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September 11, 2026

Ms. Anu Jain, Director
Pinal County Air Quality Control District
P.O. Box 987
Florence, Arizona 85132

Dear Ms. Jain,

Salt River Project Agricultural Improvement and Power District (SRP) is submitting the attached Class I permit application for the Marigold Energy Center (MEC). With this application, SRP is proposing to construct and operate three (3) natural gas-fired simple cycle combustion turbines at MEC.

If you have any questions regarding the enclosed permit application, please feel free to contact Zachary Harbin at (602) 236-5779.

Sincerely,

Jace Kerby

Jace Kerby
Director, Desert Basin, Coolidge, and Copper Crossing

Application for a Class I Air Permit for Marigold Energy Center Stanfield, Arizona

Submitted to:

Pinal County Air Quality Control District
31 N Pinal Street, Building F
PO Box 987
Florence, AZ 85132

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September 2026

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1. Introduction and Summary

1.1 Introduction

The Salt River Project Agricultural Improvement and Power District ("SRP") is seeking authorization in the form of a Class I permit to construct and operate a peaking plant with nominal capacity of ~675-megawatt ("MW") (at ISO[1] [2]) identified as the Marigold Thermal Plant Project or "the Project." The Project will be a part of the Marigold Energy Center ("MEC") in Pinal County, near Stanfield, Arizona. The Project will utilize frame-type simple cycle combustion turbine generators to generate electricity to serve peak demand. MEC will be located on an approximately 60-acre parcel located at the NE corner of N Stanfield Road and West Barnes Road within a portion of Section 5, Township 6 South, Range 4 East, in Pinal County, Arizona. The MEC will connect to the electrical grid through the new Marigold Substation, which is located just south of the proposed Marigold Thermal Plant Project.

The proposed Project constitutes a minor source under the Prevention of Significant Deterioration ("PSD") preconstruction permitting regulations and a new major source under the Title V operating permit regulations. This Class I permit application contains all required information, analyses and demonstrations under the Pinal County Title V regulations and all other applicable federal, State and County air quality regulations. The Pinal County Air Quality Control District ("PCAQCD") is the permitting authority for this Project. PCAQCD's permitting authority is explained in greater detail in section 4 of this application.

1.2 Project Schedule

SRP estimates that the plant will take approximately 13 to 19 months to construct the Project. SRP anticipates commercial operation by May 2032.

1.3 Permit Application Required Content and Forms

This document is SRP's application for a Class I permit for the proposed Project authorizing construction and operation of the Project. This section is the introduction and summary of the application. Section 2 presents a description of the process and proposed project. Project emissions and proposed limitations are presented in Section 3. Section 4 presents a regulatory applicability analysis. Section 5 includes the proposed permit conditions, limits and compliance methodologies.

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[1] International Organization for Standardization (ISO) establishes standardized conditions for combustion turbine operation as ambient temperature of 59 °F, altitude: sea level, ambient pressure: 14.7 psia, relative humidity: 60%.
[2] High ambient temperature during summer results in the inlet air temperature for the combustion turbines higher than the ISO conditions. Gas turbines take in a fixed volume of air, whose density decreases at higher temperature resulting in less oxygen available for combustion and lower power output when compared to the ISO conditions.

Completed permit application forms are contained in Appendix A for this permit application. Appendix B includes the site layout. Emissions calculations for the Project are included in Appendix C. The Acid Rain program application is included in Appendix D. Appendix E includes the air quality modeling report.

2. Project and Process Description

This section provides an overview of the Project and description of the proposed emission units.

2.1 Project Overview

SRP is proposing to construct the Project, natural gas-fueled electric generating station (using combustion turbines), site near the Town of Stanfield, Pinal County, Arizona. Project will provide the incremental peak capacity and will support the integration of renewable resources. The proposed facility design includes three (3) frame-type combustion turbines ("CT") that will drive electricity generators. SRP will utilize General Electric ("GE") 7F.05 combustion turbines, each with approximately 225 MW net generation capacity that will generally serve the peak electricity demand.[3]

2.2 Project Location

The SRP facility will be located in Stanfield, an unincorporated community in Pinal County, approximately 64 kilometers (40 miles) south of Tempe, Arizona. The approximate Universal Transverse Mercator (UTM) coordinates of the facility are 410,300 meters east and 3,643,500 meters north (UTM Zone 12, NAD 83). Figure 2-1 shows the general location of the facility. Figure 2-2 shows the specific facility location on a 7.5-minute U.S. Geological Survey (USGS) topographic map. Site layout for the facility is provided in Appendix B.

The facility is approximately 397 meters (1,300 feet) above mean sea level. The portion of Pinal County where the facility is located is designated as 'serious' nonattainment for particulate matter with an aerodynamic diameter of less than ten micrometers ("PM10"). This area is also designated 'moderate' nonattainment for PM2.5. The area is classified as attainment or unclassified for all other criteria pollutants.

[3] MW rating at International Organization for Standardization (ISO) conditions.

Figure 2-1. General Location of MEC (courtesy – Google Earth)

Figure 2-2. Specific Location of MEC (courtesy – Google Earth)

2.3 Simple Cycle Combustion Turbine Generators

The frame-type GE 7F.05 simple cycle CTs will drive electric generators to produce electric power for sale to the grid. A combustion turbine is an internal combustion system which uses inlet air as a working fluid to produce mechanical power. By design, simple cycle combustion turbine technology is capable of starting and ramping-up to full capacity within 30 minutes.

The combustion turbine comprises an air inlet system, a compressor section, a combustion section to combust natural gas fuel, and a turbine section. The air inlet system may include an inlet air heater, inlet air cooler, air filters, and noise silencer that supplies air to the multistage axial compressor. During operation, ambient air is drawn into the compressor section. Once the air is compressed it is heated by the combustion of gaseous fuel in the combustion section. The combusted gases then expand through the turbine section of the combustion turbine. The pressure differential across the turbine blades caused by this expansion rotates the shaft of the turbine thus rotating the coupled generator. The rotation of the generator is what produces the power that is supplied to the electrical grid.

Figure 2-3 presents a diagram for the proposed GE 7F.05 unit. The combustion turbines 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 through an inlet air evaporative cooling system. During cold weather, the filtered air may be heated by use of 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 air is drawn into the compressor section where the air is compressed. The compressed air is then channeled to the fuel/mix combustor section of the combustion turbine.

The combustor section is also known as the gas generator section. Fuel combustion process occurs in this section/stage. A transition duct within the combustion turbine then directs the flow of hot gases from the combustion section to the power section of the combustion turbine. In the power section, combustion gases produced in the gas generator section expand through the stage of the power turbine where the thermodynamic energy is converted to mechanical power. The mechanical power is then transferred through rotation of the shaft to drive both the compressor section and the electric generator to produce electricity. Combustion gases are then routed to any emission control systems and then pass to the combustion turbine exhaust stacks.

The general specifications for the proposed CTs provided by the manufacturer are summarized in Table 2-1. Note that the specifications in this table are for new turbines which have not undergone any performance degradation due to normal operation and do not account for efficiency reductions due to post combustion emission control systems.

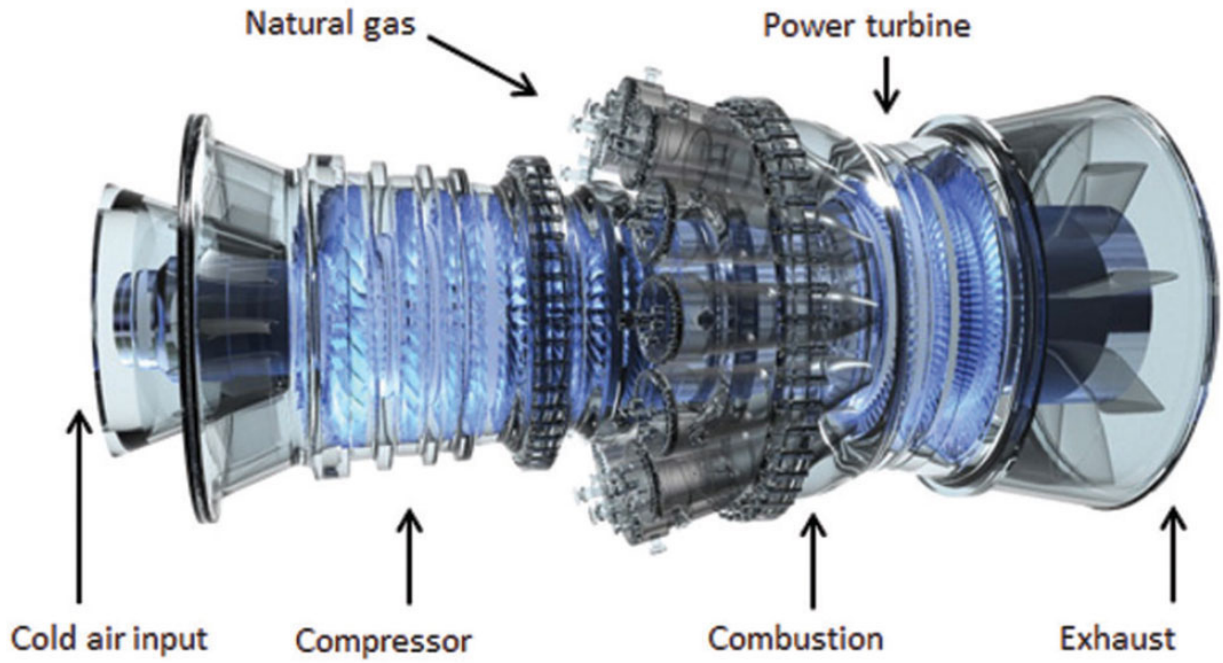


Figure 2-3. Diagram of a GE 7F Class Simple Cycle Combustion turbine (*from Science Break: Cogeneration, Oliver Kuhn, Recorder May 2013*)

Table 2-1. General Specifications for the GE 7F.05 Simple Cycle CTs

Parameter	Value
GE Model	7F.05 (60 Hz)
Number of units	3
ISO base output power (net)	225 MW (each)
Heat rate ISO full load (Net)	8,871 Btu/kW-hr (LHV)
Heat input rate ISO full load per CT	2,120 MMBtu/hour (LHV)

The combustion turbine will be enclosed in a metal acoustical enclosure which also contains auxiliary equipment. Each combustion turbine package will be equipped with the following equipment (to the extent needed):

- Inlet air filters
- Inlet evaporative cooling
- Anti-icing system
- Metal acoustical enclosure to reduce sound
- Duplex plate and frame lube oil coolers for the combustion turbine and generator
- DLN 2.6 Combustion Technology
- Fire detection and protection system
- Static Start with load commutated inverter (LCI)
- Compressor variable bleed valve vent to prevent compressor surge in off-design operation.

- Finned tube air-water heat exchanger
- Hydrogen cooled generator

2.4 Combustion Turbine Air Emissions Control Systems

The combustion gases exit the CTs at temperatures ranging from 760 °F to 1,100 °F. To enable the use of selective catalytic reduction ("SCR") systems for the proposed turbines, an air injection system is included. This system supplies tempering air to the exhaust of the turbine section to reduce the exhaust gas temperature to around 800 °F at the catalyst inlet. The exhaust gases will then pass through two post combustion air quality control systems: Oxidation Catalysts for the control of carbon monoxide ("CO") and volatile organic compounds ("VOC"), and SCR systems for the control of nitrogen oxide ("NO_X") emissions.

2.5 Emergency Fire Pump

An emergency fire pump powered by diesel-fired (compression ignition) reciprocating internal combustion engine ("RICE"), with maximum mechanical output rating of 190 hp will be installed as part of the Project. The emergency fire pump will be operated during emergency situations and for equipment maintenance and testing requirements. SRP is planning to install an EPA certified emergency fire pump.

2.6 Summary of Project Emissions Units

Table 2-2 presents a summary of the proposed emissions units for the Project.

Table 2-2. Proposed Emissions Units for the Project

Emission Unit	Designation	Description
1	SCCT1	GE 7F.05 simple cycle CT
2	SCCT2	GE 7F.05 simple cycle CT
3	SCCT3	GE 7F.05 simple cycle CT
4	FP	Emergency fire pump

3. Project Emissions

Project will be a new stationary source. Therefore, potential to emit ("PTE") of the regulated New Source Review (NSR) pollutants from the proposed equipment under the Project is used for air permitting purposes. The equipment proposed under the Project includes installation of three (3) natural gas fired simple cycle combustion turbines and other ancillary equipment. This section describes the emissions calculations for regulated NSR pollutants and hazardous air pollutants ("HAPs").

3.1 Regulated NSR Pollutants Emissions

This section summarizes PTE calculations and resulting emissions rates for regulated NSR pollutants from the emissions units proposed as part of the Project. The regulated NSR pollutants included here are NO_X, CO, VOC, sulfur dioxide ("SO_2"), particulate matter ("PM"), particulate matter equal to or less than an aerodynamic diameter of nominally 10 µm ("PM10") and 2.5 µm ("PM2.5"), sulfuric acid mist ("H_2SO_4 mist"), and lead ("Pb"). For purposes of this permit application, emissions of greenhouse gases ("GHGs") are calculated and presented as if this is a regulated NSR pollutant and are quantified on a carbon dioxide equivalent ("CO_2e") basis. CO_2e is calculated in accordance with 40 CFR §52.21(b)(49)(ii) using the mass emission rates of six GHGs[4] defined in 40 CFR §52.21(b)(49)(i) and corresponding global warming potential ("GWP") published in 40 CFR 98, Subpart A, Table A-1. For this application, Table A-1 GWPs from July 1, 2026, version of the 40 CFR Part 98 are used.

3.2 CT Generators GE 7F.05 Regulated NSR Pollutants

Emissions from the proposed CTs (SCCT1-SCCT3) during startup / shutdown and normal operation are presented below.

3.2.1 Normal Operation

The manufacturer's emissions data is provided in Appendix C for a wide range of unit operating load and ambient air conditions. The PTE of regulated NSR pollutants for the proposed CTs are based on the maximum rated heat input for the combustion turbines of 2,480 MMBtu per hour (higher heating value or "HHV"). This heat input rate for the CTs is for the site conditions at 20 °F ambient temperature at full load. Table 3-1 presents the design parameters and emissions information for the proposed GE 7F.05 CTs.

[4] The aggregate group of six greenhouse gases are: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. (40 CFR § 52.21(b)(49)(i)) Per 40 CFR § 52.21(b)(49)(iv) (implemented per delegation agreement with EPA), GHGs are considered subject to regulation only if the stationary source is a new major stationary source subject to PSD permitting for a regulated NSR pollutant that is not GHGs and also will emit or will have the potential to emit75,000 tons of CO_2e per year or more. As noted later in this application, the Project will not be a major stationary source for non-GHG pollutants. Therefore, GHGs are not considered subject to regulation for PSD.

Maximum emission rates for NO_X, CO, and VOC are from the equipment specifications included in Appendix C for the proposed CTs. These are based on 100% load condition, at site elevation, for different ambient temperature representing worst case. These emission rates are also based on the application of SCR and Oxidation Catalyst for the proposed CT units. Maximum annual average sulfur concentration is from the fuel specifications for pipeline natural gas supply in 40 CFR § 72.2. Particulate matter (PM/PM10/PM2.5) and H_2SO_4 mist emission rates are also based on the equipment specifications for the proposed units. Other emission factors are from U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42 and 40 CFR Part 98 and other similar projects.

Table 3-1. Design Parameters for the Proposed GE 7F.05

Parameter	Value	Units
Number of units	3	
Maximum heat input (20 °F, site elevation, full load)	2,480	MMBtu/hour (HHV)
Annual utilization rate per CT for normal operation	2,190	hours/year
Maximum NO_X emission rate	22.4	lb/hour
Maximum CO emission rate	19.1	lb/hour
Maximum VOC emission rate	6.3	lb/hour
Maximum PM10/PM2.5 emission rate	14.4	lb/hour

The PTE of regulated NSR pollutants from the simple cycle combustion turbines, SCCT1, SCCT2, and SCCT3, during normal operation using the conservative emission rates show above, are summarized in Table 3-2.

Table 3-2. PTE for SCCT1 – SCCT3 for Normal Operation

Pollutant	Emissions per CT (tons/year)
PM	7.9
PM10	15.8
PM2.5	15.8
SO_2	5.4
NO_X	24.5
VOC	6.9
CO	20.9
H_2SO_4 mist	2.8
CO_2e	372,607
Example calculations: $NOx = 22.4\left[\frac{lb}{hour}\right] * 2{,}190\left[\frac{hours}{year}\right] * \frac{1}{2{,}000}\left[\frac{ton}{lb}\right] = 24.5\left[\frac{tons}{year}\right]$	

3.2.1.1 Startup and Shutdown Emissions

The air pollution control systems including SCR and CO Oxidation Catalysts are not operational during the startup and shutdown of the CTs. The emissions control systems are not fully functional during periods of startup and shutdown because the exhaust gas temperature is low and outside the optimum range for these systems to function as designed. During a startup, as the CT achieves minimum emissions compliance load ("MECL"), the CT emissions controls reduce

the stack emission rates of NO_X and CO below the rates in the emissions specifications for normal operation.

For simple-cycle combustion turbines, the time required for startup is much shorter than combustion turbines used in combined cycle applications.[5] The CTs are able to achieve full capacity within 10 minutes but the SCR requires a warm-up of up to 20 minutes to achieve optimum temperature for emissions control. Therefore, the unit achieves MECL in ~22 minutes and for purposes of this permit application, emissions calculations have been conducted using the full 22 minutes for a startup event. The length of time for a normal shutdown, that is, the time from the MECL to the time when the flame out occurs, is normally 15 minutes. Therefore, the normal duration for a startup and shutdown event is 37 minutes. In Table 3-3, the startup and shutdown emissions are detailed by event, and the maximum annual emissions are also shown. The startup and shutdown annual emissions are calculated using an assumption of 150 startups and shutdowns events per year per CT. NOx, CO, VOC, and particulate matter emission rates during startup and shutdown, in terms of pounds per event, were provided by GE. Emissions of other pollutants are calculated using the emission factors for normal operation and heat input for a startup and shutdown events. Heat input for a startup and shutdown event for the CT is from the equipment vendor information for the proposed CTs.

The expected emissions during a startup and shutdown are summarized in Table 3-3.

Table 3-3. PTE for SCCT1 – SCCT3 for Startup/Shutdown Cycles

Pollutant		
PM	7.2	0.5
PM10	14.4	1.1
PM2.5	14.4	1.1
SO_2	-	0.1
NO_X	115.4	8.7
VOC	71.6	5.4
CO	687.4	51.6
H_2SO_4	-	0.2
CO_2e	-	25,521
Example calculations: $NOx = \left[115.4\left[\frac{lb}{su/sd}\right]\right] * 150\left[\frac{cycles}{year}\right] * \frac{1}{2{,}000}\left[\frac{ton}{lb}\right] = 8.7\left[\frac{tons}{year}\right]$		

PTE of the three CTs combined with PTE of the other unit in the proposed Project is presented in sub-section 3.2.3.

[5] Heating up the heat recovery steam generator and associated steam turbine system in a combined cycle setup requires a slow ramp up of the CT resulting in longer startup and shutdown durations.

3.2.2 Diesel Emergency Fire Pump

The emergency fire pump (FP) will include a compression ignition, reciprocating internal combustion engine to drive the water pump to serve the plant fire emergency needs. The specifications for the proposed fire pump RICE are summarized in Table 3-4.

Table 3-4. Specifications for Fire Pump RICE

Parameter	Value
Fuel	Diesel
Power Output (kW)	142
Power Output (hp)	190
Heat Input (MMBtu/hour)	1.42
Maximum annual hours of operation (hours/year)[6]	500

The proposed diesel RICE will be a certified unit as required in 40 CFR §60.4205(c) and subject to the emissions standards in Table 4 of 40 CFR 60 Subpart IIII for NOx, CO, VOC, and PM. For emissions calculations, vendor data, fuel sulfur, and other emission factors from AP-42 and 40 CFR Part 98 are used.

3.2.3 Summary of Project Potential to Emit of Regulated NSR Pollutants

Table 3-5, summarize PTE of regulated NSR pollutants and GHGs (in terms of CO_2e) for the Project. Detailed emissions calculations are provided in Appendix C.

Table 3-5. Summary of PTE for Project

Pollutants	Potential to Emit (tons/year)		
	SCCT1-SCCT3	FP	Total
PM	25.3	0.0	25.3
PM10	50.5	0.0	50.6
PM2.5	50.5	0.0	50.6
SO_2	16.6	0.0	16.6
NOx	99.5	0.3	99.9
VOC	36.8	0.1	36.9
CO	217.4	0.3	217.7
H_2SO_4	9.1	0.0	9.1
GHG/CO_2e	1,194,386	58	1,194,444

Applicability of permitting requirements for the project are discussed in the next section of this application.

[6] See letter regarding *Accounting for Emergency Generators in the Estimate of Potential to Emit,* Steven C. Riva, Chief Permitting Section U.S. EPA Region 2, February 14, 2006.

3.3 Hazardous Air Pollutants Emissions

HAP emissions from the proposed emissions units under the Project are presented in this section.

3.3.1 Combustion Turbine HAPs Emissions Estimates

Combustion of natural gas in combustion turbines forms HAPs. However, natural gas fired CTs generate relatively small HAP emissions. HAP emissions are calculated for the CTs using the maximum annual heat input. All the CTs will include oxidation catalyst control for CO and VOCs. These controls will also reduce organic HAPs from the CTs. For normal operation heat input, 50% control efficiency is applied for organic HAPs emissions. To be conservative, it is assumed that there will be no control of HAPs during the CT startup or shutdown (also assuming worst case heat input rate for this period).

The HAP emission factors are from the U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42, Volume 1: Stationary Point and Area Sources, Section 3.1, Stationary Combustion turbines and BAAQMD TAC Emission Factor Guidelines. Potential emissions for the proposed new CTs are detailed in Table 3-6.

Table 3-6. HAPs from CTs

HAPs	SCCT1-SCCT3 Emissions (tons/year)
Acetaldehyde	0.2
Acrolein	0.0
Benzene	0.1
Ethylbenzene	0.1
Formaldehyde	3.1
Hexane	1.1
Naphthalene	0.0
PAHs	0.0
Toluene	0.6
Xylenes (mixed)	0.3
Total	5.5

3.3.2 Fire Pump HAPs Emissions

Diesel fuel combustion in the RICE unit of the fire pump will result in HAP emissions. The potential emissions of HAPs are summarized in Table 3-7. HAP emissions are based on emission factors from the U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Tables 3.4-3 and 3.4-4 and California Air Toxics Emission Factor (CATEF).

3.3.3 Summary of Source-wide HAPs Emissions

Table 3-7 presents the HAPs emissions from the Project.

Table 3-7. Source-wide HAPs Emissions

HAPs	Emissions (tons/year)		
	SCCT1-SCCT3	FP	Total
Acetaldehyde	1.8E-01	9.0E-06	0.2
Acrolein	2.8E-02	2.8E-06	0.0
Benzene	5.3E-02	2.8E-04	0.1
Ethylbenzene	1.4E-01	-	0.1
Formaldehyde	3.1	2.8E-05	3.1
Hexane	1.1	3.7E-06	1.1
Naphthalene	5.7E-03	4.6E-05	0.0
PAHs	9.7E-03	7.5E-05	0.0
Toluene	5.7E-01	1.0E-04	0.6
Xylenes (mixed)	2.8E-01	6.9E-05	0.3
Total	5.5	6.1E-04	5.5

Maximum PTE of a single HAP (formaldehyde) is 3.1 tons per year, and total PTE of all HAPs is 5.5 tons per year.

4. Regulatory Applicability Review

A review of the potentially applicable federal and Pinal County regulations has been conducted for the proposed Project. The following subsections summarize the applicability of these regulations to the proposed Project.

4.1 County Regulations

This analysis is based on the latest version of the Pinal County Air Quality Control District Code of Regulations ("Code") (as amended February 19, 2026) available from the District's website.[7]

4.1.1 Applicability and Classes of Permits (Code Chapter 3, Article 1)

The PCAQCD Code Chapter 3, Article 1, Section 040 [Code §3-1-040] requires a Class I permit prior to commencing construction on an "affected source" as well as a "major source." An affected source is defined in Code §3-1-080 as "[a] source that includes one of more units which are subject to emission reduction requirements or limitations under Title IV of the Clean Air Act (1990)." As explained later in this section, the proposed CTs under the Project will be subject to the requirements of the Acid Rain Program under 40 CFR Part 72 and Title IV of the Clean Air Act. Also, as shown in Table 3-5, PTE of regulated air pollutants for the project exceeds the 100 tons per year major source threshold in Code §1-3-140(80)(c). Therefore, a Class I permit is required for the proposed Project.

A completed "Permit Application Form" (from Appendix A of the Code) for a Class I permit is provided in Appendix A of this application. A review of applicable requirements per Code §3-1-055(B), for completeness determination, is provided in this section.

Even though not specifically required under the applicable regulations, SRP plans to conduct an ambient air quality assessment for the proposed Project. An air quality dispersion modeling assessment protocol was submitted via email to PCAQD on July 23, 2026. An ambient air quality dispersion modeling assessment reported is included in Appendix E This assessment confirms that the ambient concentrations resulting from the Project will not interfere with attainment or maintenance of a national ambient air quality standard ("NAAQS").

4.1.2 Permit Requirements for New Major Sources (Code Chapter 3, Article3)

The Project will involve installation of three natural gas fired CTs, in simple cycle operation. The Project site is located north of Stanfield Arizona, in the 'serious' PM10 nonattainment area of Pinal County. This location is also within the West Central Pinal PM2.5 nonattainment area (classified as 'moderate'). The site area is attainment or unclassifiable for all other criteria pollutants. PM10 and PM2.5 emissions are evaluated for nonattainment major new source review ("NNSR") applicability under Code §3-3-203(2)(a). All other regulated NSR pollutants are evaluated for prevention of significant deterioration ("PSD") applicability under Code §3-3-203(2)(b). On August 10, 2011, the U.S. EPA Region 9 delegated the permitting authority for

[7] https://www.pinal.gov/415/Pinal-County-Code-of-Regulations (last accessed on June 23, 2026).

GHGs under the federal PSD program, at 40 CFR §52.21, to PCAQCD.[8] For purposes of determining applicability of 'major source' under Code §3-3-203(2) and 40 CFR §52.21(b)(1), PTE of regulated NSR pollutants for the proposed equipment under the Project is presented in Table 4-1 and compared with the applicable thresholds. Equipment under the proposed Project does not belong to the "categorical sources" list in Code §1-3-140(25).

Table 4-1. NNSR & PSD Applicability for Project

Pollutant	Source PTE (tons/year)	Major Source Threshold (tons/year)	Whether Major?
PM	25.3	250	No
PM10	50.6	70	No
PM2.5	50.6	100	No
SO_2	16.6	100	No
NOx	99.9	100	No
VOC	36.9	250	No
CO	217.7	250	No
H_2SO_4	9.1	250	No
CO_2e	1,194,444	-NA-	-NA-
*Determination whether GHGs are "subject to regulation."			

For the proposed MEC facility, PTE of PM10 is less than 70 tons per year and that of PM2.5 and its precursors are less than 100 tons per year each. Therefore, the NNSR requirements of Code §§3-3-220 and 230 are not applicable to the proposed facility. PTE of all other regulated NSR pollutants from the Project is below 250 tons per year. Therefore, the proposed Project is a minor source for PSD. The PSD requirements in Code §3-3-250 do not apply to the Project. In accordance with 40 CFR §52.21(b)(49)(iv)(a), GHGs are not "subject to regulation" because the Project is not a new major stationary source for non-GHGs.

4.1.3 Permit Fees (Code Chapter 3, Article 7)

The proposed Project will be a 'new source.' Code §3-7-580 requires a deposit fee of $4,000 for a new source required to obtain a Class I permit pursuant to Code §3-1-040.B.1. This fee is assessed upon receipt of the application. This fee will be credited toward permit processing fee that will reflect the amount due to the actual time spent on processing the application. A check in the amount $4,000 drawn in favor of PCAQCD is attached to this submittal. SRP will promptly pay all necessary fees upon receiving any invoices from PCAQCD.

4.1.4 West Pinal PM10 Fugitive Dust Requirements (Code Chapter 4, Article 1)

The proposed Project will be located in the West Pinal County Serious PM10 nonattainment area. Therefore, open areas/vacant lots, any unpaved roads, and unpaved lots will be subject to the measures to prevent, reduce or mitigate fugitive dust emissions.

[8] Available at: https://www.epa.gov/sites/production/files/2015-08/documents/pinal_county_ghg_psd_delegation_agreement.pdf. (last accessed on June 23, 2026)

4.1.5 Fugitive Dust (Code Chapter 4, Article 2)

The proposed Project will be subject to the requirements of this rule and will comply with requirement to reasonably regulate operations that periodically may cause fugitive dust emissions into atmosphere.

4.1.6 Stationary Source Performance Standards (Code Chapter 5)

Chapter 5 of the Code specifies performance standards for new and existing source categories. This section presents the applicability of these requirements to the proposed units.

4.1.6.1 Fossil Fuel Fired Industrial and Commercial Equipment (Code Chapter 5, Article 21)

The proposed equipment (combustion turbines and the emergency fire-pump) are direct fired and do not involve any units where products of combustion come into direct contact with the process materials. Therefore, pursuant to Code §5-21-920, these units are not subject to the requirements of this standard.

4.1.6.2 Fossil Fuel Fired Steam Generators (Code Chapter 5, Article 22)

The proposed Project does not include any units that produce steam. Therefore, requirements of this standard are not applicable to the proposed Project.

4.1.6.3 Stationary Rotating Machinery (Code Chapter 5, Article 23)

In accordance with Code §5-23-990, requirements of this standard apply to stationary combustion turbines and internal combustion engine.

(a) Pursuant to Code §5-23-1010(A), particulate matter emissions from the proposed combustion turbines and fire pump shall not exceed the allowable particulate matter emissions rate per the following equation for units with heat input rate of 4,200 MMBtu per hour or less.

$$E = 1.02Q^{0.432}$$

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/hour.

(b) Pursuant to Code §5-23-1010(C), opacity of exhaust from the proposed CTs and fire pump shall not exceed 40% for any period greater than 10 consecutive seconds. Visible emissions when starting cold equipment shall be exempt for the first 10 minutes.

The proposed CTs will fire natural gas only. The emergency fire pump will use ultra-low sulfur diesel fuel. Emissions from these operations are expected to be in compliance with the requirements of Code §§5-23-1010(A) and (C).

(c) For the emergency fire pump, SRP will only use ultra-low sulfur diesel, which will be in compliance with the SO_2 limit of 1.0 lb/MMBtu per Code §5-23-1010(D).

4.1.6.4 Miscellaneous and Unclassified Source Requirements (Code Chapter 5, Article 24)

Use of ultra-low sulfur diesel will ensure that the emissions from the fire-pump shall be in compliance with the SO_2 emission limitation in Code §5-24-1030(A)(2) of 600 ppm.

NOx emissions from the proposed equipment will be in compliance with the 500 ppm limit in Code §5-24-1030(A)(3).

4.1.7 Control of Federally Listed HAPs (Code Chapter 7, Article 1)

Code §7-1-040 (A) generally requires that construction of a new major source of federally listed HAPS shall install maximum achievable control technology (MACT) for the new major source determined on a case-by-case basis in Code §7-1-040 (B) and Code §7-1-050 (A). As noted in section 3.3.3, for the Project, the potential emissions of a single HAP are less than 10 tons per year, and the potential emissions of total HAPs are less than 25 tons per year. Therefore, the Project does not meet the definition of 'major source' in Code §7-1-020 (5) as the HAPs PTE is below the applicable regulatory thresholds and the case-by-case MACT requirements in Code §7-1-050 (A) do not apply to the Project.

4.2 Federal Regulations

4.2.1 New Source Performance Standards (40 CFR Part 60; Code Chapter 6)

Some of the federal new source performance standards ("NSPS") requirements are incorporated by reference in Code §6-1-030. Applicability of the NSPS requirements for the proposed units is presented below.

4.2.1.1 General Provisions, 40 CFR Part 60, Subpart A

SRP will comply with the applicable requirements under general provisions of 40 CFR Part 60 Subpart A. These will include notifications, compliance testing, monitoring, recordkeeping and reporting provisions of the rule.

4.2.1.2 Standards of Performance for Stationary Combustion Turbines, 40 CFR Part 60, Subpart KKKKa

NSPS 40 CFR Part 60, Subpart KKKKa applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu per hour that commence construction after December 13, 2024. Further the proposed CTs will be 'large' CT (unit with base load rating greater than 850 MMBtu/hour) and will not operate with capacity factors greater than 45 percent and will have design efficiency less than 38%. The proposed simple cycle combustion turbines will be affected facilities under this NSPS and will be subject to the following standards:

(a) When operating at greater than or equal to 70% of base load rating for the hour, comply with the NOx emission limit of 9 ppm at 15 percent O_2 or 0.033 lb/MMBtu (for

combustion turbine firing natural gas with heat input greater than 850 MMBtu per hour and capacity factor <45% and design efficiency <38%) on a four (4) hour rolling average basis. (40 CFR §60.4320a and Table 1 of NSPS Subpart KKKKa)

(b) When operating at less than 70% of base load rating for any duration during a give hour, comply with the alternate NOx emission limit of 96 ppm at 15 percent O_2 or 0.35 lb/MMBtu (for combustion turbine firing natural gas with output greater than 300 MMBtu/hour heat input) on a four (4) hour rolling average. (40 CFR §60.4320a and Table 1 of NSPS Subpart KKKKa)

(c) Comply with the SO_2 emission limits of 0.060 lb SO_2/MMBtu heat input. (40 CFR §60.4330a(a)(2))

(d) Compliance requirement –
   1. Conduct an initial NO_X performance test in accordance with 40 CFR § 60.8 using the applicable methods in 40 CFR § 60.4400a or § 60.4405a. (40 CFR 60.4333a(b)])
   2. Demonstrate continuous compliance using a continuous emission monitoring system (CEMS) for measuring NO_X emissions from the affected CTs per the requirements in 40 CFR § 60.4345a. (40 CFR 60.4333a(c))
   3. Conduct an initial SO_2 performance test in accordance with 40 CFR § 60.8 using the applicable methods in 40 CFR § 60.4400a or § 60.4405a.
   4. Conduct subsequent fuel sulfur analysis using the applicable methods specified in 40 CFR § 60.4360a and at the frequency specified in 40 CFR § 60.4370a. (40 CFR 60.4333a(d)(2))

(e) Demonstrate that the fuel burned is in compliance with SO_2 emission limitation noted above. The fuel analyses may be performed either by SRP, a service contractor retained by SRP, or the fuel vendor. (40 CFR 60.4360a(a))

(f) Comply with the reporting requirements in 40 CFR § 60.4375a(a) regarding excess emissions and monitor downtime.

4.2.1.3 Standards of Performance for Greenhouse Gas Emissions for Greenhouse Gas Emissions for … Stationary Combustion Turbine Electric Generating Units, 40 CFR Part 60, Subpart TTTTa

This NSPS applies to carbon dioxide (CO_2) emissions from certain stationary combustion turbines. As specified in 40 CFR § 60.5509a(a) of this subpart, the greenhouse gas ("GHG") standards included in this subpart apply to any combustion turbine that commenced construction after May 23, 2023, that meets the applicability conditions below:

(a) Has a base load rating greater than 250 MMBtu per hour of fossil fuel (either alone or in combination with any other fuel); and

(b) Serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

The three proposed simple cycle combustion turbines, each have a base load rating greater than 250 MMBtu per hour of fossil fuel and serve generators capable of selling greater than 25 MW of electricity. Therefore, these units are subject to the requirements of this standard.

The proposed units are not "base load" type as these will supply less than or equal to 40% of the potential electric output as net-electric sales on both 12-operating month and 3-year rolling

average basis. These units will either qualify as 'Intermediate Load Combustion Turbine' or 'Low Load Combustion Turbine' as defined in 40 CFR § 60.5580a. Therefore, per 40 CFR § 60.5520a(a), the proposed CTs will be subject to the CO_2 emission standards specified in Table 1 of the 40 CFR 60 Subpart TTTTa for those categories.

4.2.1.4 Standards of Performance for Stationary Compression Ignition Internal Combustion Engine, 40 CFR Part 60, Subpart IIII

NSPS 40 CFR Part 60, Subpart IIII applies to stationary compression ignition RICE, including fire-pumps that commence construction after 2009. The proposed fire-pump engine will be subject to the requirements of this rule as noted below:

(a) Comply with the emission limitations in Table 4-2 below. (40 CFR §§60.4202(d) and 60.4205(c), Table 4)

Table 4-2. NSPS IIII Requirements for the 190 HP Fire Pump Engine

Pollutant	Emission Standard (g/HP-hr)
NMHC+NOx	3.0
CO	2.6
PM	0.15

SRP plans to purchase a manufacturer certified (Tier 3) fire-pump RICE that will be in compliance with the above limitations.

(b) Use ultra-low sulfur diesel fuel per the requirements of 40 CFR §1090.305. (40 CFR §60.4207(b))

4.2.2 National Emissions Standards for Hazardous Air Pollutants (40 CFR Part 63; Code Chapter 7)

Some of the National Emissions Standards for Hazardous Air Pollutants ("NESHAP") requirements are incorporated by reference in Code §7-1-030. Applicability of the NESHAP requirements for the proposed units is presented below. Source-wide PTE of HAPs provided in Table 3-7 lists PTE of single HAPs and combination of HAPs as less than 10 tons per year and 25 tons per year, respectively. Therefore, the proposed Project will be an area source in 40 CFR §63.2 for applicability of NESHAP requirements.

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

NESHAP 40 CFR 63 Subpart YYYY applies to stationary combustion turbines at major sources of HAP emissions. The Project is an area source, and the new combustion turbines will not be subject to the requirements under this NESHAP.

4.2.2.2 National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR Part 63, Subpart ZZZZ

NESHAP 40 CFR 63 Subpart ZZZZ applies to RICE located at area and major sources of HAP emissions. The Project, an area source, will involve construction of an emergency fire-pump RICE. Pursuant to 40 CFR § 63.6590(c)(1) new stationary RICE located at an area source that are subject to 40 CFR Part 60 IIII are exempt from 40 CFR Part 63 Subpart A and Subpart ZZZZ.

4.2.3 Acid Rain Program (40 CFR Part 72 and Code Chapter 3, Article 6)

The federal acid rain program requirements at 40 CFR Part 72 are incorporated by reference in Code §3-6-565(A). Per 40 CFR §72.6(a)(3)(i), a 'utility unit,' that is a 'new unit' is considered an affected unit. Any source that includes such an affected unit shall be an affected source, subject to the requirements of the Acid Rain Program in 40 CFR Part 72. A "utility unit" means a unit owned or operated by a utility that serves a generator in any State that produces electricity for sale. Finally, "Unit" means a fossil fuel-fired combustion device. Because the new combustion turbine generators fire natural gas and produce electricity for sale, these new CTs are affected units under the federal Acid Rain Program. A copy of the Acid Rain Permit application has been submitted to EPA, and is included with this application as Appendix D.

5. Proposed Permit Terms and Conditions

This section of the application presents proposed permit terms and conditions for the Class I Permit for the Project.

As provided under Code § 3-1-084, SRP is proposing the following voluntary emission limitations for the proposed simple cycle combustion turbines (SCCT1, SCCT2, and SCCT3) to keep the project PTE below the NNSR and PSD thresholds (when accounting for the PTE of fire pump (FP)).

(1) Emission Limitations

a. The Permittee shall not cause or allow the combined NO_X emissions from SCCT1, SCCT2, and SCCT3 more than 99.5 tons per 12-month rolling total sum (combined for normal operation and startup/shutdown duration).

b. The Permittee shall not cause or allow the combined CO emissions from SCCT1, SCCT2, and SCCT3 more than 244 tons per 12-month rolling total sum (combined for normal operation and startup/shutdown duration).

c. The Permittee shall not cause or allow the combined PM10/PM2.5 emissions from SCCT1, SCCT2, and SCCT3 more than 69 tons per 12-month rolling total sum (combined for normal operation and startup/shutdown duration).

d. The Permittee shall not cause or allow the combined VOC emissions from SCCT1, SCCT2, and SCCT3 more than 244 tons per 12-month rolling total sum (combined for normal operation and startup/shutdown duration).

(2) Compliance Demonstration

a. Within 60-days after achieving maximum production rate of each CT (SCCT1, SCCT2, and SCCT3), but no later than 180 days after the initial start-up of the CT, Permittee shall conduct performance tests, using standard test methods approved by the EPA (40 CFR Part 60) specified below, or equivalent methods as approved by the District pursuant to approval of the test plan required below. These tests shall be performed at the maximum practical production rate. 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 emissions: Ref. Part 60, App. A-4, Ref. Method 7E

ii. Carbon monoxide emissions: Ref. Part 60, App. A-4, Ref. Method 10

iii. Particulate matter emissions (PM10, PM2.5): Ref. Part 60, App. A-3, Ref. Method 5 and Ref. Part 51 App. M, Ref. Method 202

iv. Volatile organic compounds emissions: Ref. Part 60, App. A-7, Ref. Method 25a

(3) Instrumental Emissions Monitoring Requirements– Nitrogen Oxides & Carbon Monoxide

a. The Permittee shall install, calibrate, maintain, and operate continuous emissions monitoring systems on SCCT1, SCCT2, and SCCT3, and record the output of each system, for measuring nitrogen oxide and carbon monoxide emissions to the atmosphere during startup and shutdown events and the normal operation of the combustion turbines. Monitoring equipment required under this subsection shall be installed and operated in accordance with a plan submitted to the District by the permittee.

b. On a calendar-month basis, Permittee shall generate a record of cumulative actual nitrogen oxide and carbon monoxide emissions from SCCT1, SCCT2, and SCCT3 emitted for the previous month and for the preceding 11- months and shall compare that total to the annual nitrogen oxide and carbon monoxide emissions limitations imposed under Condition ____. The Permittee shall maintain a record of those monthly total calculations, and monthly conclusion regarding compliance with the emission limitations under _____

(4) Parametric Emissions Monitoring – Particulate Matter

a. By the 10th day of each month, Permittee shall calculate and record the quantity of PM10/PM2.5 emissions from SCCT1, SCCT2, and SCCT3, separately for each unit, for the previous calendar month. Calculations shall be performed using records of fuel use data, startup and shutdown events, and emission factors, as provided in paragraph c below.

b. By the 10th day of each month, Permittee shall calculate and record the combined PM10/PM2.5 emissions from SCCT1, SCCT2, and SCCT3 on a rolling 12-month total sum basis. This value shall be calculated as the sum of the emission factors from both units during the previous month and during the preceding eleven months. Permittee shall compare this 12-month total to the annual PM10/PM2.5 emission limitations under _____ of this permit. Records of the monthly

total calculations and compliance with the PM10/PM2.5 emission limitations shall be maintained.

c. Monthly total PM10/PM2.5 emissions from each SCCT1, SCCT2, and SCCT3 shall be calculated, separately for each unit, as the sum of the emissions from that unit during startup and shutdown events, calculated as provided in paragraph d below, and the emissions from that unit during non-startup/shutdown periods, calculated as provided in paragraph e below.

d. PM10/PM2.5 emissions from startup and shutdown events at SCCT1, SCCT2, and SCCT3 shall be calculated as the product of the number of events and an approved emission factor of 14.4 pounds per event. An event is one startup followed by one shutdown.

e. PM10/PM2.5 emissions during non-startup/shutdown operating periods at SCCT1, SCCT2, and SCCT3 shall be calculated as the product of the cumulative heat input during such period, expressed in MMBtu, and the approved emission factor, expressed in lb/MMBtu.

    i. Permittee shall use an approved PM10/PM2.5 emission factor of 0.010 lb/MMBtu to calculate emissions from SCCT1, SCCT2, and SCCT3 during operating periods from the date of initial startup of SCCT1, SCCT2, and SCCT3 through the last day of the calendar month during which PCAQCD first approves a performance test-derived PM10/PM2.5 emission factor for SCCT1, SCCT2, and SCCT3 in accordance with paragraph f.

    ii. Following approval of a performance test-derived PM10/PM2.5 emission factor for SCCT1, SCCT2, and SCCT3 by PCAQD in accordance with paragraph f below, Permittee shall use the approved performance test-derived PM10/PM2.5 emission factor to calculate emissions during operating periods beginning with the first day of the calendar month after such approval. Permittee shall continue to use such approved performance test-derived PM10/PM2.5 emission factor until it is superseded by approval of a new test-derived PM10/PM2.5 emission factor for such SCCT1, SCCT2, and SCCT3.

f. During each PM10/PM2.5 performance test conducted at SCCT1, SCCT2, and SCCT3 pursuant to Section of this permit, Permittee shall calculate a performance test-derived PM10/PM2.5 emission factor for such combustion turbine and shall submit such emission factor to PCAQCD for approval. The test-derived emission factor shall be calculated as the arithmetic mean of the emission factor results for all valid runs conducted as part of such performance test. The emission factor result for each run shall be calculated by dividing the measured emission rate during that run, expressed in lb/hr, by the heat input rate during that run, expressed in MMBtu/hr.

(5) Parametric Emissions Monitoring – Volatile Organic Compounds

a. By the 10th day of each month, Permittee shall calculate and record the quantity of VOC emissions from SCCT1, SCCT2, and SCCT3, separately for each unit, for the previous calendar month. Calculations shall be performed using records of fuel use data, startup and shutdown events, and emission factors, as provided in paragraph c below.

b. By the 10th day of each month, Permittee shall calculate and record the combined VOC emissions from SCCT1, SCCT2, and SCCT3 on a rolling 12-month total sum basis. This value shall be calculated as the sum of the emission factors from both units during the previous month and during the preceding eleven months. Permittee shall compare this 12-month total to the annual VOC emission limitations under _____ of this permit. Records of the monthly total calculations and compliance with the VOC emission limitations shall be maintained.

c. Monthly total VOC emissions from each SCCT1, SCCT2, and SCCT3 shall be calculated, separately for each unit, as the sum of the emissions from that unit during startup and shutdown events, calculated as provided in paragraph d below, and the emissions from that unit during non-startup/shutdown periods, calculated as provided in paragraph e below.

d. VOC emissions from startup and shutdown events at SCCT1, SCCT2, and SCCT3 shall be calculated as the product of the number of events and an

approved emission factor of 71.6 pounds per event. An event is one startup followed by one shutdown.

e. VOC emissions during non-startup/shutdown operating periods at SCCT1, SCCT2, and SCCT3 shall be calculated as the product of the cumulative heat input during such period, expressed in MMBtu, and the approved emission factor, expressed in lb/MMBtu.

   i. Permittee shall use an approved VOC emission factor of 0.003 lb/MMBtu to calculate emissions from SCCT1, SCCT2, and SCCT3 during operating periods from the date of initial startup of SCCT1, SCCT2, and SCCT3 through the last day of the calendar month during which PCAQCD first approves a performance test-derived VOC emission factor for SCCT1, SCCT2, and SCCT3 in accordance with paragraph f.

   ii. Following approval of a performance test-derived VOC emission factor for SCCT1, SCCT2, and SCCT3 by PCAQD in accordance with paragraph f below, Permittee shall use the approved performance test-derived VOC emission factor to calculate emissions during operating periods beginning with the first day of the calendar month after such approval. Permittee shall continue to use such approved performance test-derived VOC emission factor until it is superseded by approval of a new test-derived VOC emission factor for such SCCT1, SCCT2, and SCCT3.

f. During each VOC performance test conducted at SCCT1, SCCT2, and SCCT3 pursuant to Section of this permit, Permittee shall calculate a performance test-derived VOC emission factor for such combustion turbine and shall submit such emission factor to PCAQCD for approval. The test-derived emission factor shall be calculated as the arithmetic mean of the emission factor results for all valid runs conducted as part of such performance test. The emission factor result for each run shall be calculated by dividing the measured emission rate during that run, expressed in lb/hr, by the heat input rate during that run, expressed in MMBtu/hr.

Appendix A – PCAQCD Permit Application Form

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:
   Salt River Project Agricultural Improvement and Power District (SRP)
   (Name and legal status (e.g. corporation or proprietorship) or organization that is to receive permit)

2. Mailing Address:
   P.O. Box 52025 PAB 359
   City: Phoenix State: Arizona Zip: 85072-2025
   Billing Address (if different from above):
   City: State: Zip:

3. Plant Name (if different from above): Marigold Energy Center

4. Name(s) of Owner or Operator: Salt River Project Agricultural Improvement and Power District
   Phone: 602-236-2322

5. Plant/Site Manager: Jace Kerby Phone: (602) 236-6320 Fax:

6. Contact Person: Jenn Paskash Phone: (602) 236-4746 Fax:
   Email Address: Jenn.Paskash@srpnet.com

7. Equipment/Plant Location or Proposed Location Address: NE corner of N Stanfield Road and West Barnes Road
   City: Stanfield Zip: 85172 Parcel #:
   Section/Township/Range: 5/06S/04E
   Latitude/Longitude: 32°55'37.86"N/111°57'27.18"W Elevation: 1,400 feet

8. General Nature of Business: Electricity Generating Station
   North American Industry Classification System: 221112

9. Type of Organization
   - ☐ Corporation State of Incorporation:
   - ☐ Arizona Limited Liability
   - ☐ Government Entity Government Facility Code:
   - ☐ Individual Owner
   - ☐ Partnership
   - ☑ Other (Specify): Agricultural Improvement District / Political Subdivision of the State of Arizona

10. Permit Application Basis: (Check all that apply)

- [x] New Source
- [ ] Permit Revision
- [ ] Administrative Change
- [ ] Renewal of Existing Permit
- [ ] Portable Source
- [ ] General Permit
- [ ] Permit Transfer

For renewal or modification, include existing permit number:

Date of Commencement of Construction or Modification: TBD

Is any of the equipment to be leased to another individual or entity? [ ] Yes [x] 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*** [x] ***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.

Jace Kerby

Signature of Responsible Official of Organization

Jace Kerby

Typed or Printed Name of Signer

Director

Official Title of Signer

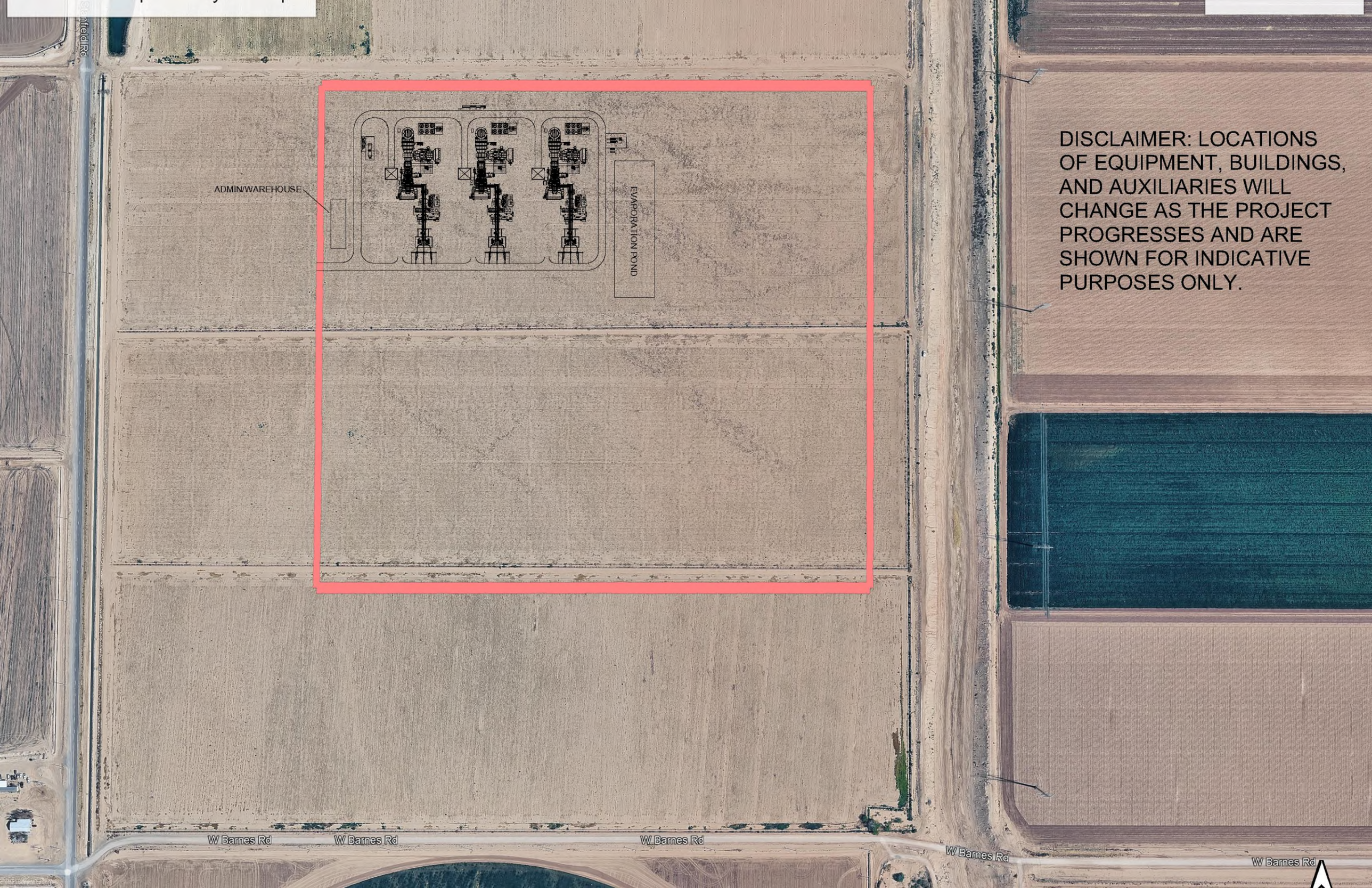
9/11/2026

Date

Fuel Burning Equipment Information

Equipment	Capacity (BTU/HR)	Fuel Type	Model #	Serial #	Manufacturer	Manufacturing Date
Simple Cycle CT	2,480,000,000	Natural Gas	GE 7F.05		GE	
Simple Cycle CT	2,480,000,000	Natural Gas	GE 7F.05		GE	
Simple Cycle CT	2,480,000,000	Natural Gas	GE 7F.05		GE	
Emergency Fire Pump	1,420,000	Diesel	JU6H-UFADNG		Clarke	

Appendix B – Site Layouts



DISCLAIMER: LOCATIONS OF EQUIPMENT, BUILDINGS, AND AUXILIARIES WILL CHANGE AS THE PROJECT PROGRESSES AND ARE SHOWN FOR INDICATIVE PURPOSES ONLY.

Appendix C – Emissions Calculations

Table 1: SRP Marigold Project -Stanfield AZ
Operating Scenario Inputs

Simple Cycle	GE 7F.05			
Number of Units	3			
Annual utilization factor	25%	each		
Annual operations per turbine	2,190	Hours/year		
SU/SD events, per CT	150	Number/year		
Start Duration	22	minutes		
Shutdown Duration	15	minutes		
Natural Gas (HHV)	1,015	Btu/cf		
Natural Gas (LHV)	914	Btu/cf		
Sulfur concentration in NG	0.5	gr/100 scf	0.002	lb of SO2/MMBtu
Per Part 75				
Lead Emission Factor	4.93E-07	lb/MMBtu		
Lead (Pb) emission factor is from the U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42 , 5th Edition, Table 1.4-2				
CH4 GWP	28			
N2O GWP	265			
40 CFR Part 98 Table A-1				

Table 2: SRP Marigold Project -Stanfield AZ
Simple Cycle Combustion Turbine

Proposed CT units	GE 7F.05	
EU ID	SCCT1, SCCT2, SCCT3	
Number of units	3	
Heat input	2,480	MMBtu/hour (HHV) 20F at site conditions
Output (gross)	225	MW estimate
SCR and CO Ox Cat	Yes	
Projected operation		
Annual operation	2,190	Hours per year based on 25% CF
Number of SU/SD for each CT	150	events/year
Startup duration for CT	0.37	hour
Shutdown duration for CT	0.25	hour
Heat input during events	670	MMBtu (HHV)/event
Worst case sulfur in NG	0.5	gr/100 cf 0.002 lb of SO2/MMBtu

	Normal - 1 CT		SU/SD Events - 1 CT		Total - 3 CT
Pollutants	lb/hour	TPY	lb/event	TPY	TPY
PM	7.2	7.9	7.2	0.5	25.3
PM10	14.4	15.8	14.4	1.1	50.5
PM2.5	14.4	15.8	14.4	1.1	50.5
SO2	5.0	5.4	1.3	0.1	16.6
NOx	22.4	24.5	115.4	8.7	99.5
VOC	6.3	6.9	71.6	5.4	36.8
CO	19.1	20.9	687.4	51.6	217.4
SAM	2.6	2.8	2.6	0.2	9.1
CO2e	340,281	372,607	340,281	25,521	1,194,386

SAM - sulfuric acid mist

Emission rates for all pollutants except GHGs based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load. Using the worst case rate for PTE estimate)

GHG (CO2e) EFs from Duke Cayuga permit in Indiana 165-47430-00001

Table 3: SRP Marigold Project -Stanfield AZ
Emergency Fire Pump

Proposed unit	Emergency Fire Pump		
EU ID	FP		
Number of units	1		
Expected operation	500	hours/year	
Power Output	190	bhp	Standby rating
	142	kW	
Fuel Consumption Rate	10	gal/hour	
Diesel heating value	138000	Btu/gallon	40 CFR Part 98 Table C-1
Heat Input Rate	1.42	MMBtu/hour	

Engine uncontrolled emission factors			
PM	0.20	g/kW-hr	Filterable only from NSPS IIII Table 4
PM10	0.24	g/kW-hr	Filterable from PM and Condensable from AP-42
PM2.5	0.24	g/kW-hr	Same as PM10
SO2	0.007	g/kW-hr	Assuming 15 ppm sulfur fuel (7.1 lb/gal)
NOx	4.0	g/kW-hr	NSPS Subpart IIII Table 4 (assumed no HC)
VOC	0.0025	lb/hp-hr	AP-42 Table 3.3-1
CO	3.5	g/kW-hr	NSPS Subpart IIII Table 4
PM condensable	0.0077	lb/MMBtu	AP-42 Table 3.4-2
SAM conversion	3%		Engineering estimate
CO2e	163.59	lb/MMBtu	40 CFR Part C-1 and C-2, GWP per 326 IAC 2-2-1(zz) from 78 FR 71

Potential to Emit:

Pollutant	Short Term (lb/hour)	Annual (tons/year)
PM	0.1	0.0
PM10	0.1	0.0
PM2.5	0.1	0.0
SO2	0.0	0.0
NOx	1.2	0.3
VOC	0.5	0.1
CO	1.1	0.3
SAM	6.6E-05	1.6E-05
CO2e	233	58

CO2e based on 2025 GWP in 40 CFR 98 Subpart A Table A-1

Table 4: SRP Marigold Project -Stanfield AZ
Project Emissions Increases

2027 Marigold Project Emissons Increases (PTE of new emission units)

	Emissions (TPY)				
Pollutant	Unit 20	FP1	Total	Major Source	Whether Major Source?
PM	25.3	0.0	25.3	250	No
PM10	50.5	0.0	50.6	70	No
PM2.5	50.5	0.0	50.6	100	No
SO2	16.6	0.0	16.6	100	No
NOx	99.5	0.3	99.9	100	No
VOC	36.8	0.1	36.9	250	No
CO	217.4	0.3	217.7	250	No
SAM	9.1	0.0	9.1	250	No
CO2e	1,194,386	58	1,194,444	75,000	NA

Table 5: SRP Marigold Project -Stanfield AZ
Hazardous Air Pollutant (HAP) information for CTs

	CTs	
NG heat input (MMBtu/hour)	2,480	MMBtu/hr
Number of units	3	
Annual utlization (normal)	2,190	hours
Annual utlization (SU/SD)	93	hours

HAPs emission factors	lb/MMBtu	
Acetaldehyde	4.0E-05	AP-42 Table 3.1-3, 4/2000
Acroliein	6.4E-06	AP-42 Table 3.1-3, 4/2000
Benzene	1.2E-05	AP-42 Table 3.1-3, 4/2000
Ethylbenzene	3.2E-05	AP-42 Table 3.1-3, 4/2000
Formaldehyde	7.1E-04	AP-42 Table 3.1-3, 4/2000
Hexane	2.5E-04	BAAQMD TAC Emission Factor Guidelines, 8/2020
Napthalene	1.3E-06	AP-42 Table 3.1-3, 4/2000
PAH	2.2E-06	AP-42 Table 3.1-3, 4/2000
Toluene	1.3E-04	AP-42 Table 3.1-3, 4/2000
Xylene	6.4E-05	AP-42 Table 3.1-3, 4/2000

Conservative control efficiency for other HAPs 50%

	Emissions (TPY)	
HAPs PTE	One CT	Total for 3 CTs
Acetaldehyde	5.9E-02	0.2
Acroliein	9.4E-03	0.0
Benzene	1.8E-02	0.1
Ethylbenzene	4.7E-02	0.1
Formaldehyde	1.0	3.1
Hexane	0.4	1.1
Napthalene	1.9E-03	0.0
PAH	3.2E-03	0.0
Toluene	1.9E-01	0.6
Xylene	9.4E-02	0.3
Total HAPs	1.8	5.5

Table 6: **SRP Marigold Project -Stanfield AZ**
HAPs for Diesel FP1

Parameters:	FP	
Engine Heat Input:	1.42	MMBtu/hour
Max Annual Hours:	500	hour/year
Annual Heat Input:	711	MMBtu/year

HAPs emission factors	lb/MMBtu	
Acetaldehyde	2.5E-05	AP-42 Table 3.4-3, 10/1996
Acroliein	7.9E-06	AP-42 Table 3.4-3, 10/1996
Benzene	7.8E-04	AP-42 Table 3.4-3, 10/1996
Formaldehyde	7.89E-05	AP-42 Table 3.4-3, 10/1996
Hexane	1.05E-05	California Air Toxics Emission Factor
Napthalene	1.3E-04	AP-42 Table 3.4-4, 10/1996
PAH	2.1E-04	AP-42 Table 3.4-4, 10/1996
Toluene	2.81E-04	AP-42 Table 3.4-3, 10/1996
Xylene	1.93E-04	AP-42 Table 3.4-3, 10/1996

HAPs PTE	FP Emissions (TPY)
Acetaldehyde	9.0E-06
Acroliein	2.8E-06
Benzene	2.8E-04
Formaldehyde	2.8E-05
Hexane	3.7E-06
Napthalene	4.6E-05
PAH	7.5E-05
Toluene	1.0E-04
Xylene	6.9E-05
Total HAPs	6.1E-04

Table 7: **SRP Marigold Project -Stanfield AZ**
HAPs Summary

HAPs PTE	Emissions (TPY) Total for 3 CTs	FP	Total
Acetaldehyde	1.8E-01	9.0E-06	0.2
Acroliein	2.8E-02	2.8E-06	0.0
Benzene	5.3E-02	2.8E-04	0.1
Ethylbenzene	1.4E-01		0.1
Formaldehyde	3.1	2.8E-05	3.1
Hexane	1.1	3.7E-06	1.1
Napthalene	5.7E-03	4.6E-05	0.0
PAH	9.7E-03	7.5E-05	0.0
Toluene	5.7E-01	1.0E-04	0.6
Xylene	2.8E-01	6.9E-05	0.3
Total HAPs	5.5	6.1E-04	5.5

Appendix D – Copy of Acid Rain Permit Application

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 12/31/2021

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☑ **new** ☐ **revised** ☐ **for ARP permit renewal**

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Marigold Energy Center	Arizona	

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
SCCT1	Yes
SCCT2	Yes
SCCT3	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Marigold Energy Center
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
   (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
   (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
   (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
   (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
   (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
   (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
   (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
   (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Marigold Energy Center
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
   (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
   (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
   (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Marigold Energy Center
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Zachary Harbin	
Signature	Date 9/11/26

Appendix E – Air Quality Modeling Report

AIR DISPERSION MODELING REPORT FOR THE SALT RIVER PROJECT MARIGOLD ENERGY CENTER STANFIELD, ARIZONA

Delivering water and power®

Prepared for:
Salt River Project
P.O. Box 52025, M/S: PAB359
Phoenix, Arizona 85072-2025

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

September 2026

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1.0 INTRODUCTION

This document presents the results of the air quality dispersion modeling analysis conducted for Salt River Project Agricultural Improvement and Power District ("SRP") to construct and operate a natural gas-fired simple cycle power plant ("Thermal Plant Project" or "Project") near Stanfield in Pinal County, Arizona at the proposed Marigold Energy Center ("MEC").

While the modeling analysis of the Thermal Plant Project's emissions is not required under the Prevention of Significant Deterioration ("PSD") or Pinal County's minor New Source Review ("NSR") regulations, SRP has elected to perform air emissions dispersion modeling as part of their application. The analysis was conducted to characterize, for each pollutant for which there is a National Ambient Air Quality Standard ("NAAQS"), the effects on ambient air quality that could result from the Project.[a]

The analysis conformed with the modeling procedures outlined in the U.S. Environmental Protection Agency's ("USEPA") Guideline on Air Quality Models[1] ("Guideline" or "Appendix W"), the Arizona Department of Environmental Quality ("ADEQ") Air Quality Modeling Guidelines for Arizona Air Quality Permits[2], and associated modeling policy and guidance.

[a] Criteria pollutants such as SO_2 were not included in the analysis because the project emissions increase is below the significant emission rate under PSD.

2.0 PROJECT DESCRIPTION

SRP is proposing to construct the Project on approximately 60 acres of SRP-owned property, north of W. Barnes Road and east of N. Stanfield Road near Stanfield in Pinal County, Arizona. The proposed facility design includes three (3) frame-type combustion turbines (“CT”), each of which will drive an electricity generator, and a diesel fire pump.

3.0 SITE DESCRIPTION

The Thermal Plant Project will be located approximately 5 kilometers (3 miles) to the north-northeast of Stanfield. The approximate Universal Transverse Mercator ("UTM") coordinates of the facility are 410,294 meters east and 3,643,565 meters north (UTM Zone 12, North American Datum 83 ("NAD83")). The facility is approximately 390 meters (1,280 feet) above mean sea level. Figure 1 shows the general location of the facility. Figure 2 shows the specific location of the facility on a U.S. Geological Survey ("USGS") topographic map.

The Project site is located within the Pinal County 'serious' PM_{10} nonattainment area and also within the West Central Pinal 'moderate' $PM_{2.5}$ nonattainment area. The area is classified as attainment or unclassified for all other criteria pollutants as codified at 40 CFR 81.303.

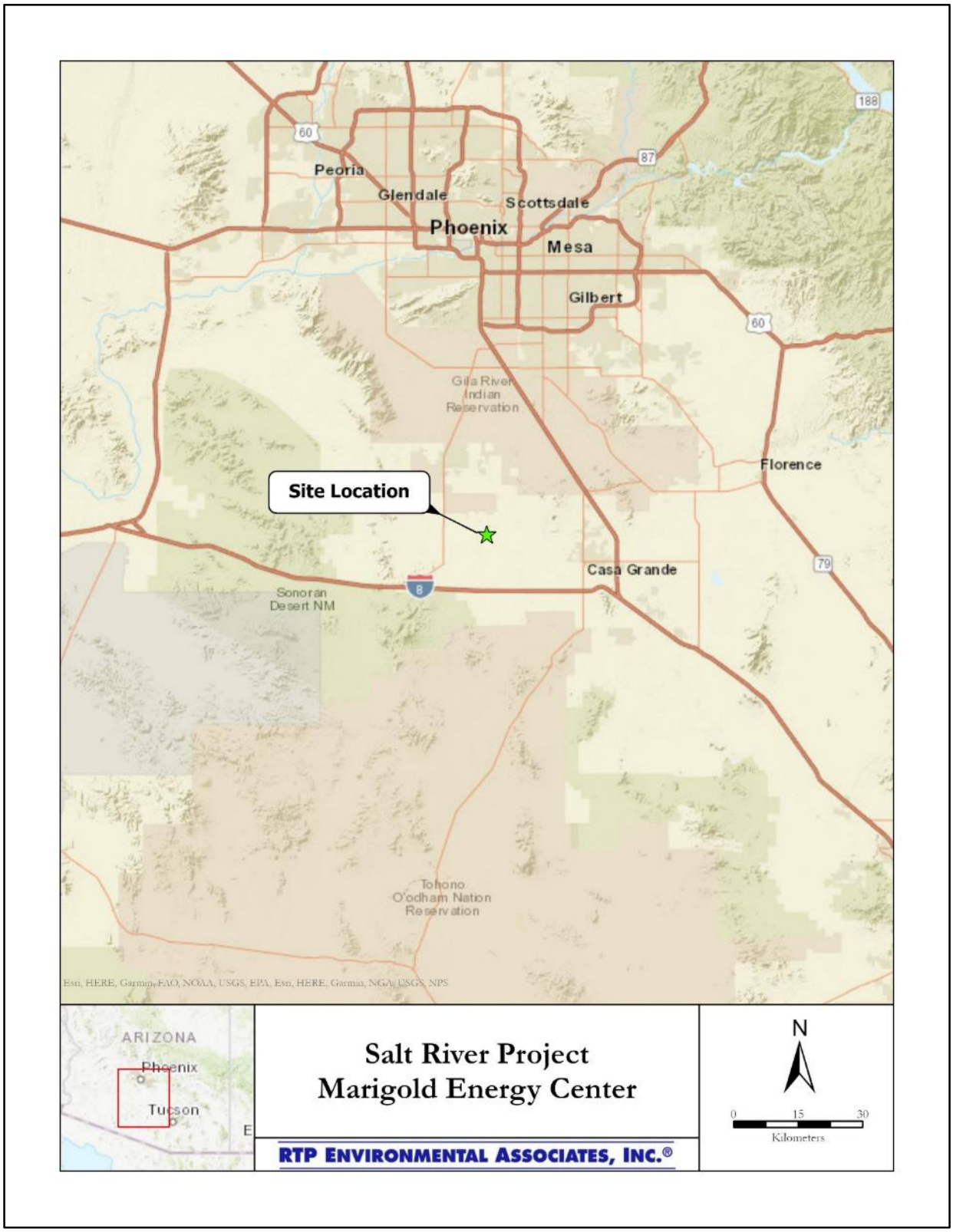


Figure 1. General Location of MEC

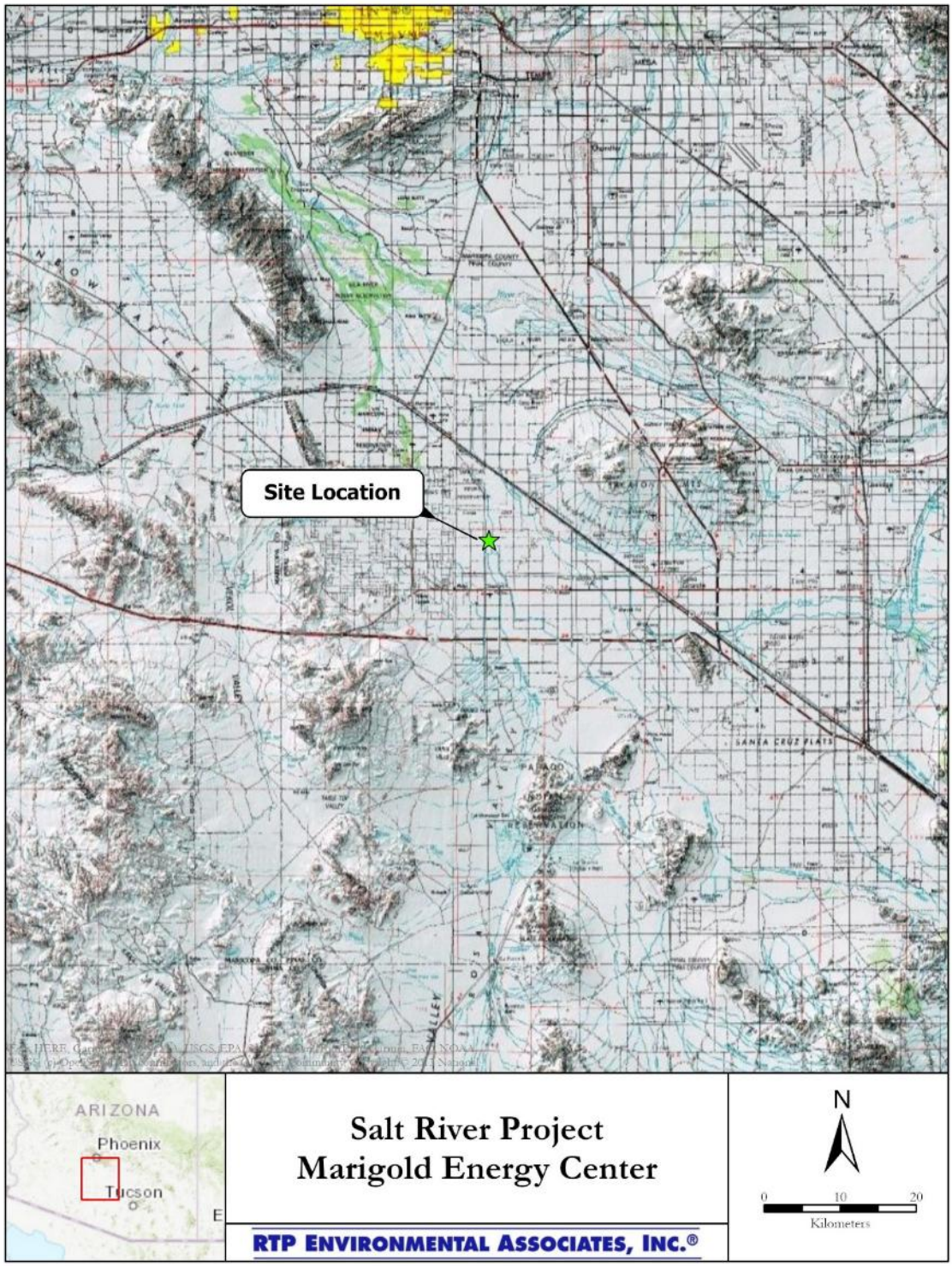


Figure 2. Specific Location of MEC

4.0 MODEL SELECTION AND MODEL INPUT

4.1 Model Selection

The latest version of the AMS/EPA Regulatory Model (AERMOD, Version 26135) was used in the dispersion modeling analysis. AERMOD is a Gaussian plume dispersion model that is based on planetary 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.

AERMOD is the required model for calculating ambient concentrations near the Thermal Plant Project based on the model's ability to incorporate multiple sources and source types. The model can also account for convective updrafts and downdrafts and meteorological data throughout the plume depth. The model also provides parameters required for use with up-to-date planetary boundary layer parameterization. The model has the ability to incorporate building wake effects and to calculate concentrations within the cavity recirculation zone. All model options were selected as recommended in the USEPA Guideline on Air Quality Models.

Providence Oris's BEEST Graphical User Interface (“GUI”) was used to run AERMOD. The GUI uses an unaltered version of the AERMOD code. Therefore, a model equivalency evaluation pursuant to Section 3.2 of 40 CFR 51, Appendix W is not warranted.

4.2 Model Control Options and Land Use

AERMOD was run in the regulatory default mode. The default rural dispersion coefficients in the model were used. This is supported by the Land Use Procedure consistent with subsection 7.2.1.1(b) of the Guideline and Section 5.1 of the AERMOD

Implementation Guide. The USGS 2024 National Land Cover Data ("NLCD") within 3km of the site were converted to Auer 1978 land use types and evaluated (Figure 3 and Table 1). It was determined that the land use in the vicinity of the site is comprised predominantly of cultivated crops; with 1% defined as urban (NLCD categories 23 and 24). The area surrounding the facility was therefore determined to be rural as defined by Auer (i.e., less than 50% of the area is classified as urban).

Table 1. Land-Use Classification

2019 NLCD Classification		Area (Acres)	Percentage of Total Area	Auer Land-Use Classification		Rural or Urban
11	Open Water	15	0.2%	A5	Water surfaces	Rural
12	Perennial Ice/Snow	0.0	0.0%	A5	Water surfaces	Rural
21	Developed, Open Space	582	8.3%	A1	Metropolitan Natural	Rural
22	Developed, Low Intensity	121	1.7%	R1	Common Residential	Rural
23	Developed, Medium Intensity	55	0.8%	I1, I2, C1, R2, R3	Industrial/Commercial/Compact Residential	Urban
24	Developed, High Intensity	20	0.3%	I1, I2, C1, R2, R3	Industrial/Commercial/Compact Residential	Urban
31	Barren Land	5	0.1%	A3	Undeveloped (Grasses/Shrub)	Rural
41	Deciduous Forest	0	0.0%	A4	Undeveloped (Wooded)	Rural
42	Evergreen Forest	0	0.0%	A4	Undeveloped (Wooded)	Rural
43	Mixed Forest	0	0.0%	A4	Undeveloped (Wooded)	Rural
52	Shrub/Scrub	391	5.6%	A3	Undeveloped (Grasses/Shrub)	Rural
71	Grassland/Herbaceous	130	1.9%	A3	Undeveloped (Grasses/Shrub)	Rural
81	Pasture/Hay	0	0.0%	A2	Agricultural	Rural
82	Cultivated Crops	5,666	81.1%	A2	Agricultural	Rural
90	Woody Wetlands	0	0.0%	A4	Undeveloped (Wooded)	Rural
95	Emergent Herbaceous Wetlands	0	0.0%	A3	Undeveloped (Grasses/Shrub)	Rural
Urban Total		**74**	**1.1%**			

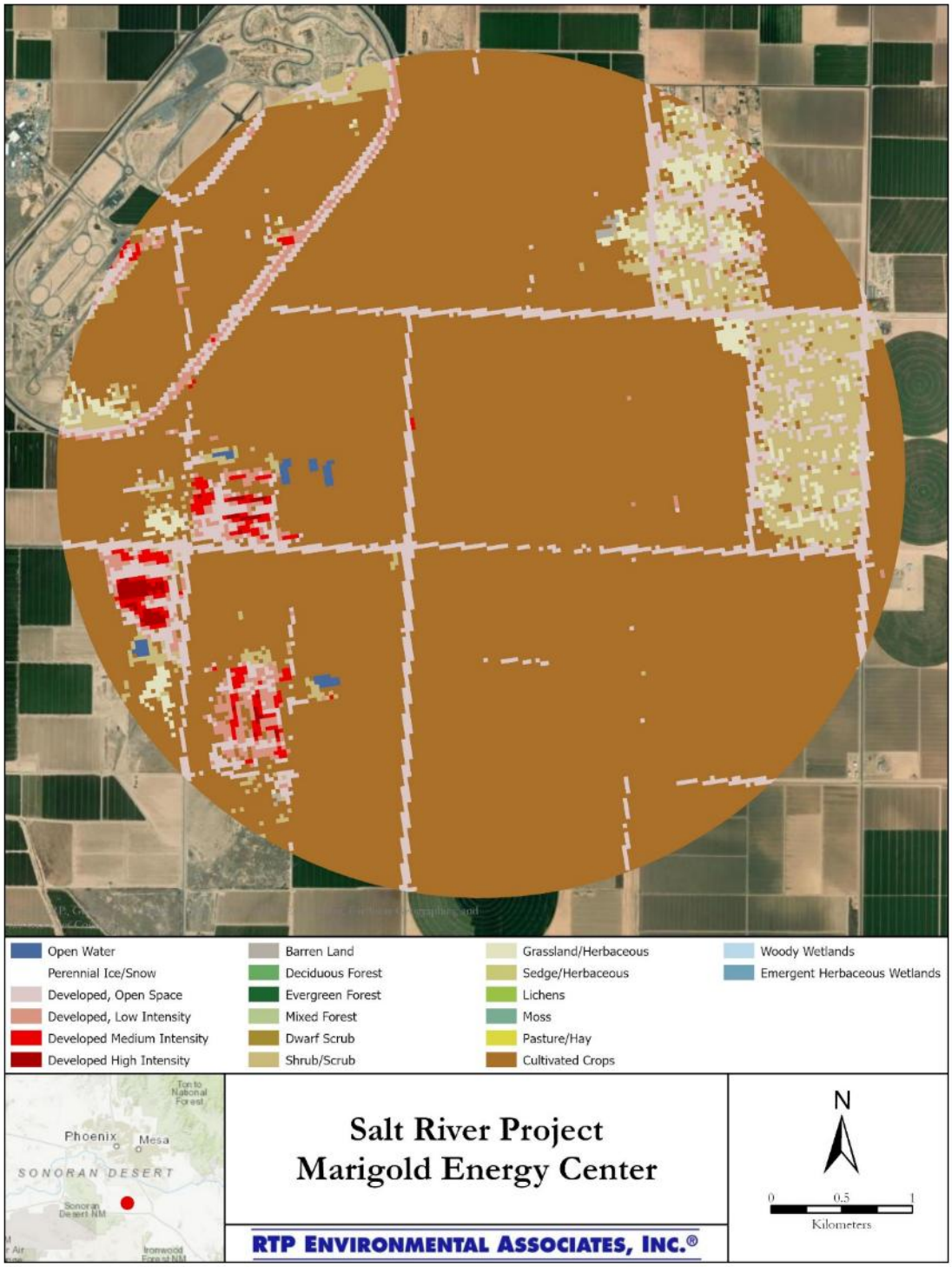


Figure 3. Land Use within Three Kilometers of MEC

4.3 Source Data

Source Characterization

Emission sources at the site will consist of three (3) CTs and one (1) emergency fire pump. All sources will vent to vertically orientated stacks with a well defined, unobstructed opening, and are modeled as point sources.

All source locations are based upon a NAD83, UTM Zone 12 projection.

Good Engineering Practice Stack Height Analysis

A Good Engineering Practice ("GEP") stack height evaluation was conducted to determine appropriate building dimensions to include in the model. Procedures to be used are in accordance with those described in the USEPA Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations-Revised)[3]. GEP formula stack height, as defined in and Pinal County Code § 3-1-177(B), is expressed as $H_g = H + 1.5L$, where H_g is the GEP stack height, H is the building height, and L is the lesser dimension (height or projected width) of the building. Building/structure locations are determined from a preliminary facility plot plan. The structure locations and heights were input to the USEPA's Building Profile Input Program (BPIP-PRIME, Version 04274) computer program to calculate the direction-specific building dimensions needed for AERMOD.

A depiction of the modeled layout of sources and buildings is shown in Figure 4.

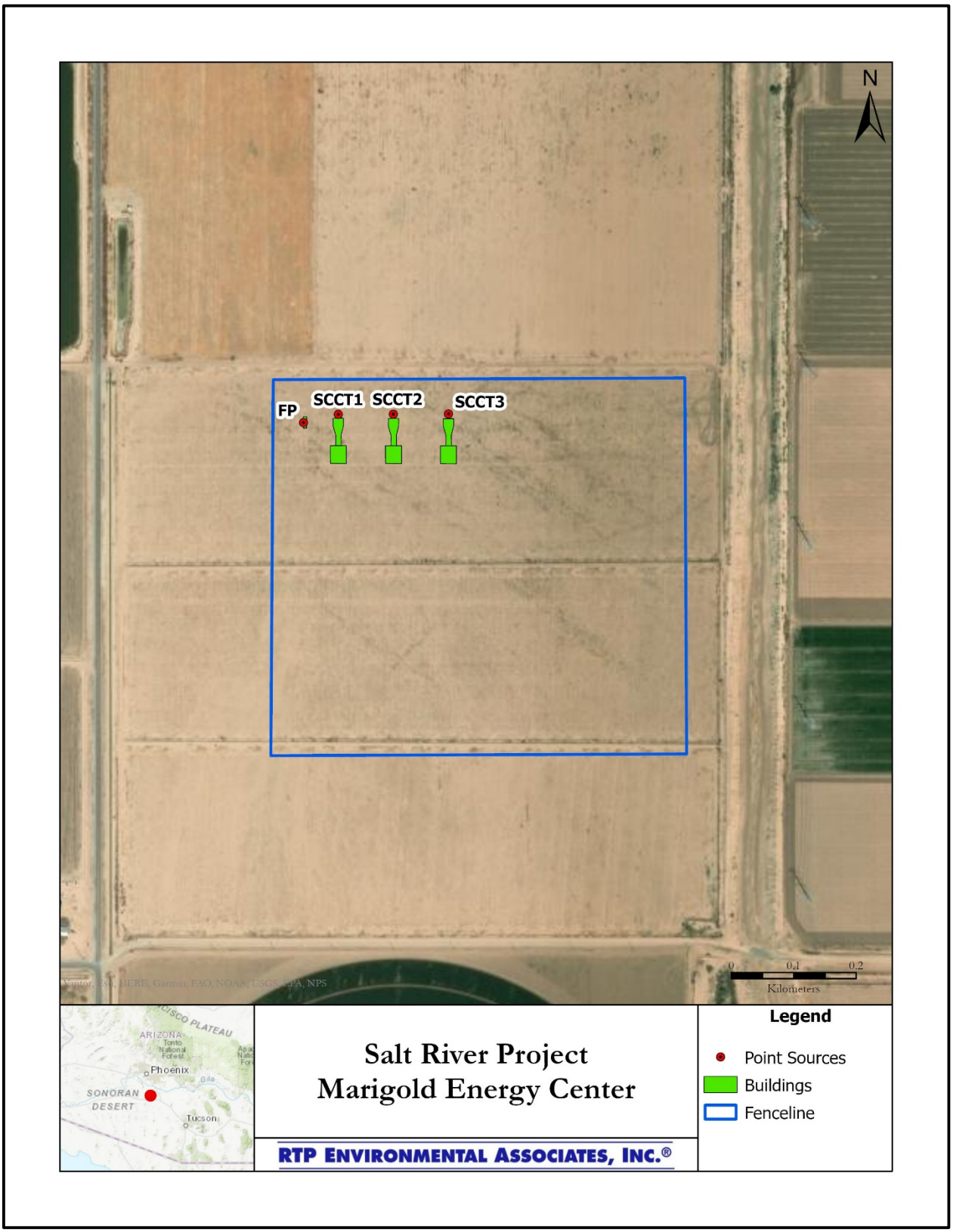


Figure 4. Modeled Layout

4.4 Receptor Data

Modeled receptors were placed in all areas considered as "ambient air." Ambient air is defined in Pinal County Code § 1-3-140(13) as that portion of the atmosphere, external to buildings, to which the general public has access. A physical fence will be used as the ambient air boundary in the analysis and is shown in Figure 4. The receptor grid consists of the following:

1. Receptors spaced along the fenceline at 25m intervals,
2. A find grid of receptors with 100m spacing extending to 2.5km from the fenceline,
3. A medium grid of receptors with 250m spacing extending from 2.5km to 5km,
4. A medium grid of receptors with 500m spacing extending from 5km to 10km,
5. A coarse grid of receptors with 1,000m spacing extending from 10 to 20km,
6. A very coarse grid of receptors with 2,000m spacing extending from 20 to 50km.

MEC is located in south central Arizona. Terrain within 10km of MEC is relatively flat. However; beyond 10km, the terrain becomes complex. Receptor elevations and hill height scale factors were calculated with AERMAP (24142). The one arc second National Elevation Data (“NED”) obtained from the USGS was used. Locations were based upon a NAD83, UTM Zone 12 projection. The near-field receptor grid is presented in Figure 5.

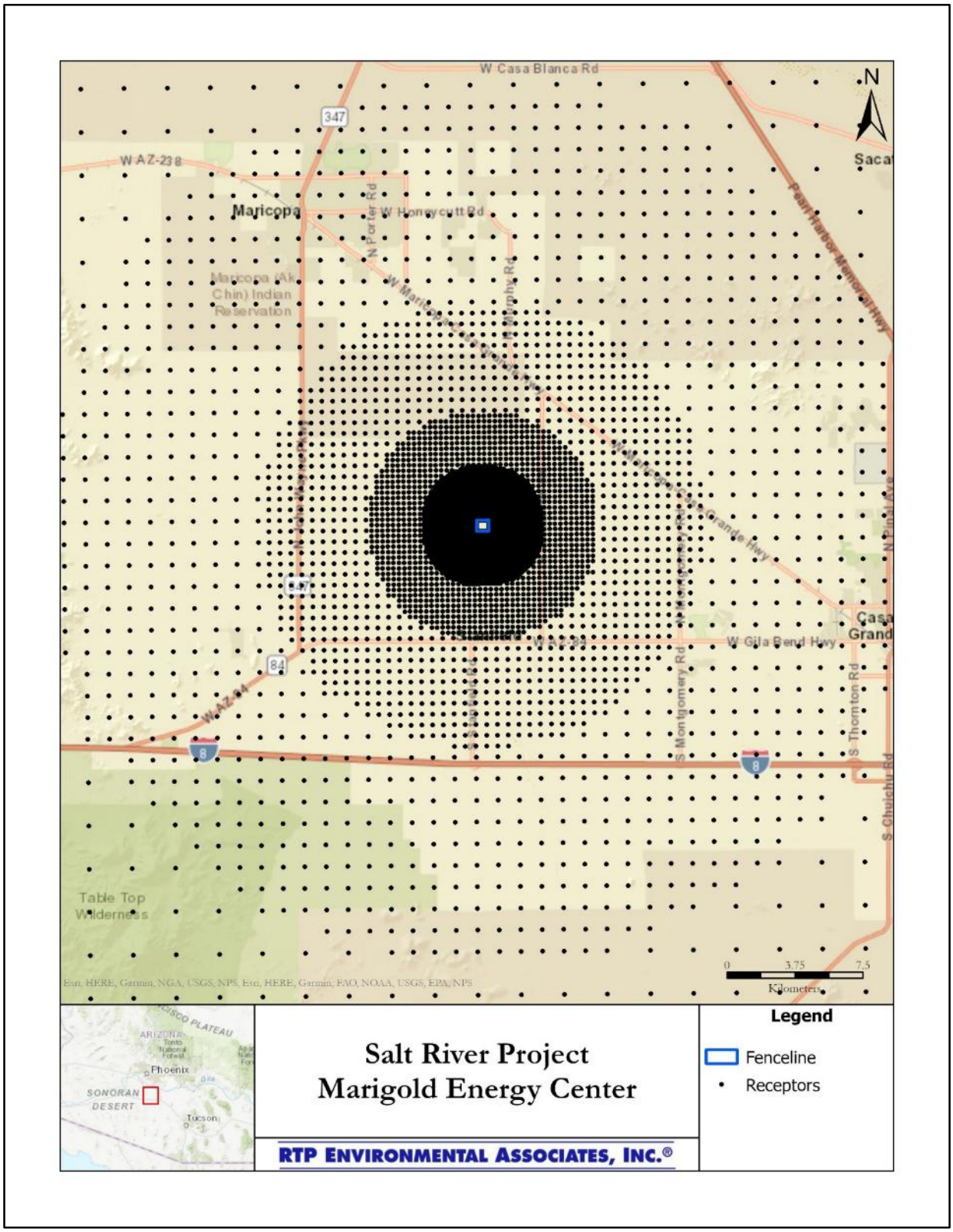


Figure 5. Near-field Receptor Grid

4.5 Meteorological Data

The 2020-2024, 5-year sequential hourly surface meteorological data collected at the Phoenix Sky Harbor International Airport (KPHX, WBAN 23183) and upper air data from the Tucson International Airport (KTUS, WBAN 23160) were used in the analysis. Data from both meteorological stations were processed by ADEQ using AERMET version 24142. ADEQ used the surface friction velocity adjustment (adj u*) in processing the data.

There are four criteria in the Guideline for assessing whether meteorological data are representative of the study area. These criteria include: 1) proximity of the meteorological station to the area under consideration, 2) the complexity of the terrain, 3) the exposure of the meteorolgical site, and 4) the period of time during which the data are collected.

The Sky Harbor data have been evaluated relative to these criteria and determined to be representative of the MEC modeling domain. Sky Harbor is located approximately 56km to the north of MEC as shown in Figure 6. There are no significant terrain features between the two sites that would affect wind direction and thus significantly alter the dispersion patterns experienced at each location. The Sky Harbor tower is also free of any obstructions as it was established as a National Weather Service 1st Order Station that must meet specific site and exposure standards. In addition, the most current five year dataset as provided by the ADEQ was employed. As a result, the Phoenix data adequately represent the meteorological conditions experienced in the MEC modeling domain. The 2020-2024 wind rose is provided in Figure 7.

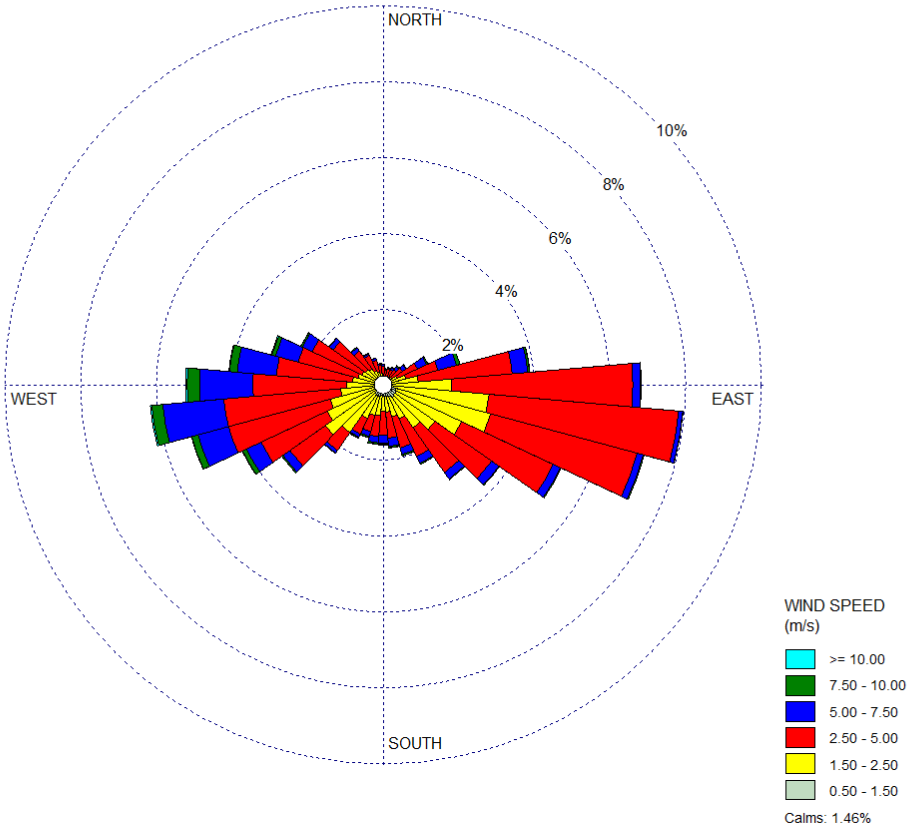
Figure 6. Location of Meteorological Stations

WIND ROSE PLOT:

Station #23183 - PHOENIX/SKY HARBOR INT'L ARPT, AZ

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	Start Date: 1/1/2020 - 00:00 **End Date: 12/31/2024 - 23:59**	**RTP Environmental Associates, Inc.**	
		MODELER: **Andy Holland**	RTP ENVIRONMENTAL ASSOCIATES, INC.©
	CALM WINDS: **1.46%**	TOTAL COUNT: **43572 hrs.**	
	AVG. WIND SPEED: **3.25 m/s**	DATE: **7/10/2026**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 7. 2020-2024 Wind Rose

5.0 MODELING METHODOLOGY AND RESULTS

5.1 Modeled Pollutants

Emissions of carbon monoxide ("CO"), nitrogen dioxide ("NO_2"), particulate matter ("PM") with a diameter less than or equal to 10 micrometers ("PM_{10}"), and PM with a diameter less than or equal to 2.5 micrometers ("$PM_{2.5}$") were included in the analysis.

5.2 Load Analysis

A load analysis was performed for the new CTs to determine the worst-case stack parameters and operating conditions. Rather than model each of the potential combinations of ambient temperature and operating loads, a simplified yet conservative analysis was performed by modeling worst-case stack temperature and flow rates over ambient temperatures for each load.

The minimum stack gas temperature and velocity was modeled for each load. The emission rates modeled for each load were normalized to the emission rate of the 100% load. Therefore, the emission rate for the 100% load was 1 lb/hr, emission rates for the lower loads were less than 1 lb/hr, and the emission rate for the startup/shutdown load was much greater than 1 lb/hr. The emission rates and stack parameters for the load analysis are shown in Table 2.

Table 2. Load Analysis Stack Parameters and Emissions

Source ID	Release Type	Source Description	Easting (m)	Northing (m)	Base Elevation (ft)	Stack Height (ft)	Temperature (°F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	Emission Rate (lb/hr)
GEF_100	DEFAULT	100% Load	4100290.23	3643889.62	1267.62	130	850.0	101.4	26.0	1.00
GEF_75	DEFAULT	75% Load	4100290.23	3643889.62	1267.62	130	850.0	88.7	26.0	0.85
GEF_50	DEFAULT	50% Load	4100290.23	3643889.62	1267.62	130	850.0	77.4	26.0	0.70
GEF_46	DEFAULT	46% Load	4100290.23	3643889.62	1267.62	130	850.0	79.2	26.0	0.68
GEF_43	DEFAULT	43% Load	4100290.23	3643889.62	1267.62	130	850.0	77.0	26.0	0.56
GEF_38	DEFAULT	38% Load	4100290.23	3643889.62	1267.62	130	850.0	74.9	26.0	0.54
GEF_SU	DEFAULT	Startup	4100290.23	3643889.62	1267.62	130	850.0	74.9	26.0	28.82

The results of the load analysis are shown in Table 3. The startup load resulted in the maximum modeled impacts for all averaging periods. Therefore, the stack parameters for that load were conservatively used in all further analyses.

Table 3. Load Analysis Results

Load Level	Averaging Period	Maximum Modeled Concentration (µg/m^3)
100%	1-hour	0.0703
75%		0.0618
50%		0.0526
46%		0.0503
43%		0.0422
38%		0.0414
Startup		**2.2115**
100%	8-hour	0.0169
75%		0.0162
50%		0.0151
46%		0.0143
43%		0.0121
38%		0.0120
Startup		**0.6378**
100%	24-hour	0.0065
75%		0.0064
50%		0.0060
46%		0.0057
43%		0.0048
38%		0.0048
Startup		**0.2561**
100%	Annual	0.0013
75%		0.0013
50%		0.0012
46%		0.0011
43%		0.0009
38%		0.0009
Startup		**0.0493**

5.3 Significant Impact Analysis

The criteria pollutant air quality analysis was conducted in two phases: an initial or significant impact analysis, and a refined phase including a NAAQS analysis, if required.

The significant impact analysis included only the sources included in the Project. Modeled stack parameters are shown in Table 4 and modeled emissions are shown in Table 5.

CT Emission Rates

The modeled emissions for each CT were equal to the maximum emission rate over all operating loads for each pollutant and averaging period. Therefore, startup emissions were conservatively modeled for each hour for all averaging periods.

Intermittent Emissions

The Project equipment include a fire pump engine that will only be operated for testing/maintenance purposes outside of emergency operation. ADEQ has developed guidance on how to include these intermittent sources in the 1-hour NO_2 analysis; these sources are modeled using the annualized average emission rates, assuming 500 hours per year of non-emergency operation. However, the intermittent source guidance does not extend to the 24-hour PM_{10} and $PM_{2.5}$ analyses. For those analyses, the fire pump engine was conservatively assumed to be tested no more than 2 hours per day and 500 hours per year.

Table 4. Significant Impact Analysis Stack Parameters

Source ID	Release Type	Source Description	Easting (m)	Northing (m)	Base Elevation (ft)	Stack Height (ft)	Temperature (°F)	Exit Velocity (ft/sec)	Stack Diameter (ft)
SCCT1	DEFAULT	Simple Cycle Turbine – Startup	410216.23	3643889.99	1267.49	130.0	850	74.9	26.0
SCCT2	DEFAULT	Simple Cycle Turbine – Startup	410290.23	3643889.62	1267.62	130.0	850	74.9	26.0
SCCT3	DEFAULT	Simple Cycle Turbine – Startup	410364.53	3643889.24	1267.75	130.0	850	74.9	26.0
FP	DEFAULT	Emergency fire pump	410169.34	3643879.42	1267.42	13.0	855.0	184.1	0.42

Table 5. Significant Impact Analysis Emission Rates

Source ID	Emission Rate (lb/hr)					
	CO	NO_2 1-hr	NO_2 Annual	PM_{10}	$PM_{2.5}$ 24-hr	$PM_{2.5}$ Annual
SCCT1	409.08	93.12	93.12	14.40	14.40	14.40
SCCT2	409.08	93.12	93.12	14.40	14.40	14.40
SCCT3	409.08	93.12	93.12	14.40	14.40	14.40
FP	1.09	0.07	0.07	0.006	0.006	0.004

Maximum modeled concentrations were compared to the significant impact levels ("SILs"), as defined in PCC 3-1-030(19) or as specified by the USEPA guidance for developing air quality dispersion modeling. The results of the significant analysis are shown in Table 6. Note that the secondary $PM_{2.5}$ contribution is also included in the SIL analysis results. The secondary $PM_{2.5}$ analysis results are discussed in the next section.

The proposed Project results in significant impacts only for 1-hour NO_2. A cumulative analysis was therefore conducted for the 1-hour NO_2 NAAQS.

Table 6. Class II Significant Impact Analysis Results

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)	Secondary PM2.5 Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	PSD Class II SIL ($\mu g/m^3$)	% of SIL
CO	1-hour	108.79	--	108.79	2,000	5%
	8-hour	95.88	--	95.88	500	19%
NO_2	1-hour	16.31	--	16.31	7.5	217%
	Annual	0.59	--	0.59	1.0	59%
PM_{10}	24-hr	0.38	--	0.38	5.0	8%
$PM_{2.5}$	24-hr	0.32	0.018	0.33	1.2	28%
	Annual	0.064	0.0002	0.064	0.13	49%

5.4 Secondary $PM_{2.5}$ Analysis

ADEQ's minor-NSR modeling guidance does not explicitly require the consideration of secondary $PM_{2.5}$ impacts. However, to be conservative, it was included in this modeling analysis.

On July 29, 2022, USEPA issued final guidance for assessing ozone and fine particulate matter modeling[4]. 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 $PM_{2.5}$. Secondary impacts refer to the $PM_{2.5}$ impacts attributable to nitrates and sulfates formed due to precursor NOx and SO_2 emissions. The USEPA guidance provides procedures including the Tier 1 Modeled Emission Rate for Precursors ("MERPs") procedure[5] for calculating secondary $PM_{2.5}$ impacts.

The direct $PM_{2.5}$ emissions were modeled using approved dispersion techniques and the MERPs approach was used to estimate the secondary $PM_{2.5}$ contribution from both NOx and SO_2 emissions. Representative MERPs values for the hypothetical source in La Paz County, Arizona were used, as they are deemed to be the most representative of the modeling domain due to it being located in the same lowland Sonoran Desert ecosystem as MEC.

The results of the secondary $PM_{2.5}$ analysis are shown in Table 7. The hypothetical source had emissions of 500 tons per year of NOx and SO_2 and a release height of 10 meters.

The contribution of each precursor was calculated by dividing the maximum impact of the hypothetical source by the hypothetical source's emissions, then multiplying that by the Project emissions. These calculated contributions were then added to the maximum modeled concentrations before comparison to the SILs.

Table 7. Secondary $PM_{2.5}$ Analysis Results

Precursor	Project Emissions (tpy)	Max 24-hr Impact of Hypothetical Source (µg/m³)	Max Annual Impact of Hypothetical Source (µg/m³)	24-hr Contribution (µg/m³)	Annual Contribution (µg/m³)
NO_x	99.9	0.0393	0.0004	0.008	0.0001
SO_2	16.6	0.3128	0.0032	0.010	0.00011
Total Secondary Contribution				0.018	0.0002

5.5 Single-Source Ozone Impact Analysis

ADEQ's minor-NSR modeling guidance does not explicitly require the consideration of single-source ozone impacts. However, to be conservative, it was included in this modeling analysis.

USEPA's guidance not only addresses secondary $PM_{2.5}$ impacts, but also ozone impacts. The USEPA guidance provides procedures including the Tier 1 MERPs procedure for calculating single-source ozone impacts.

The MERPs approach was used to estimate the single-source ozone contribution from both NOx and volatile organic compounds ("VOCs") emissions. Representative MERPs values for the hypothetical source in La Paz County, Arizona were used, as they are deemed to be the most representative of the modeling domain due to it being located in the same lowland Sonoran Desert ecosystem as MEC.

The results of the ozone SIL analysis are shown in Table 8. The contribution of each precursor was calculated in the same manner as the secondary $PM_{2.5}$ analysis.

Table 8. Ozone SIL Analysis Results

Precursor	Project Emissions (tpy)	Max 8-hr Impact of Hypothetical Source (ppb)	8-hr Contribution (ppb)
NO_x	99.9	2.336	0.47
VOC	36.9	0.0208	0.002
Total Secondary Contribution			0.47

As shown, the calculated value is less than the 1 ppb SIL for ozone; therefore, compliance with the ozone NAAQS has been demonstrated.

5.6 NAAQS Analysis

Following the determination of significant impacts, a refined air quality analysis to determine compliance with the NAAQS was conducted. This analysis was conducted to determine compliance with the 1-hour NO_2 NAAQS. The receptors modeled in the NAAQS analyses were limited to those showing a significant impact. The same emission rates used in the significance analysis were used in the NAAQS analysis.

Background Concentrations

Pursuant to ADEQ Air Quality Modeling Guidelines, representative background pollutant concentrations should be combined with the Project's modeled concentrations in a minor NSR NAAQS analysis. SRP has conservatively elected to follow this guidance even though this project is not subject to ADEQ's minor NSR regulations.

Ambient background pollutant concentrations are used to establish representative background concentrations to complete the refined NAAQS analysis. The background concentrations were added to the modeled concentrations to assess NAAQS compliance.

Instead of determining the most representative ambient monitor, SRP conservatively elected to use the highest 2023-2025 1-hour NO_2 monitored design value in Arizona (Table 9). The selected ambient monitor is in the heart of the Phoenix metropolitan area, where the NO_2 emissions density is much greater than that near the Project site in rural Pinal County.

Table 9. Background Pollutant Concentration

Pollutant	Averaging Time	Value (µg/m^3)	Station Name	AQS Site No.
NO_2	1-hour	109 (58 ppb)	Thirty-Third (Phoenix)	04-013-4020

NAAQS Compliance Assessment

The modeled and monitored values shown in Table 10 were used for this assessment. Model results are shown in Table 11. As shown, modeled concentrations are below the NAAQS.

Table 10. Monitored and Modeled Values Used to Assess NAAQS Compliance

Pollutant	Averaging Time	Monitored Value	Modeled Value
NO_2	1-hour	98th percentile of the annual distribution of daily maximum 1-hour values averaged over three years	98th percentile of the annual distribution of daily maximum 1-hour values averaged over five years

Table 11. NAAQS Analysis Results

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)[a]	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1-hour	12.35	109	121.39	188

5.7 Learning Sites Policy

ADEQ has established the Learning Sites Policy to ensure that children at learning sites are protected from criteria 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 closest learning site to the Project site is Stanfield Elementary School located approximately 3 miles to the south. Therefore, the Project is not subject to the Policy.

6.0 MODEL INPUT AND OUTPUT FILES

Computer generated modeling results files as well as all model and BPIP input files will be submitted electronically.

REFERENCES

1. Guideline on Air Quality Models. Appendix W of 40 CFR Part 51, 82 FR 5182, November 29, 2024.

2. Air Quality Modeling Guidelines for Arizona Air Quality Permits. Facilities Emissions Control Section, Air Quality Division, Arizona Department of Environmental Quality, November 1, 2019.

3. Guideline for Determination of Good Engineering Practice Stack Height (Technical Support Document for Stack Height Regulations (Revised). EPA-450/4-80-023R, U.S. Environmental Protection Agency, June 1985.

4. USEPA, Guidance for Ozone and Fine Particulate Matter Permit Modeling, July 29, 2022.

5. USEPA, Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program, April 30, 2019.