 40 CFR 60 Subpart KKKKa.

On January 9, 2026, the U.S. Environmental Protection Agency (U.S. EPA) finalized amendments to the *Standards of Performance for Stationary Combustion Turbines*, 40 CFR 60, Subpart KKKKa. These amendments set standards of performance for emissions of nitrogen oxide (NO_x) and sulfur dioxide (SO_2) from stationary CTs. The applicability requirements in 40 CFR § 60.4305a state:

> **§ 60.4305a Does this subpart apply to my stationary combustion turbine?**
>
> (a) Except as provided for in § 60.4310a, you are subject to this subpart if you own or operate a stationary combustion turbine that commenced construction, modification, or reconstruction after December 13, 2024, and that has a base load rating equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h)). Any additional heat input from duct burners used with heat recovery steam generating (HRSG) units or fuel preheaters is not included in the heat input value used to determine the applicability of this subpart to a given stationary combustion turbine. However, this subpart does apply to emissions from any associated HRSG and duct burner(s) that are associated with a combustion turbine subject to this subpart.
>
> (b) A stationary combustion turbine subject to this subpart is not subject to subpart GG or subpart KKKK of this part.

6.7.1 Nitrogen Oxides (NO_x) Emissions.

Under Subpart KKKKa, the proposed new CTs are large CTs with a base-load rated heat input greater than 850 mmBtu per hour. For these CTs, there are two subcategories of standards depending on whether the utilization is less than or more than 45%. Furthermore, for large CTs with a utilization rate of less than 45%, there are two (2) NO_x emission standards based on the "design efficiency" of the CT. In the preamble to the final rule, EPA stated:

> "Efficiency for purposes of subcategorization in 40 CFR part 60, subpart KKKKa refers to the design efficiency of a specific class or type of stationary combustion turbine according to manufacturer specifications. Turbine manufacturers list this value as a percentage based on the HHV of the individual turbine design."

For the proposed simple cycle CTs, the design efficiency based on the higher heating value (HHV) of the fuel is 37.2% based on the gross electric output of the CT, or 37.1% based on the net electric output. The applicable emission standards for these simple cycle CTs from Subpart KKKKa, Table 1 are shown below. For a *low-utilization source* (a new medium or large CT with a 12-calendar-month capacity factor less than or equal to 45 percent), **the applicable emission standards are highlighted in green.** In addition, **and highlighted in gray**, when demonstrating compliance with the input-based standards, these CTs are also subject to the standard of 96 ppm at 15 percent O_2 when operating at ambient temperatures less than 0°F (-18°C), and/or operating at less than 70 percent of the base load rating. ***Please note that with this application, APS proposes limiting the 12-calendar-month capacity factor of each CT to no more than 45%.***

Excerpts from Table 1 to Subpart KKKKa of Part 60 - Nitrogen Oxide Emission Standards for Stationary Combustion Turbines

Combustion Turbine Type	Combustion Turbine Base Load Rated Heat Input (HHV)	Input-Based NO_x Emission Standard[1]	Optional Output-Based NO_x Standard[2]
New, firing natural gas with utilization rate > 45 percent	> 850 MMBtu/h	5 ppm at 15 percent O_2 or 7.9 ng/J (0.018 lb/MMBtu)	0.054 kg/MWh-gross (0.12 lb/MWh-gross) 0.055 kg/MWh-net (0.12 lb/MWh-net)
New, firing natural gas with utilization rate ≤ 45 percent and with design efficiency ≥ 38 percent	> 850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net)
New, firing natural gas with utilization rate ≤ 45 percent and with design efficiency < 38 percent	**> 850 MMBtu/h**	**9 ppm at 15 percent O_2 or 14 ng/J (0.033 lb/MMBtu)**	**0.17 kg/MWh-gross (0.37 lb/MWh-gross) 0.17 kg/MWh-net (0.38 lb/MWh-net)**
Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0°F (-18°C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating	**> 300 MMBtu/h**	**96 ppm at 15 percent O_2 or 150 ng/J (0.35 lb/MMBtu)**	**N/A**

[1] *Input-based standards are determined on a 4-operating-hour rolling average basis.*
[2] *Output-based standards are determined on a 30-operating-day average basis.*

The applicable standards for the proposed CTs may be summarized as follows:

Low - utilization source with a capacity factor ≤ 45%	1. 9 ppm at 15 percent O_2 (0.033 lb/mmBtu) based on a 4-hour rolling average, ***AND*** 96 ppm at 15 percent O_2 (0.35 lb/mmBtu) when operating at less than 70 percent of base load rating, or when operating at temperatures less than 0 °F. ***OR*** 2. 0.37 lb/MWh based on a 30-operating day rolling average.

EPA set both an input based emission standard which are based on a 4-operating-hour rolling average basis and an optional output based emission standard which is based on a 30-operating-day average basis. In accordance with 40 CFR § 60.4350a(h), "Hours are not subcategorized by load for the purposes of determining the applicable output-based standard. The emissions standard for all hours, regardless of load, is the otherwise applicable full load emissions standard." For these simple cycle CTs, the output based

performance standard is therefore 0.37 lb/MWh-gross for ALL hours of operation.

For compliance with the input based standards, 40 CFR § 60.4350a(g), states:

> (g) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess NOx emissions are determined on a 4-operating-hour averaging period basis using the NOx CEMS data and procedures specified in paragraphs (g)(1) and (2) of this section as applicable to the NOx emissions standard in table 1 to this subpart.
>
> (1) For each 4-operating-hour period, compute the 4-operating-hour rolling average NOx emissions as the heat input weighted average of the hourly average of NOx emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (g)(2) of this section. Calculate a 4-operating-hour rolling average NOx emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (e.g., a valid 4-operating-hour rolling average NOx emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).
>
> **(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average NOx emissions rate and the applicable 4-operating-hour rolling average NOx emissions standard, calculated using hourly values in table 1 to this subpart, using equation 4 to this section.**

Therefore, when demonstrating compliance with the heat input-based standard, you must calculate the heat input weighted actual emission rate AND the heat input weighted emission limit. In other words, both the actual emission rate and the emission limit are calculated for each hour of operation based on whether the CT was operating above or below 70% of the base load rating.

6.7.2 Sulfur Dioxide (SO_2) Emissions.

The applicable new SO_2 emission standards under Subpart KKKKa for the proposed CTs, are the same as the standards under Subpart KKKK:

> **§ 60.4330a What SO_2 emissions standard must I meet?**
>
> **(a**) Except as provided for in paragraphs (b) through (e) of this section, for each new, modified, or reconstructed stationary combustion turbine you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either:
>
> (1) 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output; or
>
> (2) 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

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

6.8 Acid Rain Program.

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

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

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

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

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

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

Based on these requirements, the new CTs will be fossil fuel-fired combustion devices that commenced commercial operation on or after November 15, 1990. These new CTs will also be utility units. Therefore, these new CTs will be affected units under the Acid Rain Program. APS will submit an Acid Rain Permit application to EPA.

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

The *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 CFR Part 63, Subpart YYYY apply to new and existing combustion sources located at a major source of hazardous air pollutants (HAPs). In accordance with 40 CFR § 63.6090(a)(2), a stationary combustion turbine is new if you commenced construction of the stationary combustion turbine after January 14, 2003. However, based on the emissions analysis in Chapter 4, the Saguaro Power Plant will be a minor or area source of HAPs. Therefore, the proposed new CTs are not subject to Subpart YYYY.

6.10 Compliance Assurance Monitoring, 40 CFR Part 64.

The Compliance Assurance Monitoring (CAM) program is codified in 40 CFR Part 64. CAM plan requirements generally apply to any pollutant specific emissions unit:

1. Having pre-control device potential emissions above the major source threshold of 100 tons per year, and
2. Using a control device to achieve compliance with an emission limitation or standard.

Pre-control device NO_x and CO emissions for these new CTs exceed this threshold. Note that PM, PM_{10}, and $PM_{2.5}$ emissions are not subject to CAM requirements because there is no control device used to achieve compliance with the PM emission limit.

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

There are no specific applicable requirements for CO emissions from these CTs under a New Source Performance Standard (NSPS) or under any National Emission Standard for Hazardous Air Pollutants (NESHAP). APS is proposing to use CEMS for monitoring CO and NO_x emissions from the proposed new CTs. Therefore, in accordance with 40 CFR § 64.2(b)(1)(vi), CAM plan requirements do not apply for NO_x and CO emissions from the proposed units.

6.11 Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, 40 CFR 60 Subpart TTTTa.

On May 9, 2024, the U.S. EPA published a final rule establishing greenhouse gas standards and guidelines for new and reconstructed stationary combustion turbine electric generating units under 40 CFR 60, Subpart TTTTa. New stationary combustion turbines that commence construction or reconstruction after May 23, 2023 and meet the relevant applicability criteria will be subject to 40 CFR 60, subpart TTTTa.

For new and reconstructed fossil fuel-fired combustion turbines, the final rule creates three subcategories based on the function the combustion turbine serves. In accordance with 40 CFR § 60.5580a:

> *Low load combustion turbine* means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.
>
> *Intermediate load combustion turbine* means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.
>
> *Base load combustion turbine* means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

And in accordance with 40 CFR § 60.5580a, *Potential electric output* means:

> *Potential electric output* means the base load rating design efficiency at the maximum electric production rate (*e.g.*, CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.*, a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

For these CTs, the *Potential electric output would be:*

$$Potential\ electric\ output = (0.372)\left(\frac{3{,}279\ \text{mmBtu}}{\text{hr}}\right)\left(\frac{10^6\ \text{Btu}}{\text{mmBtu}}\right)\left(\frac{\text{kWh}}{3{,}413\ \text{Btu}}\right)\left(\frac{\text{MWh}}{1{,}000\ \text{kWh}}\right)\left(\frac{8{,}760\ \text{hr}}{\text{year}}\right)$$

$$Potential\ electric\ output = 3{,}130{,}777\ \text{MWh}$$

APS will comply with the requirements of Subpart TTTTa in accordance with the applicable emission limit in the following Table 1 to Subpart TTTTa which will depend on whether these CTs are operated as low load or intermediate load combustion turbines. Please note that APS will not operate these CTs as base load combustion turbines as that term is defined in Subpart TTTTa.

On June 17, 2025, the U.S. EPA published a proposed rule to repeal all GHG emissions standards for fossil fuel-fired power plants. The EPA is proposing that the Clean Air Act (CAA) requires it to make a finding that GHG emissions from fossil fuel-fired power plants contribute significantly to dangerous air pollution, as a predicate to regulating GHG emissions from those plants. The EPA is further proposing to make a finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution. The EPA is also proposing, as an alternative, to repeal the emission standards under Subpart TTTTa that includes the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines.

Table 1 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[NOTE: NUMERICAL VALUES OF 1,000 OR GREATER HAVE A MINIMUM OF 3 SIGNIFICANT FIGURES AND NUMERICAL VALUES OF LESS THAN 1,000 HAVE A MINIMUM OF 2 SIGNIFICANT FIGURES]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a. For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

Chapter 7. Proposed Permit Conditions and Emission Limits.

With this Class I / Title V significant permit revision application, Arizona Public Service (APS) requests the following permit conditions and emission limits be incorporated into a significant revision of Class I Permit No. V20692 for the construction and operation of the Simple Cycle CT Expansion Project.

7.1 Proposed Facility-wide Synthetic Minor Limits.

From Table 6-1, the unrestricted potential emissions for all PSD regulated pollutants ***except*** CO and NO_x emissions for the entire Saguaro Power Plant, including the proposed new emissions units, are less than the major source threshold of 250 tons per year. Therefore, to limit all PSD regulated pollutants for the entire facility, including the new emissions units, below the major source threshold, synthetic minor emission limits are only required for CO and NO_x emissions. Furthermore, because the combined maximum potential emissions CO and NO_x emissions for all of the other emissions units except the CTs is less than 8 tons per year for each pollutant, restricting the potential emissions for the combustion turbine units CT1, CT2, CT3, CT4, and CT5 ***combined*** to less than 240 tons per year will ensure that the total potential emissions for the entire facility are limited to less than 250 tons per year.

7.1.1 Carbon Monoxide (CO) Facility PSD Synthetic Minor Emission Limit.

1. Carbon Monoxide (CO) PSD Synthetic Minor Emission Limit for CT1, CT2, CT3, CT4, and CT5 combined.

A. CO emissions from combustion turbines CT1, CT2, CT3, CT4, and CT5 combined may not exceed 240 tons per year based on a 12-month average. NOTE: The unrestricted potential CO emissions for all emissions units ***except*** the combustion turbines is less than 8.0 tons per year. Therefore, this limit for the combustion turbines will limit the total facility-wide potential CO emissions to less than 248 tons per year.

B. The permittee shall install, certify, operate, and maintain a natural gas fuel flow meter and a continuous emissions monitoring system for CO emissions (CO CEMS) and a diluent gas (O_2 or CO_2) on combustion turbine units CT3, CT4, and CT5, for determining CO mass emissions during all periods of operation, including startup and shutdown. The CO CEMS shall be installed in accordance with the requirements of 40 CFR Part 60, Appendix B, Performance Specification 4. The diluent gas CEMS (O_2 or CO_2) shall be installed in accordance with the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3 or the performance specifications in 40 CFR Part 75, Appendices A to I.

i. Permittee shall conduct an initial CO CEMS evaluation and subsequent annual evaluations in accord with 40 CFR Part 60, Appendix B, Performance Specification 4 or 4A.

ii. Permittee shall follow the quality assurance procedures in Procedure 1 of 40 CFR Part 60 Appendix F for the CO CEMS. The procedures include daily calibration drift and quarterly accuracy determinations.

iii. Permittee shall evaluate the CO CEMS daily when operating and semi-annually as specified in Appendix A of this permit.

iv. Permittee shall obtain at least two data points per hour in order to calculate a valid 1-hour arithmetic average and complete at least one cycle of operation (sampling, analyzing and data recording) for each 15-minute period of operation.

v. Permittee shall obtain 1-hour averages for 75 percent of the operating hours per day for 90 percent of the operating days per calendar quarter.

vi. If the Permittee does not obtain the minimum data required in paragraph "iv" of this section, all valid data from the CO CEMS must be used in calculating emissions concentrations.

vii. Permittee shall monitor and record daily emissions of CO from the CTs, shall total and record those daily emissions on a calendar-month basis and shall maintain and record a rolling annual average of emissions, rolled on a calendar-month basis. In the event that CEMS data is unavailable due to monitoring equipment malfunction, Permittee may use Part 75 data substitution methodology to define the missing data.

C. For combustion turbine units CT1 and CT2, the permittee shall monitor and record the natural gas fuel flow and calculate the mass of CO emissions using the following methods.

i. Permittee shall maintain records of the type and quantity of fuel usage in the turbines. As long as the total heat input to each combustion turbine units CT1 and/or CT2 is less than 822,500 mmBtu over the preceding 12-month period, then for purposes of monitoring emissions, Permittee may utilize the following method:

$$\text{CO Emissions} = \text{HI} \times \frac{0.082 \text{ lb CO}}{\text{mmBtu}} \times \frac{\text{ton CO}}{2{,}000 \text{ lb CO}}$$

Where, CO Emissions = Mass of CO emissions, ton/month

HI = Heat input to CT1 or CT2, mmBtu/month

0.082 lb/mmBtu = CO emission factor for uncontrolled, natural gas-fired combustion turbines from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, Table 3.1-1.

ii. If the total heat input to either combustion turbine units CT1 and/or CT2 exceeds 822,500 mmBtu over the preceding 12-month period, Permittee shall conduct emission testing for CO emissions from that unit within 90 days triggering the testing requirement, or such longer period as the Control Officer may allow upon a showing of cause. Permittee shall conduct subsequent emission testing for CO emissions from CT1 and/or CT2 at least

once every 5 years. CO emissions shall be measured in accordance with 40 CFR Part 60, App. A, Ref. Method 10.

CO emissions shall be calculated using the following equation:

$$\text{CO Emissions} = \text{HI} \times \text{ER} \times \frac{\text{ton CO}}{2{,}000\ \text{lb CO}}$$

Where, NO_x Emissions = Mass of NO_x emissions, ton/month

HI = Heat input to CT1 or CT2, mmBtu/month

ER = CO emission rate from the most recent performance test, lb/mmBtu

D. Within 30 days of the end of each calendar month, the permittee shall determine the total monthly CO emissions for each of CT1, CT2, CT3, CT4, and CT5 in tons/month.

E. Within 30 days of the end of each calendar month, the permittee shall determine the total monthly CO emissions for CT1, CT2, CT3, CT4, and CT5 combined in tons/month.

F. Within 30 days of the end of each calendar month, the permittee shall determine the total annual CO emissions in the previous 12-month period for CT1, CT2, CT3, CT4, and CT5 combined in tons per year.

7.1.2 Nitrogen Oxides (NO_x) PSD Synthetic Minor Emission Limit.

2. Nitrogen Oxides (NO_x) PSD Synthetic Minor Emission Limit for CT1, CT2, CT3, CT4, and CT5.

A. NO_x emissions from combustion turbines CT1, CT2, CT3, CT4, and CT5 combined may not exceed 240 tons per year based on a 12-month average. NOTE: The combined, unrestricted potential NO_x emissions for all existing emissions units ***except*** the combustion turbines is less than 8.0 tons per year. Therefore, this limit for the combustion turbines will limit the total facility-wide potential NO_x emissions to less than 248 tons per year.

B. The permittee shall install, certify, operate, and maintain a continuous emissions monitoring system for NO_x emissions and a diluent gas (O_2 or CO_2) on combustion turbine units CT3, CT4, and CT5 for determining NO_x mass emissions (NO_x CEMS) during all periods of operation, including startup and shutdown. The NO_x CEMS, including the diluent gas CEMS (O_2 or CO_2) shall be certified, operated, and maintained in accordance with the requirements in 40 CFR Part 75, Appendices A to I.

C. For combustion turbine units CT1 and CT2, the permittee shall monitor and record the natural gas fuel flow and calculate the monthly mass of NO_x emissions using the following methods.

i. Permittee shall maintain records of the type and quantity of fuel usage in the turbines. As long as the total heat input to each combustion turbine units CT1 and/or CT2 is less than 822,500 mmBtu over the preceding 12-month period, then for purposes of monitoring emissions, Permittee may utilize the following method:

$$NO_x \text{Emissions} = HI \times \frac{0.32 \text{ lb } NO_x}{\text{mmBtu}} \times \frac{\text{ton } NO_x}{2{,}000 \text{ lb } NO_x}$$

Where, NO_x Emissions = Mass of NO_x emissions, ton/month

HI = Heat input to CT1 or CT2, mmBtu/month

0.32 lb/mmBtu = NO_x emission factor for uncontrolled, natural gas-fired combustion turbines from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, Table 3.1-1.

i. If the total heat input to either combustion turbine units CT1 and/or CT2 exceeds 822,500 mmBtu over the preceding 12-month period, Permittee shall conduct emission testing for NO_x emissions from that unit within 90 days triggering the testing requirement, or such longer period as the Control Officer may allow upon a showing of cause. Permittee shall conduct subsequent emission testing for NO_x emissions from CT1 and/or CT2 at least once every 5 years. CO emissions shall be measured in accordance with 40 CFR Part 60, App. A, Ref. Method 10.

NO_x emissions shall be calculated using the following equation:

$$NO_x \text{ Emissions} = HI \times ER \times \frac{\text{ton } NO_x}{2{,}000 \text{ lb } NO_x}$$

Where, NO_x Emissions = Mass of NO_x emissions, ton/month

HI = Heat input to CT1 or CT2, mmBtu/month

ER = NO_x emission rate from the most recent performance test, lb/mmBtu

D. Permittee shall conduct emission testing for NO_x emissions from CT1 and CT2 within 90 days of permit issuance. Permittee shall conduct subsequent emission testing for CO emissions from CT1 and CT2 at least once every 5 years. CO emissions shall be measured in accordance with 40 CFR Part 60, App. A, Ref. Method 7E or 20.

E. Within 30 days of the end of each calendar month, the permittee shall determine the total monthly NO_x emissions for each of CT1, CT2, CT3, CT4, and CT5 in tons/month.

F. Within 30 days of the end of each calendar month, the permittee shall determine the total monthly NO_x emissions for CT1, CT2, CT3, CT4, and CT5 combined in tons/month.

G. Within 30 days of the end of each calendar month, the permittee shall determine the total annual NO_x emissions in the previous 12-month period for CT1, CT2, CT3, CT4, and CT5 combined in tons per year.

7.2 Proposed Requirements for the New Combustion Turbine Units CT4 and CT5.

1. Combustion Turbine Units CT4 and CT5 System Design and Operating Requirements.

   a. Each CT shall utilize a dry low NO_x combustion system and a selective catalytic reduction system (SCR) for the control of NO_x emissions.

   b. Each CT shall utilize an oxidation catalyst system for the control of CO, VOC, and hazardous air pollutant (HAP) emissions.

   c. Each CT shall exhaust to the atmosphere through a stack not greater than 31 feet in diameter, nor less than 165 feet in height;

   d. Each stack shall be equipped with such platforms and sampling ports as may be required to fulfill the testing and monitoring requirements set forth below;

   e. Separate fuel-flow meters shall be installed and operated on each respective CT.

   f. Include NO_x and CO continuous emissions monitoring systems (CEMS) as defined in the compliance provisions of this permit.

   g. The total heat input to each CT4 and CT5 may not exceed 12,924,700 mmBtu in any rolling 12-month period.

   h. The total number of startup and shutdown events for each CT4 and CT5 may not exceed 365 combined startup and shutdown events in any rolling 12-month period.

2. Definitions.

   a. “Startup” for CT4 and CT5 is defined as the period beginning with the ignition of fuel and ending 30 minutes later.

   b. “Shutdown” for CT4 and CT5 is defined as the period beginning with the initiation of the gas turbine shutdown sequence and lasting until fuel combustion has ceased.

   c. “Malfunction” is defined as any sudden and unavoidable failure of air pollution control equipment, process equipment or a process to operate in a normal and usual manner, but does not include failures that are caused by poor maintenance, careless operation or any other upset condition or equipment breakdown which could have been prevented by the exercise of reasonable care.

3. The Permittee shall not cause to be discharged into the atmosphere from the Units CT4 or CT5 combustion turbine systems carbon monoxide (CO) emissions in excess of:

   a. 1,500 pounds per hour during all periods of operation including periods of start-up, warm-up, shut-down, and malfunction.

   b. The permittee shall install, certify, operate, and maintain a continuous emissions monitoring system for CO emissions (CO CEMS) and a diluent gas (O_2 or CO_2) on combustion turbine units CT4 and CT5 for determining CO mass emissions. The CO CEMS shall be installed in

accordance with the requirements of 40 CFR Part 60, Appendix B, Performance Specification 6. The diluent gas CEMS (O_2 or CO_2) shall be installed in accordance with the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3 or the performance specifications in 40 CFR Part 75, Appendices A to I.

4. The Permittee shall not cause to be discharged into the atmosphere from the Units CT4 or CT5 combustion turbine systems nitrogen oxides (NO_x) emissions in excess of:

   a. *Standards of Performance for Stationary Combustion Turbines*, 40 CFR 60, Subpart KKKKa:

      i. 9 ppm at 15 percent O_2 (0.033 lb NO_x/mmBtu) based on a 4-hour rolling average, ***AND*** 96 ppm at 15 percent O_2 (0.35 lb NO_x/mmBtu) when operating at less than 70 percent of base load rating, or when operating at temperatures less than 0 °F, OR

      ii. 0.37 lb NO_x/MWh based on a 30-operating day rolling average.

   b. 302 pounds per hour during all periods of operation including periods of start-up, warm-up, shut-down, and malfunction.

   c. The permittee shall install, certify, operate, and maintain a continuous emissions monitoring system for NO_x emissions and a diluent gas (O_2 or CO_2) on combustion turbine units CT4 and CT5 for determining NO_x mass emissions (NO_x CEMS). The NO_x CEMS, including the diluent gas CEMS (O_2 or CO_2) shall be certified, operated, and maintained in accordance with the requirements in 40 CFR Part 75, Appendices A to I.

5. The Permittee shall not cause to be discharged into the atmosphere from the Units CT4 or CT5 combustion turbine systems particulate matter (PM), PM_{10}, or $PM_{2.5}$ emissions in excess of 25.0 pounds per hour.

6. The Permittee shall not cause to be discharged into the atmosphere from the Units CT4 or CT5 combustion turbine systems volatile organic compound (VOC) emissions in excess of 8.4 pounds per hour.

7. Permittee may only utilize pipeline natural gas as fuel, provided Permittee shall not burn natural gas having a hydrogen sulfide content in excess of 1 grain 100 scf, or a total sulfur content in excess of 20 grains/100 scf. For compliance reporting and emission inventory purposes, permittee shall quantify SO_2 emissions using an SO_2 emission rate of 0.0006 lbs/mmBtu.

8. The Permittee shall not cause to be discharged into the atmosphere from the Units CT4 or CT5 combustion turbine systems visible emissions in excess of 40% opacity as measured by Reference Method 9.

9. The permittee shall comply with the applicable carbon dioxide (CO_2) emission standard for in 40 CFR 60, Subpart TTTTa.

a. For low load combustion turbine operation, CO_2 emissions may not exceed 120 to 160 lb CO_2/MMBtu of heat input.

b. For intermediate load combustion turbine operation, CO_2 emissions may not exceed 1,170 lb CO_2/MWh of gross energy output; or 1,190 lb CO_2/MWh of net energy output, based on a 12-month average.

c. The Permittee shall operate combustion turbine Units CT4 and CT5 such that each unit is not subject to the requirements for Base Load Combustion Turbines under 40 CFR 60.5520a(a) and Table 1 to Subpart TTTTa of Part 60.

10. Initial Performance Testing.

a. Within 60 days after achieving maximum production rate of each CT (CT13-CT24), but no later than 180 days after the initial start-up of the CTs, Permittee shall conduct performance tests using standard test methods approved by the EPA (40 CFR Part 60) as specified below. If any change to the test methods and procedures specified in this permit condition are approved, the Permittee shall submit an application to revise the permit to reflect the approved alternate test methods. These tests shall be performed at a maximum heat input capacity available on the day of testing. The continuous monitoring systems required by this permit shall be operating prior to conducting the performance tests. The performance tests shall address:

i. Nitrogen oxides (NO_x) emissions: Ref. Part 60, App. A, Ref. Method 7E or use NOX CEMS RATA as the initial NO_X performance test (NSPS Subpart KKKK, 40 CFR Part §60.4400.(b).(5), §60.4405)

ii. Carbon monoxide (CO) emissions: Ref. Part 60, App. A, Ref. Method 10, or use CO CEMS RATA

iii. Particulate matter emissions (PM_{10}, $PM_{2.5}$): Ref. Part 60, App. A, Ref. Method 5 or 201A and (condensable PM_{10}), Ref. Method 202

iv. Volatile organic compound emissions (VOC): Ref. Part 60, App. A-7, Ref. Method 25a

v. Opacity: Ref. Part 60, App. A, Ref. Method 9, 40 CFR §60.11

11. Test Protocol

a. Test protocols for all the tests shall be submitted to the District at least thirty (30) days prior to the test.

12. Performance Test Notice

a. Notice of any performance test required by this permit shall be submitted to the District at least thirty days (30) days prior to conducting the test.

13. Test Report

a. A copy of each test report shall be submitted to the District for approval within forty-five (45) days after the test. In addition to any other information required under this permit, the test report shall specifically define that the following pollutants meet the emission limitations specified in §Section 5.C of this permit:

i. CO emission rates, defined as a function of heat input and as a concentration in parts per million on a dry volume basis, corrected to 15% O_2.

ii. NO_x emissions rates, defined as function of heat input and as a concentration in parts per million on a dry volume basis, corrected to 15% O_2.

iii. PM_{10} emission rates, defined as a function of heat input

iv. $PM_{2.5}$ emission rates, defined as a function of heat input

v. VOC emission rates, defined as a function of heat input

14. Subsequent Performance Tests (CT4 and CT5) [40 CFR 60.8, Code §§3-1-160 & 3-1-170, R18-2-311, R18-2-312)

a. Permittee shall conduct performance tests, using standard test methods approved by the EPA (40 CFR Part 60) as specified below. If any change to the test methods and procedures specified in this permit condition are approved, the Permittee shall submit an application to revise the permit to reflect the approved alternate test methods. These tests shall be performed at a maximum heat input capacity available at the day of testing. The continuous monitoring systems required by this permit shall be operating prior to conducting the performance tests. The performance tests shall address:

i. Nitrogen oxides (NO_x) emissions Ref. Part 60, App. A, Ref. Method 7E or 20 or Permittee may use NO_x CEMS RATA to demonstrate compliance with the NO_x emission limits (NSPS Subpart KKKKa).

ii. Carbon monoxide (CO) emissions Ref. Part 60, App. A, Ref. Method 10

iii. Particulate matter emissions (filterable PM_{10},$PM_{2.5}$) Ref. Part 60, App. A, Ref. Method 5 or 201A and (condensable) PM_{10}) Method 202.

iv. Volatile organic compounds (VOCs) emissions Ref. Part 60, App. A, Ref. Method 25a

15. Test Protocol

a. A test plan protocol for each test shall be submitted to the District at least thirty (30) days before the testing.

16. Performance Test Notices

a. Notice of any performance test required by this permit shall be submitted to the District at least thirty (30) days prior to conducting the test.

17. Test Reports

a. A copy of each test report shall be submitted to the District for approval within forty-five (45) days after the test. In addition to any other information required under this permit, test report for all mandatory tests shall specifically define:

   i. CO emission rates, defined as a function of heat input and as a concentration in parts per million on a dry volume basis, corrected to 15% O_2.

   ii. NO_x emissions rates, defined as function of heat input and as a concentration in parts per million on a dry volume basis, corrected to 15% O_2.

   iii. PM_{10} emission rates, defined as a function of heat input

   iv. $PM_{2.5}$ emission rates, defined as a function of heat input

   v. VOC emission rates, defined as a function of heat input

18. Recurring Testing Cycle

   a. Except as provided below, Performance tests shall be repeated within 5 years of the previous performance tests.

   b. Subsequent CO performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). If the Permittee elects to demonstrate compliance using a CO CEMS, no subsequent performance tests are required, and RATA shall be performed at the frequency required by 40 CFR Part 60, Appendix F, as applicable.

   c. Subsequent NO_x performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). If the Permittee elects to demonstrate compliance using the NO_x-diluent CEMS, no subsequent performance tests are required, and RATA shall be performed at the frequency required by 40 CFR Part 75, Appendix B, Sections 2.3.1.1 or 2.3.1.2 as applicable.

   d. Subsequent SO_2 tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). One of the three methodologies described in Subpart KKKKa can be used to conduct the performance tests.

7.3 Proposed Requirements for the Natural Gas-Fired Natural Gas Heater H1.

1. The heater manufacturer's design carbon monoxide (CO) emissions rate may not exceed 50 ppmvd corrected to 3 percent oxygen.

2. The heater manufacturer's design nitrogen oxides (NO_x) emissions rate may not exceed 30 ppmvd corrected to 3 percent oxygen.

3. Permittee is allowed to burn only pipeline quality natural gas as the primary fuel.

7.4 Proposed Requirements for the Mechanical Draft Cooling Towers MDCT1 and MDCT2.

1. Each mechanical draft cooling tower shall be equipped with a mist elimination system designed for a maximum drift loss of no more than 0.005%.

2. The maximum total dissolved solids (TDS) of the cooling tower circulating water may not exceed 2,450 parts per million (ppm) on a weight basis.

7.5 Proposed Requirements for the Diesel Emergency Fire Pump.

1. This engine shall be certified to meet the following standards in the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, 40 CFR 60, Subpart IIII.

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
510 Hp Fire Pump	2009 +	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)

2. The emergency fire pump engine may not be operated for more than 200 hours per year.

7.6 Proposed Revisions to the Existing Permit Conditions for Combustion Turbine Unit CT3.

With this application, APS proposes the removal of the PSD synthetic minor caps for CT3. These limitations may be replaced with the existing facility CO and NO_x emission caps proposed in this application. The proposed deletions are shown in ~~redline strikeout~~.

~~E. Emission Cap - Frame 7EA Combustion Turbine~~

Emissions from the Frame 7EA combustion turbine generator shall not exceed the following NO_x and CO caps:

1. NOx Cap

[Federally enforceable provision, pursuant to Code §3-1-084 (8/11/94)] (Code §3-1-081.A)

The NOx cap shall be 39 tpy.

2. CO Cap

[Federally enforceable provision, pursuant to Code §3-1-084 (8/11/94)] (Code §3-1-081.A)

The CO cap shall initially be set at 97.5 tpy, but may be adjusted downward to reflect the lowest of the allowable emission rates defined below:

a. Provided accuracy testing under 40 CFR Part 60, Appendix F shows that the CO CEMs maintain no more than 2.5% error, the allowable rolling 12-month average of CO emissions that includes the date of the accuracy test shall not exceed 97.5 tpy.

b. If accuracy testing under 40 CFR Part 60 shows that the CO CEMs maintain a maximum 5% error, the allowable rolling 12-month average of CO emissions that includes the date of that RATA test shall not exceed 95 tpy;

c. If accuracy testing under 40 CFR Part 60 shows that the CO CEMs exceeds 5% error, the allowable rolling 12-month average of CO emissions that includes the date of that RATA test shall not exceed 90 tpy.

3. Averaging period

[Federally enforceable provision, pursuant to Code §3-1-084 (8/11/94)] (Code §3-1-081.A)

Compliance with all caps for the 7EA unit shall be assessed on the basis of an annual average, rolled monthly, on a calendar-month basis.

Chapter 8. Ambient Air Quality Assessment.

Appendix B of this application includes the ambient air quality assessment modeling protocol and report. The report demonstrates that for the minor-NSR triggered pollutants PM_{10} and CO, the maximum Project impacts are below the Significant Impact Levels (SILs). For the minor-NSR triggered pollutants $PM_{2.5}$ and NO_2, the maximum Project impacts added to the background air quality concentrations are below the NAAQS. Therefore, the Project will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS). In addition, a Learning Sites air toxics modeling analysis demonstrates that all air toxics impacts are below the acute and chronic Ambient Air Concentration (ACC) thresholds.

Appendix A.

Pinal County Air Quality Department Forms.

Pinal County Air Quality Control District

P.O. Box 987 – Florence, AZ 85132 P-(520) 866-6929 F-(520) 866-6967

PINAL COUNTY
WIDE OPEN OPPORTUNITY

Permit Application

(As required by A.R.S. §49-480, and Chapter 3, Article I, Pinal County Air Quality Control District Code of Regulations)

1. Permit to be issued to: Arizona Public Service Company
   (Name and legal status (e.g. corporation or proprietorship) or organization that is to receive permit)
2. Mailing Address: 400 N 5th St, Mail Station 9303
   City: Phoenix State: AZ Zip: 85004
   Billing Address (if different from above):
   City: State: Zip:
3. Plant Name (if different from above): Saguaro Power Plant
4. Name(s) of Owner or Operator: Arizona Public Service Company Co
   Phone: 602-371-6767
5. Plant/Site Manager: Kristy Contreras Phone: 480-446-0131 Fax:
6. Contact Person: Hui Chen Phone: 602-250-5146 Fax:
   Email Address: hui.chen@aps.com
7. Equipment/Plant Location or Proposed Location Address: Mile Post Marker 228 at I-10
   City: Red Rock Zip: 85145 Parcel #: 41008003A
   Section/Township/Range: 15/10S/10E
   Latitude/Longitude: 32°33'18"/111°17'57" Elevation:
8. General Nature of Business: Electric Power Generation
   North American Industry Classification System: 4911
9. Type of Organization
   - [x] Corporation — State of Incorporation: Arizona
   - [ ] Arizona Limited Liability
   - [ ] Government Entity — Government Facility Code:
   - [ ] Individual Owner
   - [ ] Partnership
   - [ ] Other (Specify):

1

10. Permit Application Basis: (Check all that apply)
    - ☐ New Source
    - ☒ Permit Revision
    - ☐ Administrative Change
    - ☒ Renewal of Existing Permit
    - ☐ Portable Source
    - ☐ General Permit
    - ☐ Permit Transfer

    For renewal or modification, include existing permit number: V20892.R01

    Date of Commencement of Construction or Modification: ~~Not applicable~~ 4/01/2028

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

11. If necessary to preserve this source's status as a less-than-major source, the undersigned agrees that the permit or this source ***SHOULD*** ☐ ***SHOULD NOT*** ☐ include Federally Enforceable Provisions in accord with Code §3-1-084.

12. The undersigned states and certifies that, based on information and belief formed after reasonable inquiry, the statements and information in this document and supporting materials are true, accurate and complete. To the extent that this application pertains to an assignment of an existing permit, the undersigned further agrees to comply with and accept each and every obligation associated with that existing permit. *Knowingly presenting a false certification constitutes a criminal offense under A.R.S. §13-2704.*

13. The undersigned applicant states that he/she currently has, or at the time construction and/or operation begins will have, legal authority to enter upon and use the premises upon which this source will be operated.

14. Attach a description of the process to be permitted or revised including a list of equipment, capacities, MSDS sheets and anticipated production or throughput.

15. For new sources, an application filing deposit fee must be included with the application.

Kristy Contreras
Signature of Responsible Official of Organization

Kristy Contreras
Typed or Printed Name of Signer

Plant Director
Official Title of Signer

4/13/2026
Date

Appendix B.

Air Quality Modeling Protocol and Report.

AIR MODELING PROTOCOL AND REPORT FOR THE TITLE V PERMIT SIGNIFICANT REVISION APPLICATION FOR THE APS SAGUARO POWER PLANT



Prepared for:
Arizona Public Service
400 North 5th Street
Phoenix, AZ 85004

Prepared by:
RTP Environmental Associates, Inc.
304-A West Millbrook Road
Raleigh, North Carolina 27609

April 2026

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1.0 INTRODUCTION

This document is a combined air quality modeling protocol and report for the proposed Arizona Public Service (APS) Saguaro Power Plant (SPP) expansion project (the Project). APS is planning to add two natural gas-fired simple-cycle combustion turbines (CTs) and auxiliary support equipment at SPP. APS has submitted a Title V Permit Significant Revision Application (herein referred to as the Permit Application) that describes the proposed Project, presents emissions calculations, and includes a regulatory applicability analysis that demonstrates that the SPP, including the new emission units, will be classified as a minor source under the New Source Review (NSR) regulations. The proposed potential emissions of the new emission units will be above the minor-NSR permitting exemption thresholds in Arizona Administrative Code (AAC) R18-2-101(101) for the pollutants CO, NO_2, PM_{10}, and $PM_{2.5}$, therefore minor-NSR review is triggered for these pollutants.

Projects subject to the minor-NSR program shall comply with one of the following requirements for the minor-NSR triggered pollutants: a) implement Reasonably Available Control Technology (RACT), or b) perform an ambient air quality assessment that demonstrates emissions from the project will not interfere with attainment or maintenance of a National Ambient Air Quality Standard (NAAQS). Even though the proposed CTs are natural gas-fired and equipped with pollution control systems that would meet RACT requirements, APS has elected to perform an air quality modeling analysis for the minor-NSR triggered pollutants.

The air quality modeling procedures conform with requirements in the U.S. Environmental Protection Agency's (EPA) Guideline on Air Quality Models (40 CFR Part 51 Appendix W), the Arizona Department of Environmental Quality (ADEQ) Air Dispersion Modeling Guidelines for Arizona Air Quality Permits, and ADEQ's Minor NSR Guidance document (December 3, 2015).

2.0 PROJECT DESCRIPTION

The existing SPP consists of three simple-cycle CTs, three lube oil cooling towers, and an emergency generator for the Battery Energy Storage System (BESS). Combustion turbine units CT1 and CT2 are Westinghouse Model 501AA natural gas-fired simple cycle CTs and CT3 is a General Electric Model 7EA natural gas-fired simple cycle CT. The BESS facility includes a 755 horsepower (578 kW) diesel emergency generator. SPP operates under Pinal County Operation Permit #V20692.R01.

APS is planning to add two natural gas-fired, simple cycle CT electric generating units, two lube oil cooling towers, a natural gas dew point conditioning heater, and a diesel fire pump. The Permit Application presents detailed information and emission calculations for this new equipment.

3.0 SITE DESCRIPTION

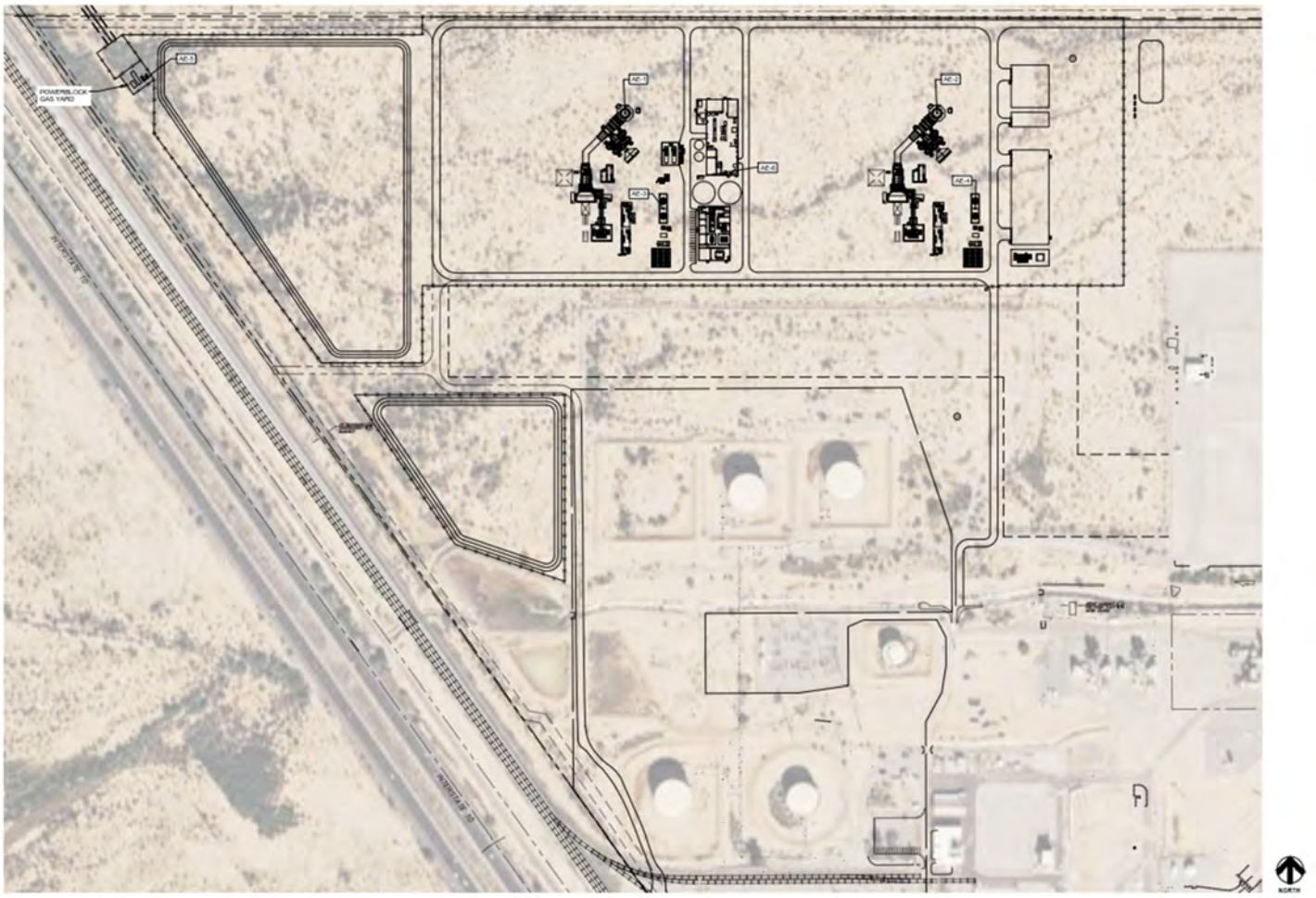
The SPP is in Pinal County, located approximately 37 miles northwest of Tucson, Arizona. The approximate Universal Transverse Mercator (UTM) coordinates of the facility are 472,100 meters east and 3,601,900 meters north (UTM Zone 12, NAD 83). The facility is approximately 584 m (1,919 ft) above mean sea level. Figure 1 shows the general location of the facility. Figure 2 shows the facility layout.

The facility is located in an area that is classified as attainment or unclassified for all criteria pollutants. The West Pinal PM_{10} nonattainment area (NAA) is located 4 km to the north of SPP, the Rillito PM_{10} NAA is located 6 km to the south of SPP, the West Central Pinal $PM_{2.5}$ NAA is located 60 km to the northwest of SPP, and the Phoenix ozone NAA is located 66 km to the north of SPP.

Figure 1. General Location of the APS Saguaro Power Plant



Figure 2. Layout of the APS Saguaro Power Plant



4.0 MODEL SELECTION AND MODEL INPUT

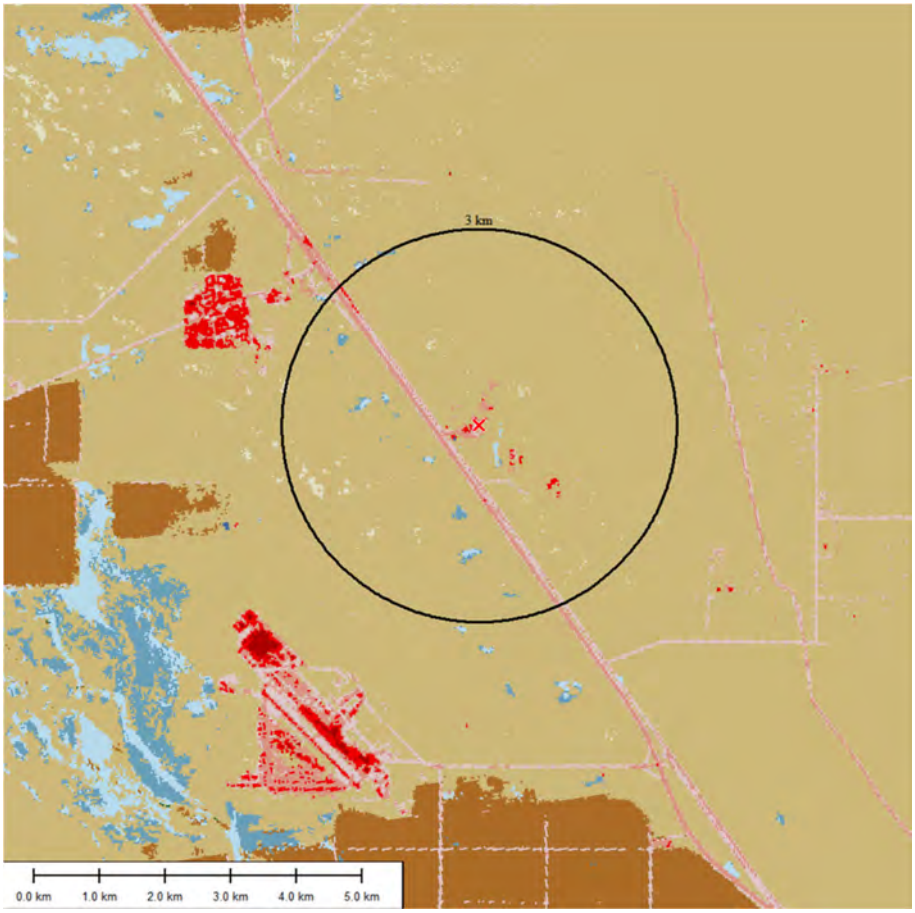
4.1 Model Selection

The latest version of the AMS/EPA Regulatory Model AERMOD was used for the air quality modeling analyses. AERMOD is a gaussian plume dispersion model that is based on boundary layer principles for characterizing atmospheric stability. The model evaluates the non-gaussian vertical behavior of plumes during convective conditions with the probability density function and the superposition of several gaussian plumes. AERMOD is a modeling system with three components: AERMAP is the terrain preprocessor program, AERMET is the meteorological data preprocessor and AERMOD includes the dispersion modeling algorithms. The model also can incorporate building wake effects and calculate concentrations within the cavity recirculation zone. All model options were selected as recommended in the EPA and ADEQ modeling guidelines.

4.2 Control Options and Land Use

AERMOD was run in the regulatory default mode with the default rural dispersion coefficients. The use of rural dispersion coefficients is supported by the Land Use Procedure consistent with subsection 7.2.1.1.b.i of the EPA Modeling Guidelines and Section 5.1 of the AERMOD Implementation Guide. The USGS 2016 National Land Cover Data ("NLCD") within 3km of the site is presented in Figure 3. It was determined that the land use in the vicinity of the facility is predominantly rural as defined by Auer as less than 50% of the area is classified as urban. Only the red and dark red regions in Figure 3, NLCD categories 23 and 24, are considered urban (the airport land use category is also shaded in red).

Figure 3. Land Use within Three Kilometers (3km Radius Shown)



4.3 Source Data

Source Characterization

All of the emission units at SPP were modeled as point sources in AERMOD. The new Project emission units include two new CTs, two lube oil cooling towers, a natural gas dew point conditioning heater, and a diesel fire pump. The existing emission units include three CTs, three cooling towers, and an emergency generator. All source locations will be based upon a NAD83, UTM Zone 12 projection. None of the stacks have horizontal releases or rain caps. Refer to Attachment A for source emission and stack parameter data.

All emission units were modeled at their maximum short-term emission rates for short-term analyses, and annual emission rates for the annual analyses. Because there is an annual NO_X emission limit of 248 tpy that applies to the entire facility, some method of allocating this emission limit amongst the combustion units was needed when performing the annual NO_2 modeling. A very conservative approach (i.e., one that results in higher modeled impacts) was used. The unrestricted annual NO_X emissions for each existing emission unit and all new emission units except CT4-CT5 were modeled, and for CT4-CT5 one half of the 248 tpy emission rate was allocated to each new turbine. This resulted in a total modeled annual NO_X emission rate from the facility of approximately 4,000 tpy, which greatly overstates the synthetic minor restricted NO_X emissions of 248 tpy.

Intermittent Source Characterization

The new Project emission units include an emergency fire pump engine, and the existing emission units include an emergency generator. ADEQ has developed guidance on how to include these intermittent sources in the 1-hr NO_2 NAAQS analysis; these sources are modeled using the annualized average emission rates. However, this intermittent source guidance does not extend to the 24-hr PM_{10} and $PM_{2.5}$ analyses. For those analyses, both of these emergency units were assumed to be tested only during daytime hours between 8am and 5pm, modeled using AERMOD HROFDY emission factors. This conservatively represents a range of testing operations for the emergency units for the PM_{10} and $PM_{2.5}$ analyses.

Good Engineering Practice Stack Height Analysis

A Good Engineering Practice (GEP) stack height evaluation was conducted. None of the proposed stacks exceed the de minimus 65m GEP stack height, therefore all stacks are fully creditable for the modeling analysis.

Building/structure locations and heights were determined from facility plot plans and aerial photos and input to the EPA's Building Profile Input Program (BPIP-PRIME)

computer program to create data file that were input to AERMOD so the model can address any building downwash effects.

4.4 Monitored Background Data

Pursuant to ADEQ Modeling Guidelines and the ADEQ Minor NSR Guidance documents, background pollutant concentrations must be included in NAAQS modeling for minor NSR analyses only if the Project impacts for a specific pollutant are greater than the Significant Impact Levels (SILs). As will be shown later in this report, the only pollutants with Project impacts greater than the applicable SILs are NO_2 and $PM_{2.5}$. Therefore, background data is required for these two pollutants for the minor-NSR NAAQS analysis. However, because a facility-wide NAAQS analysis is also required under the Learning Sites Policy (see Section 5.4 of this protocol/report), background concentrations were also compiled for all other criteria pollutants. Background concentrations are intended to account for sources not explicitly included in the modeling and are added to the modeled concentrations to assess NAAQS compliance.

In Arizona, ambient monitoring is conducted by several governmental agencies, including ADEQ, Pinal County, and Pima County. The latest annual data reports from these agencies were reviewed to determine representative background monitors and compile background concentration data.

The closest NO_2, SO_2, and CO monitors to the SPP are at the Pima County monitoring station #04-019-1028 (Children's Park Ncore station), located approximately 26 miles to the southeast in northern Tucson. This station is a neighborhood scale monitor, and is adequately representative of the air quality in the vicinity of the SPP. The most recent complete 3-year averages of the 98th percentile 1-hr and the annual mean NO_2 concentrations from this site for the period 2022-2024 are 58 and 13 µg/m3, respectively. The corresponding 3-year averages of the 99th percentile 1-hr and the annual mean SO_2 concentrations are 9 and 0.2 µg/m3, respectively. The highest

measured CO concentrations over the same 3-year period are 1,260 µg/m3 for 1-hour averages and 687 µg/m3 for 8-hour averages.

The closest $PM_{2.5}$ monitor to the SPP is the Pima County monitoring station #04-019-1034 (Coachline) located approximately 16 miles to the southeast in northern Tucson. This monitor is a neighborhood scale monitor, and is adequately representative of the air quality in the vicinity of the SPP. The most recent 3-year averages of the 98th percentile 24-hr and the annual mean $PM_{2.5}$ concentrations at this site for 2022-2024 are 21.8 and 5.4 µg/m3, respectively.

The closest PM_{10} monitor to the SPP is the Pima County monitoring station #04-019-1018 (Tangerine) located approximately 15 miles to the southeast in northern Tucson. This monitor is a neighborhood scale monitor, and is adequately representative of the air quality in the vicinity of the SPP. The 3-year average of the 2nd highest yearly 24-hr average values at this site for 2022-2024 is 55 µg/m3.

The closest ozone monitor to the SPP is the Pinal County monitoring station #04-021-3007 (Pinal Air Park) located approximately 3 miles to the southwest. This monitor is a regional scale monitor, and is adequately representative of the air quality in the vicinity of the SPP. The most recent 3-year average MDA8 ozone design concentration for 2022-2024 is 0.067 ppm.

4.5 Receptor Data

Modeled receptors are placed in all areas considered as "ambient air", defined as that portion of the atmosphere, external to buildings, to which the general public has access.

The receptor grid consists of multiple nested Cartesian grids, as well as receptors spaced at 25m intervals along the facility fence lines. The first Cartesian grid extends to approximately 1km from the fences in all directions, with a receptor density of 100 m. The following nested receptor grids include a 5 km grid with 250 m density, a 7 km grid with 500 m density, a 15 km grid with 1000 m density, and a 25 km grid with 2000 m density. In addition, a 100 m space grid was located at the elevated terrain hill

(approximately 675 feet higher than the SPP base elevation) located 6.5 kilometers to the northeast. These receptor grids comply with recommendations in ADEQ's Modeling Guidelines. Figure 4 presents a close-in view of the receptor grid, and Figure 5 presents a larger scale view.

Receptor elevations and hill height scale factors were calculated with AERMAP (version 24142). The USGS 1 arc-second National Elevation Data (NED) were obtained from the USGS. All locations were based upon a NAD83, UTM Zone 12 projection.

4.6 NO_2 Conversion Technique

The Tier 2 Ambient Ratio Method (ARM2) was employed with the EPA recommended minimum and maximum ambient NO_2/NO_X ratios of 0.5 and 0.9, respectively.

Figure 4. APS Saguaro Receptor Grid – Close in View

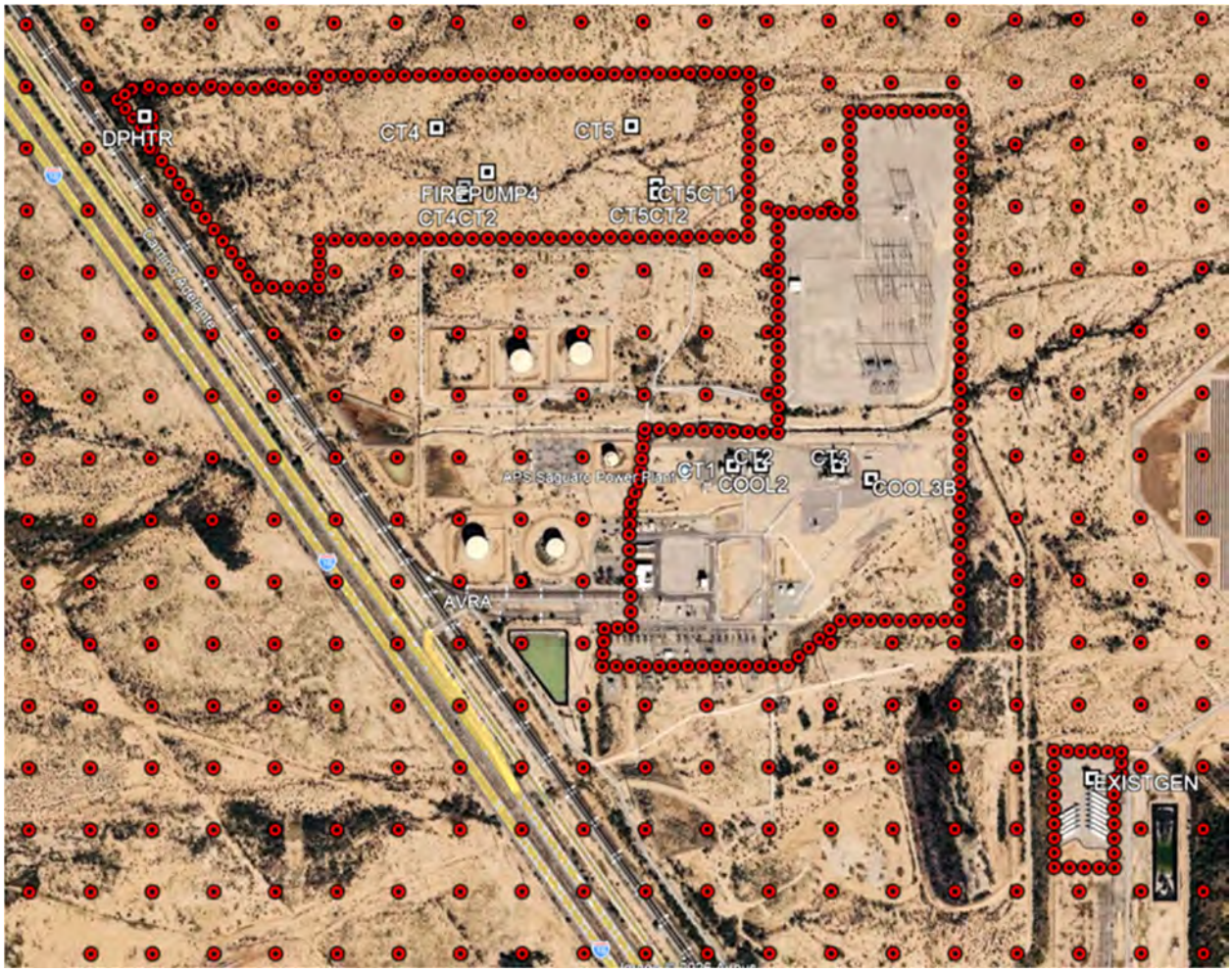
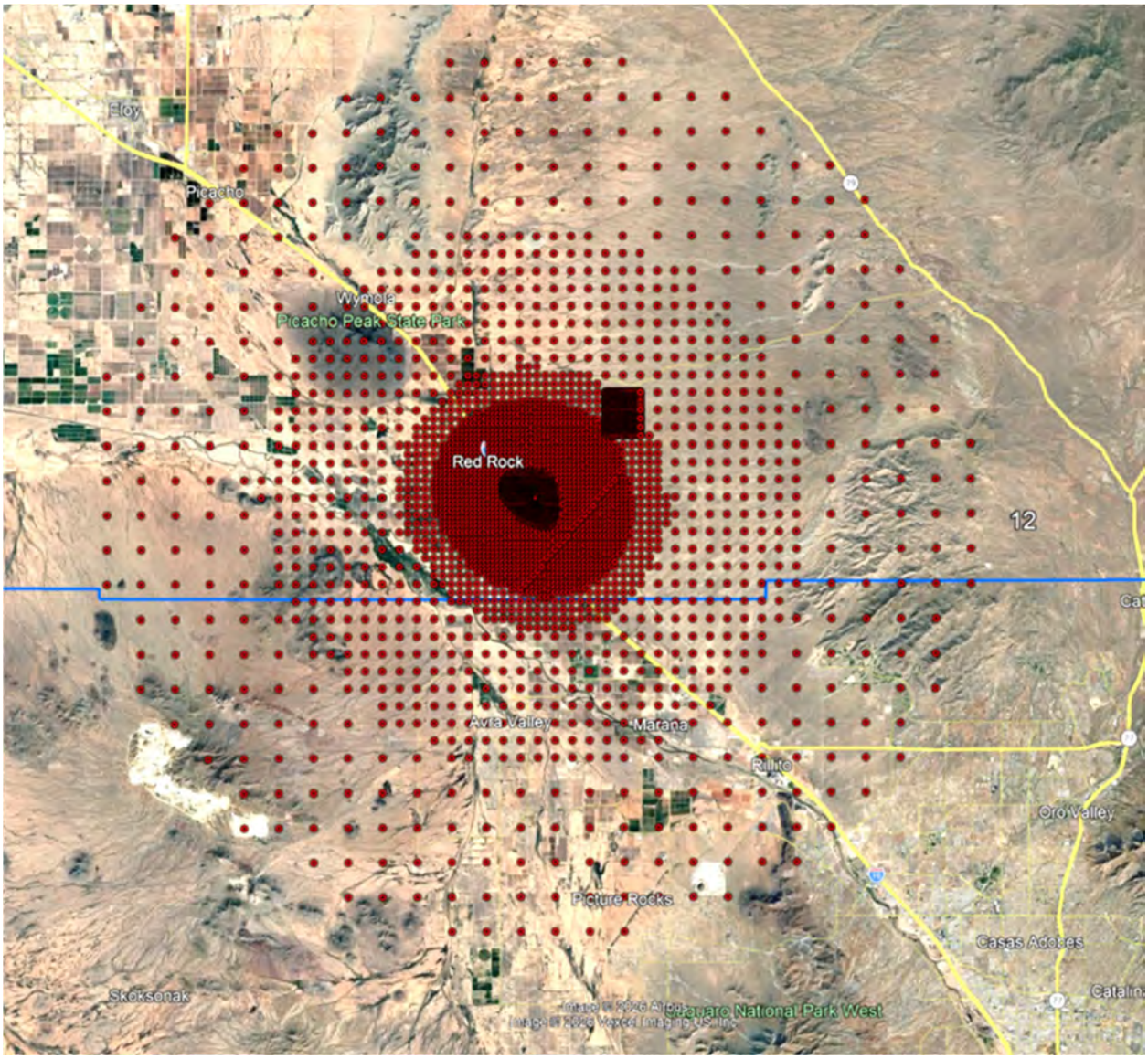


Figure 5. APS Saguaro Receptor Grid



4.7 Meteorological Data

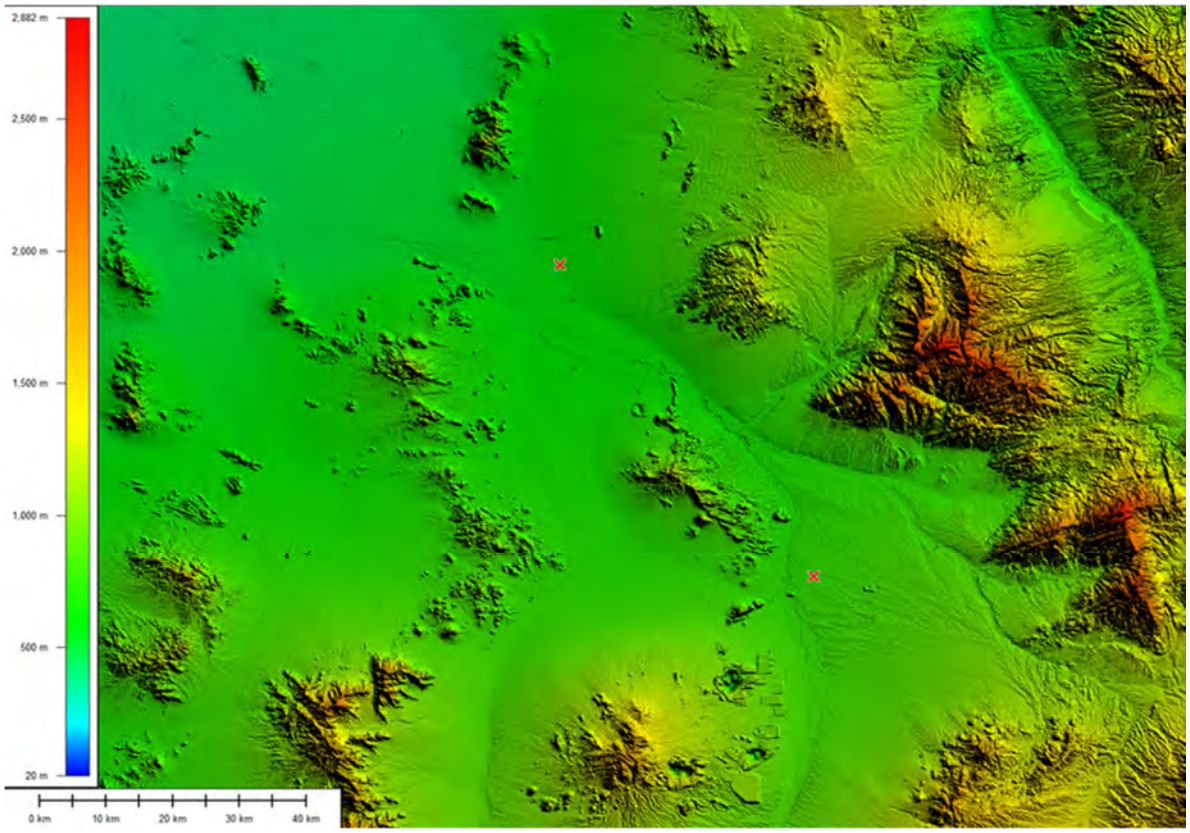
There are four criteria in EPA's Modeling Guideline for assessing whether meteorological data are representative of the study area: 1) proximity of the meteorological station, 2) the complexity of the terrain, 3) the exposure of the meteorological site, and 4) the period of time during which the data are collected.

ADEQ's Tucson airport meteorological data have been evaluated relative to these criteria and determined to be representative of the SPP study area. Tucson airport is the closest National Weather Service Automated Surface Observing System (ASOS) meteorological monitoring station to SPP, located approximately 37 miles to the southeast of the SPP facility. ASOS stations meet rigorous exposure and quality assurance data requirements. Both the Tucson ASOS station and the SPP site are located in open, flat valley floors approximately 1,900 to 2,600 feet in elevation. Both locations have mountain ranges to the east and west that range up to 7,500 feet in elevation. Figure 6 presents the topography at the SPP (upper left mark) and Tucson ASOS station (lower right mark), showing similar topography and valley orientations at the two locations. Figure 7 presents the wind rose for the period 2020-2024 at the Tucson ASOS station. This wind rose shows the expected northwest/southeast wind flow patterns given the orientation of the valley and the Santa Cruz River.

ADEQ has made available state-wide prognostic meteorological data for 2013 – 2015 (12km WRF simulations and MMIF processed data for each 12km grid cell), which can be used to compare wind flow patterns at various locations. Figure 8 presents the wind roses from the grid cells closest to SPP and the Tucson ASOS station. These two WRF wind roses show good agreement between the two locations, further supporting the use of the Tucson ASOS data for modeling of the SPP.

In summary, the Tucson ASOS 5-year data set meets the criteria in EPA's Modeling Guideline and is adequately representative of the meteorological conditions experienced at the SPP project site.

Figure 6. Topography at SPP and Met Station



Note: The SPP is located at the upper mark and the Tucson airport meteological station is located at the lower mark.

Figure 7. Tucson Windrose Data (2020-2024)

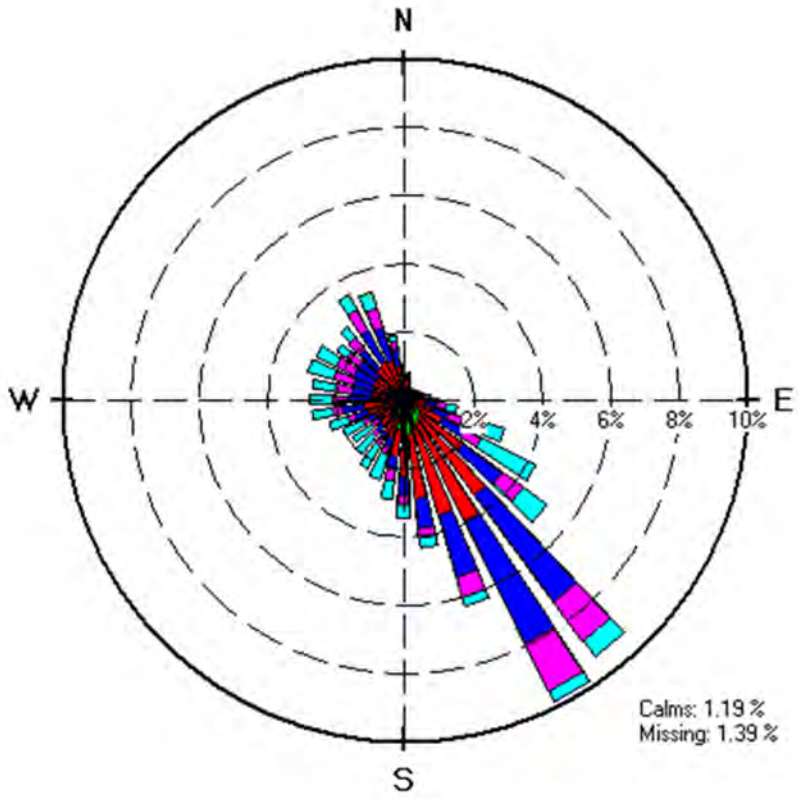
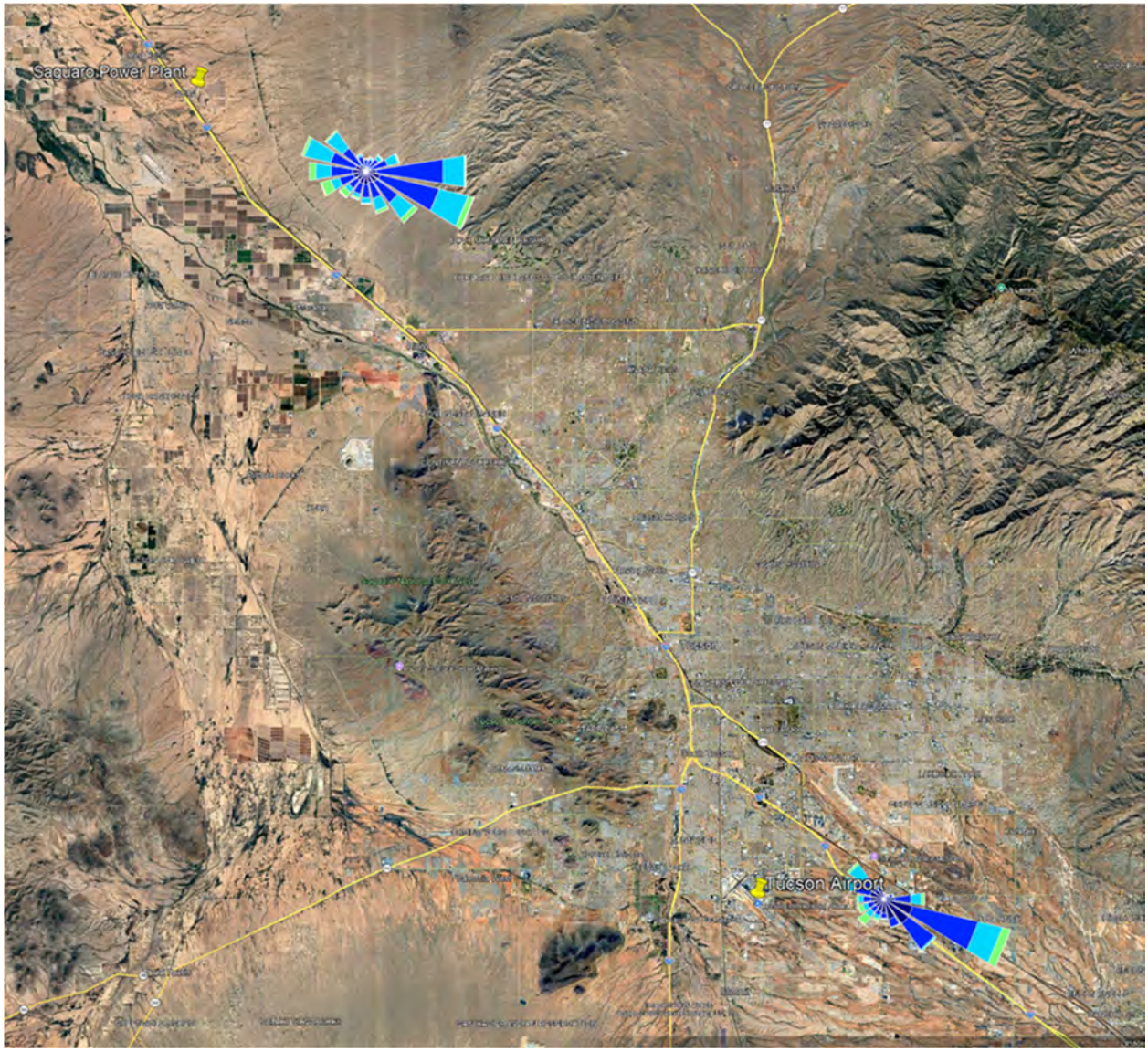


Figure 8. Nearby WRF Wind Rose Data (2013-2015)



Note: The upper wind rose is from the closest WRF grid cell to SPP, and the lower wind rose is the grid cell closest to the Tucson ASOS meteorological station.

5.0 MODELING METHODOLOGY

5.1 Pollutants Subject to Review

The criteria pollutants with emissions in excess of the minor-NSR permitting thresholds that were evaluated in the AERMOD modeling analysis are CO, NO_2, PM_{10}, and $PM_{2.5}$. Note that because the Project is subject to the Learning Sites Policy, AERMOD modeling was also conducted for SO_2 and air toxics.

5.2 Load/Operating Conditions and Facility Design

The CT4-CT5 turbine emission rates and stack parameters vary with operating load and ambient temperature. A load screening analysis was therefore performed to determine the operating conditions that result in the highest modeled impacts. Rather than model each of the numerous combinations of operating load and ambient temperature that are provided by the vendor, a simplified and conservative analysis was performed by modeling the lowest stack flow rate and corresponding temperature at each of the 100%, 75%, 50%, and minimum operating loads; the lowest stack flow rates typically occur in the high ambient temperature operating scenarios.

CT4-CT5 hourly emissions of NO_X and CO are highest during startup operations. The short-term NO_X and CO modeling analyses were made conservative by modeling high startup hourly emissions for CT4-CT5 that included compliance margins (302 lb/hr for NO_X and 1,500 lb/hr for CO for each of CT4 and CT5) combined with minimum load stack flows rates and temperatures. For the PM_{10}, $PM_{2.5}$, and SO_2 load screening, the emission rates used for the reduced load scenarios were ratioed from the 100% load emissions based on the relative heat input rate (emissions of these pollutants are directly related to heat input rates). Attachment A presents the load screening data used in the modeling analyses.

5.3 Significant Impact Analysis

An air quality modeling analysis is typically conducted in two steps: an initial or "significant impact analysis", followed, if necessary, by a refined or "cumulative" NAAQS analysis. In the significant impacts analysis, the maximum model predicted impacts are compared to the pollutant specific SILs as listed in Table 1. Pollutants with impacts that exceed the SILs would then be evaluated for NAAQS compliance in a refined minor-NSR analysis.

Table 1. PSD Class II Significant Impact Levels (SILs)

Pollutant	Averaging Time	PSD Class II Significant Impact Levels (µg/m^3)
NO_2	1-hour	7.5
	Annual	1
CO	1-hour	2000
	8-hour	500
$PM_{2.5}$	24-hour	1.2
	Annual	0.13
PM_{10}	24-hour	5

5.4 Modeling for HAPs Sources – Learning Sites Policy

ADEQ has established the Learning Sites Policy to ensure that children at learning sites are protected from criteria air pollutants and air toxics or Hazardous Air Pollutants (HAPs). Learning sites consist of all existing public schools, charter schools, and private schools at the K-12 level, and all planned sites for schools approved by the Arizona School Facilities Board. Any facility located within 2 miles of a learning site is subject to the Policy and must submit a modeling analysis to demonstrate compliance with the NAAQS and acute/chronic ambient air concentrations for listed HAPs. The only school within 2 miles of SPP is the Red Rock Elementary School located 1.9 miles distant. Therefore, additional modeling was conducted pursuant to the Learning Sites Policy. Refer to Section 6 of this report for the results of the HAPs analysis.

5.5 Secondary $PM_{2.5}$ Impact Analysis

ADEQ's minor-NSR modeling guidance does not explicitly require the consideration of secondary $PM_{2.5}$ impacts when performing the minor-NSR air quality analysis. However, to be conservative, the SPP minor-NSR $PM_{2.5}$ modeling did include the effects of secondary $PM_{2.5}$ impacts.

EPA has issued "Guidance for Ozone and Fine Particulate Matter Permit Modeling" on July 29, 2022. The guidance addresses both primary and secondary $PM_{2.5}$ impacts. Primary $PM_{2.5}$ impacts refer to the impacts due to direct emissions of $PM_{2.5}$, and secondary impacts refer to the $PM_{2.5}$ impacts attributable to nitrates and sulfates formed due to precursor NO_2 and SO_2 emissions. The EPA guidance provides procedures including the Tier 1 MERPs procedure for calculating secondary $PM_{2.5}$ impacts.

The MERPs methodology uses empirical relationships between precursors and secondary $PM_{2.5}$ formation derived from photochemical grid modeling studies; it provides a simple way to calculate the secondary $PM_{2.5}$ impacts from the NO_X and SO_2 precursor emission rates. MERPs have been derived by EPA for various areas of the country. The MERPs used for this secondary $PM_{2.5}$ impacts analysis were taken from EPA's "MERPs VIEW Qlik" webpage that provides access to EPA's hypothetical single source modeled impacts of $PM_{2.5}$ to support PSD permit modeling analyses. MERPs are provided for La Paz County, Arizona, which is representative of the SPP location as it is in same lowland Sonoran desert ecosystem as SPP. The lowest MERPs (which results in the highest predicted impact) for either 10 or 90 meter stack heights and 500 tpy emissions or less were used in the analysis. The daily $PM_{2.5}$ MERP NO_X value is 21,527 and the SO_2 value is 2,333. The Project emission increases of the $PM_{2.5}$ precursors will be limited to less than 250 tpy of NO_X and 10 tpy of SO_2. Therefore, the calculated 24-hr secondary $PM_{2.5}$ impact is 0.016 µg/m3. The annual $PM_{2.5}$ MERP NO_X value is 265,647 and SO_2 value is 28,615. Given the Project emissions, the calculated annual secondary $PM_{2.5}$ impact is 0.001 µg/m3. These values were added to the Project's primary $PM_{2.5}$ modeling results, although both secondary formation

concentrations are so low that they are within the rounding error of the primary $PM_{2.5}$ modeled concentrations.

5.6 Single Source Ozone Impact Analysis

ADEQ's minor-NSR modeling guidance does not explicitly require the consideration of single source ozone impacts when performing the minor-NSR air quality analysis. However, to be conservative, the SPP minor-NSR modeling analysis did consider the ozone impacts of the Project.

EPA has issued "Guidance for Ozone and Fine Particulate Matter Permit Modeling" on July 29, 2022. The guidance addresses not only secondary $PM_{2.5}$ impacts but also ozone impacts. The EPA guidance describes procedures for calculating ozone impacts including the Tier 1 MERPs procedure.

The MERPs used for this ozone impact analysis were taken from EPA's "MERPs VIEW Qlik" webpage that provides access to EPA's hypothetical single source modeled impacts of $PM_{2.5}$ to support PSD permit modeling analyses. MERPs are provided for La Paz County, Arizona, which is representative of the SPP location as it is in same lowland Sonorian desert ecosystem as SPP. The lowest MERPs (which results in the highest predicted impact) for either 10 or 90 meter stack heights and 500 tpy emissions or less were used in the analysis. The 8-hour ozone MERP NO_X value is 214 and the VOC value is 24,649. The Project emission increases of the ozone precursors will be limited to less than 250 tpy of NO_X and 61 tpy of VOC. Therefore, the calculated 8-hr ozone impact is 1.17 ppb (0.00117 ppm). The background ozone concentration from the nearby Pinal Air Park monitor is 0.067 ppm, and when the project impact is added the total concentration is 0.068 ppm which is below the ozone standard of 0.07 ppm. Therefore, the Project will not cause or contribute to an exceedance of the ozone standard.

6.0 MODEL RESULTS AND CONCLUSIONS

This section presents the results of the AERMOD modeling analyses. AERMOD input and output files, including BPIP-PRIME files, are provided electronically for agency review.

6.1 Load Analysis Results

The results of the AERMOD CT4-CT5 load analysis can be found in Attachment A. The 100% load scenario resulted in the highest impacts for PM_{10}, $PM_{2.5}$, and SO_2, while the start-up/minimum load scenario resulted in the highest impacts for CO and NO_X. The emissions and stack parameters associated with these worst-case load conditions were used in the remainder of the analysis for the relevant pollutant.

6.2 Significant Impact Analysis Results

Table 2 presents the results of the significant impact analysis. The impacts for NO_2 and $PM_{2.5}$ are above the SILs, therefore a minor-NSR NAAQS analysis is required for these pollutants. The impacts for CO and PM_{10} were below the SILs. The fact the Project PM_{10} impacts are below the SIL demonstrates that the Project does not cause or contribute to exceedances of the PM_{10} standard both in the surrounding attainment area as well as the nearby West Pinal PM_{10} nonattainment area.

Table 2. Significant Impact Analysis Results

Pollutant	Avg Period	Maximum Modeled Impact - ($\mu g/m^3$)	PSD Significant Impact Level ($\mu g/m^3$)	Exceeds SIL?
NO_2	1-hr	45	7.5	Yes
	Annual	2.0	1	Yes
CO	1-hr	253	2000	No
	8-hr	79	500	No
$PM_{2.5}$	24-hr	2.4	1.2	Yes
	Annual	0.3	0.13	Yes
PM_{10}	24-hr	2.7	5	No

6.3 NAAQS Analysis Results

For pollutants/averaging intervals with project impacts above the SIL, ADEQ's minor-NSR modeling guidance requires that the applicant demonstrate that the ambient concentrations resulting from all emission sources at the facility, combined with background concentrations, will not cause an exceedance of the NAAQS.

In addition, this Project is subject to the Learning Sites policy, therefore a facility-wide modeling analysis for NAAQS and air toxics was required; the NAAQS results are presented in this section, and the air toxics results are presented in Section 6.4.

Table 3 presents the results of the NAAQS analyses. All of the facility impacts plus background concentrations are below the NAAQS. This minor-NSR modeling analysis thereby demonstrates that emissions from SPP will not cause or contribute to an exceedance of the NAAQS.

Table 3. NAAQS Analysis Results

Pollutant	Avg Period	Maximum Modeled Impact µg/m3	Background Concentration µg/m3	Total Concentration µg/m3	NAAQS µg/m3	Percentage of NAAQS
NO_2	1-hr	104	58	162	188	86%
	Annual	3.1	13.4	16.5	100	17%
$PM_{2.5}$	24-hr	1.8	21.8	23.6	35	67%
	Annual	0.3	5.4	5.7	9	63%
PM_{10}	24-hr	2.7	55.3	58	150	39%
CO	1-hr	315	1260	1575	40000	4%
	8-hr	224	687	911	10000	9%
SO_2	1-hr	0.5	9.2	9.7	196	5%
	3-hr	0.5	9.2	9.7	1300	1%
	24-hr	0.3	9.2	9.5	365	3%
	Annual	0.04	0.23	0.27	80	0%

6.5 Learning Sites Analysis Results

ADEQ has established the Learning Sites Policy to ensure that children at learning sites are protected from criteria air pollutant and air toxics or hazardous air pollutants (HAPs) impacts. Any facility subject to the Policy must submit a modeling analysis to demonstrate compliance with the NAAQS and acute/chronic ambient air concentrations for listed air toxics. The Learning Sites Policy NAAQS analysis has been presented in Section 6.4 of this report, and the HAPs analysis results are presented in this section.

The great majority of the SPP HAP emissions occur from the CTs. Rather than modeling each of the 20 HAPs individually from each CT, a simplified yet conservative analysis was performed by modeling each of the CTs separately using a unitized emission rate of 1 tpy and determining which CT results in the highest normalized impact. That analysis indicates that CT3 has the highest impact per unitized emission. The maximum 1-hr and annual average modeled impacts from CT3 were then scaled-up by the total facility HAP emission rate to calculate the facility's HAP impacts. These maximum impacts were not limited to model results at the location of the nearest school and are the maximum impacts at any location outside of the facility fence lines.

The results are presented in Table 4 and demonstrate that the SPP facility HAP impacts are below the Learning Sites acute and chronic Ambient Air Concentration (ACC) thresholds. This analysis shows compliance with the Learning Sites policy.

Table 4. Learning Sites Analysis Results

Hazardous Air Pollutant	CAS Number	TOTAL FACILITY Emissions tpy	Maximum 1-hr Impact mg/m3	Acute AAC mg/m3	Maximum Annual Average Impact mg/m3	Chronic AAC mg/m3	Does Facility Impact Exceed AACs
1,3-Butadiene	106-99-0	0.02	9.06E-07	7514	1.12E-08	6.32E-05	No
Acetaldehyde	75-07-0	1.66	8.43E-05	306	1.04E-06	8.62E-04	No
Acrolein	107-02-8	0.26	1.35E-05	0.23	1.67E-07	2.09E-05	No
Benzene	71-43-2	0.50	2.54E-05	1276	3.14E-07	2.43E-04	No
Dichlorobenzene	25321-22-6	0.00018	9.36E-09	300	1.16E-10	3.06E-04	No
Ethylbenzene	100-41-4	1.32	6.74E-05	250	8.35E-07	1.04E+00	No
Formaldehyde	50-00-0	10.80	5.50E-04	17	6.80E-06	1.46E-04	No
n-Hexane	110-54-3	11.01	5.60E-04	11649	6.93E-06	2.21E+00	No
Naphthalene	91-20-3	0.054	2.75E-06	75	3.40E-08	5.58E-05	No
PAH		0.092	4.66E-06	5	5.77E-08	2.02E-06	No
Toluene	108-88-3	5.38	2.74E-04	1923	3.39E-06	5.21E+00	No
Xylene	1330-20-7	2.65	1.35E-04	1736	1.67E-06	1.04E-01	No
Arsenic	7440-38-2	3.07E-05	1.56E-09	2.5	1.93E-11	4.41E-07	No
Cadmium	7440-43-9	1.72E-04	8.75E-09	0.25	1.08E-10	1.05E-06	No
Hydrogen Chloride	7647-01-0	2.23E-03	1.13E-07	16	1.40E-09	2.09E-02	No
Chromium	7440-47-3	2.15E-04	1.09E-08	0.10	1.35E-10	1.58E-07	No
Cobalt	7440-48-4	1.29E-05	6.55E-10	10.0	8.11E-12	6.86E-07	No
Manganese	7439-96-5	5.83E-05	2.97E-09	2.50	3.67E-11	5.21E-05	No
Mercury	7439-97-6	3.99E-05	2.03E-09	1.00	2.51E-11	3.13E-04	No
Nickel	7440-02-0	3.22E-04	1.64E-08	5.00	2.03E-10	7.90E-06	No

Attachment A

Emission and Stack Data
And Load Screening Results

Load Screening Inputs and Model Results

Stack and Emission Input Data

Scenario	Source Description	Stack Height (ft)	Temperature (F)	Exit Velocity (ft/s)	Stack Diameter (ft)	PM10/PM2.5 lb/hr	CO lb/hr	NO2 lb/hr	SO2 lb/hr
100	100	165	832	113.2	31	25	1500	302	2.0
75	75	165	832	85.4	31	20.8	1500	302	1.7
50	50	165	788.3	73.2	31	16.6	1500	302	1.3
Min/Startup	MinLoad	165	755.7	65.3	31	12.8	1500	302	1.0

Load Screening Results (worst-case impacts are highlighted in bold)

Scenario/Pollutant-Interval	NO2 1-hr	NO2 Annual	SO2 1-hr	SO2 3-hr	SO2 24-hr	SO2 Annual	PM10/PM25 24hr	PM10/PM25 Annual	CO 1-hr	CO 8-hr
100% Load	21.3	0.177	**0.126**	**0.052**	**0.011**	**0.00130**	**0.13**	**0.0163**	117.5	22.3
75% Load	20.3	0.187	0.102	0.046	0.010	0.00117	0.12	0.0143	112.2	23.4
50% Load	20.1	0.223	0.083	0.039	0.008	0.00107	0.11	0.0137	110.8	25.6
Min/Startup	**21.7**	**0.255**	0.072	0.034	0.007	0.00094	0.09	0.0120	**119.6**	**29.1**

Facility Emission and Stack Data
(CT4-CT5 stack parameters are for Min Load/Startup scenario)

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Elev (m)	Stack Ht (ft)	Temp (°F)	Exit Vel (fps)	Stack Dia (ft)	PM10/PM25 (lb/hr)	NO2 (lb/hr)	CO (lb/hr)	SO2 (lb/hr)	Ann PM10/PM25 (tpy)	AnnNO2 (tpy)	AnnSO2 (tpy)
CT1	CT1 501-AA	471943	3601886	585	37	846	108	17	6	300	77	1	27	1316	2.5
CT2	CT2 501-AA	471988	3601887	585	37	846	108	17	6	300	77	1	27	1316	2.5
CT3	CT3 GE-7EA	472111	3601885	587	60	1007	130	15	6	258	52	1	27	1129	2.5
CT4	New CT GE 7H	471476	3602430	581	165	756	65	31	25	302	1500	2	49	125	3.9
CT5	New CT GE 7H	471786	3602431	584	165	756	65	31	25	302	1500	2	49	125	3.9
CT4CT1	CT4-CoolTwrCell1	471514	3602346	582	10	105	32	6.5	0.05				0.24		
CT4CT2	CT4-CoolTwrCell2	471514	3602341	582	10	105	32	6.5	0.05				0.24		
CT5CT1	CT5-CoolTwrCell1	471823	3602347	584	10	105	32	6.5	0.05				0.24		
CT5CT2	CT5-CoolTwrCell2	471824	3602342	584	10	105	32	6.5	0.05				0.24		
DPHTR	NG Dew Point Heater	471254	3602466	580	25	150	14	2.6	0.18	1.30	1.40	0.02	0.77	5.67	0.092
FIREPUMP	Firepump	471475	3602365	582	12	880	77	0.5	0.17	0.08	2.92	0.01	0.02	0.34	0.001
ExistGen	Existing BESS Generator	472531	3601386	589	11	975	75	1.0	0.25	0.45	4.32	0.01	0.06	1.98	0.003
COOL1	Cooling Tower for CT1	471943	3601891	585	27	105	32	6.5	0.02				0.09		
COOL2	Cooling Tower for CT2	471988	3601891	585	27	105	32	6.5	0.02				0.09		
COOL3A	Cooling Tower for CT3 Cell A	472166	3601861	587	15	105	32	7.0	0.07				0.29		
COOL3B	Cooling Tower for CT3 Cell A	472166	3601864	587	15	105	32	7.0	0.07				0.29		

Note: The fire pump and existing BESS generator are intermittent sources, and in accordance with ADEQ policy the emissions modeled for the 1-hr NO_2 analysis are the annualized hourly emission rates.