EXHIBIT B – ENVIRONMENTAL STUDIES

As stated in the Arizona Corporation Commission Rules of Practice and Procedure R14-3-219:

> *Attach any environmental studies which applicant has made or obtained in connection with the proposed site(s) or route(s). If an environmental report has been prepared for any federal agency or if a federal agency has prepared an environmental statement pursuant to Section 102 of the National Environmental Policy Act, a copy shall be included as a part of this exhibit.*

Introduction

The Applicant commissioned environmental studies for the Project, which included an evaluation of land use, biological, visual, cultural, air quality, noise, and recreation resources. The following is an overview of the air quality and groundwater availability studies developed for the Project. The land use, biological, visual, cultural, recreation, and noise resources are discussed in detail in Exhibits A, C, D, E, F, and I, respectively.

Air Quality

The Applicant has applied for an Air Quality Permit Revision from the Pinal County Air Quality Control District (PCAQCD) and has developed an Air Quality Assessment to address the potential impacts of the Project. A summary of the Air Quality Assessment findings follows, and the Air Quality Assessment including the Air Permit Revision Application, modeling report, and construction emission calculations is included as Exhibit B-1.

Baseline Air Quality

The Coolidge Generating Station is an existing electric generating facility that is owned and operated by SRP. The Project will include the installation of 16 aeroderivative GE LM6000PC combustion turbines (CTs) or equivalent natural gas–fired simple-cycle CTs (CT13–CT28) and seven wet surface air coolers (WSACs) (WSAC1–WSAC7) adjacent to the existing Coolidge Generating Station.

The Coolidge Generating Station is in a portion of Pinal County that is designated as being in attainment or unclassifiable for all criteria pollutants except particulate matter with aerodynamic diameter less than 10 micrometers (PM_{10}). The facility is located in the West Pinal PM_{10} nonattainment area, which is classified as serious. The Coolidge Generating Station is currently authorized under a Pinal County Title V Air Permit (Permit V20676.A01), issued on October 1, 2019. SRP submitted a Class I Title V Permit Revision Application to the PCAQCD on August 27, 2021, to authorize the emissions associated with the expanded facility.

Air Quality Impacts During Construction

Construction emissions associated with the Project will result from both on-road and off-road vehicles and equipment, worker commutes, equipment and material deliveries, and fugitive dust. During construction, it is estimated that the worst-case year in terms of emissions could result in 5.88 tons of volatile organic compounds (VOCs), 42.41 tons of CO, 100.59 tons of oxides of nitrogen (NO_X), 3.27 tons of particulate matter (including PM_{10} and $PM_{2.5}$), 3.68 tons of sulfur dioxide (SO_2), and 2,980.38 tons of carbon dioxide (CO_2) on an annual basis. The project will be required to obtain a West Pinal Non-Attainment Area Dust Control Permit. This permit will regulate particulate matter emissions generated due to construction activities. All construction activities will be temporary and transient in nature, with no recurring impacts after construction activities have been completed. Construction emissions compared with emissions from the 2017 Pinal County Emission Inventory are provided in Table 2 of the Coolidge Expansion Air Quality Assessment Technical Memorandum (Exhibit B-1).

Air Quality Impacts During Operation

Emissions due to operational activities will result from the operation of the CTs and WSACs. Estimated operational emissions also include emissions during startup and shutdown. Operations at the Coolidge Generating Station will allow for the plant to emit at a rate that does not exceed the major source threshold for any regulated New Source Review (NSR) pollutant. Annual operational emissions will be restricted to 249.5 tons of VOCs, 249.5 tons of CO, 249.5 tons of NO_X, 249.5 tons of SO_2, and 69.9 tons of particulate matter (including PM_{10} and $PM_{2.5}$). The Class I Title V Air Permit Revision Application is provided in Appendix A of the Coolidge Expansion Air Quality Assessment Technical Memorandum (Exhibit B-1).

Air quality impacts from the Project were assessed by comparing ambient air quality standards and significance levels with the modeled Project ambient air concentrations plus the existing baseline ambient pollutant concentrations in the area of the CEP. The criteria pollutant analysis was conducted to ensure that the Project will not cause or contribute to air pollution in violation of National Ambient Air Quality Standards (NAAQS). Because the Coolidge Generating Station is located in an area of Pinal County that is classified as serious nonattainment for PM_{10}, the modeling analysis demonstrated compliance for both attainment and nonattainment pollutants.

Based on the modeling performed in support of the air permit, the ambient air quality analyses demonstrate the CEP will operate in compliance with the NAAQS. The summary model output is provided in Exhibit B-1.

Greenhouse Gas Emissions

The Project is using the least carbon-intensive fossil fuel source (natural gas). The most prevalent greenhouse gas (GHG) emitted from the Project is CO_2. Maximum emission rates of CO_2 would be limited to a maximum of 120 pounds per million British thermal units (lb/mmBtu) on a 12-month rolling average basis, as required by the New Source Performance Standards (40 Code of Federal Regulations [CFR] Part 60, Subpart TTTT). The maximum emission rate of CO_2 expected to be 116.98 lb/mmBtu.

Conclusion

The air quality assessment demonstrates the Project will operate in compliance with Pinal County, State of Arizona, and federal air quality rules. The Project will not cause or contribute to a violation of the NAAQS, which EPA has established to be protective of human health and the environment.

Water Resources

Introduction

The Project is located in Pinal County within an area designated under Arizona's groundwater regulatory framework as part of the Pinal Active Management Area (Pinal AMA). Established by the 1980 Groundwater Management Code, the Pinal AMA is an area of intense groundwater management within Arizona. The water supply for the project will be 100% derived from the recovery of long-term storage credits (LTSCs) that SRP has acquired within the Pinal AMA. The water associated with the LTSCs will be recovered from wells permitted by the Arizona Department of Water Resources (ADWR) as recovery wells. The hydrologic and regulatory setting of the project, and the effects of the proposed water supply, are summarized below; further detailed information is in the groundwater availability assessment included as Exhibit B-2.

General Hydrologic Setting

Physically, the Eloy groundwater subbasin is characterized by deep alluvial basins with extensive, deep, and productive aquifers. The thickness of alluvial aquifer materials in the subbasin ranges from several hundred feet along the margins of the basin to almost 10,000 feet in the center of the basin. In the vicinity of the Coolidge Expansion project, alluvial sediments are estimated to be about 3,000 feet thick. Well records in the immediate vicinity of the Project confirm that the alluvial sediments near the Project Site are both deep and highly productive.

Groundwater levels near the Project Site follow a typical trend in the Pinal AMA. Groundwater levels in the basin declined steeply until the 1970s before halting and then rising due to reduced groundwater pumping, increased use of Central Arizona Project (CAP) water, and flood recharge from large flood events along the Gila and Santa Cruz Rivers. By 2000, groundwater levels in the vicinity of the project had recovered to 1940s levels, with current depths of roughly 70 to 100 feet below ground surface. In recent years, groundwater levels appear to have started to decline again.

The Pinal AMA generally has groundwater quality that is acceptable for most uses, though there are water quality concerns in the basin including areas of high dissolved solids, nitrates, and fluoride. Drilling at the project site found that overall water quality was acceptable but deteriorated at depths below 400 feet with high levels of dissolved solids, sulfate, and fluoride.

The Pinal AMA also experiences land subsidence due to groundwater pumping. The Eloy subbasin is a known area of subsidence and is actively monitored by the ADWR; recent monitoring indicates subsidence occurring at a rate of approximately 1 centimeter per year. Earth fissures associated with subsidence can also develop, but no earth fissures have been identified within the near vicinity of the Project, with the nearest earth fissures roughly 3 to 4 miles eastward, near the margin of the basin.

Future Projects for the Pinal Active Management Area

The results of recent modeling effort by ADWR for the Pinal AMA were published in 2019, generally raising concerns about future groundwater supplies. The modeling report focused on whether all committed or projected water supplies could physically be obtained from the aquifer and found that, of the roughly 80 million acre-feet projected to be required by the year 2115, only 72 million acre-feet were physically available, suggesting that the Pinal AMA may experience a long-term shortfall of 8 million acre-feet. These shortcomings could be further exacerbated by the ongoing and future drought reductions implemented on the Colorado River, which has directly impacted CAP water delivered to agricultural users in the Pinal AMA.

The critical shortfalls are predicted to occur south of Eloy, roughly 15 to 20 miles from the Project Area. The modeling indicates that groundwater would remain physically available in the Project Area, with likely 500 to 600 feet of saturated aquifer thickness remaining in 2115. In addition, the life expectancy for the Project is significantly shorter than the 100-year modeling time frame.

Effects of the Proposed Water Supply

By recovering LTSCs, the proposed water supply results in a reduction of overall groundwater use in the Pinal AMA. To obtain LTSCs, groundwater is either physically recharged into the aquifer, or surface water is delivered to an entity so that the entity does not have to pump groundwater under an existing groundwater right. In this case, the long-term storage credits were obtained by delivering CAP water to the Hohokam Irrigation District Groundwater Savings Facility. From a water accounting perspective, this mechanism is equivalent to using the CAP water directly at the Project Site rather than using groundwater. In addition, the act of recharging the water through a groundwater savings facility results in a 5% addition to the aquifer that is not subsequently recovered.

Furthermore, the Project would be considered a general industrial user under ADWR's Pinal AMA Fourth Management Plan and would have to comply with the general conservation requirements outlined in the Industrial Conservation Program (§ 6-602), which include avoiding waste by only using the amount of water that is reasonably required for industrial use.

While the groundwater being used is considered to be water recovered from a groundwater savings facility, it must still be physically available at the point of recovery. Based on the latest modeling conducted by ADWR for the Pinal AMA, though groundwater levels are anticipated to decline throughout the basin and at the Project Site, groundwater is anticipated to remain physically available at the immediate Project location through at least 2115. One ramification of falling water levels is that water quality may substantially deteriorate as wells are deepened to access poor-quality groundwater below current well depths of 600 feet. This could require treatment prior to use or could reduce the available cycles before blowdown.

EXHIBIT B-1 – AIR QUALITY ASSESSMENT

This page intentionally left blank.

SWCA
ENVIRONMENTAL CONSULTANTS
Sound Science. Creative Solutions.®

20 East Thomas Road, Suite 1700
Phoenix, Arizona 85012
Tel 602.274.3831 Fax 602.274.3958
www.swca.com

TECHNICAL MEMORANDUM

To: William McClellan, Spence Wilhelm, and Joseph Gardner, Salt River Project

From: Daniel Hampton, Air Quality Specialist, and Brad Sohm, Senior Air Quality Specialist

Date: November 24, 2021

Re: **Coolidge Expansion Air Quality Assessment / SWCA Project No. 00065028-000-PHX**

PURPOSE OF TECHNICAL MEMORANDUM

The purpose of this technical memorandum is to summarize the air quality impacts of the Coolidge Expansion Project (CEP). The following sections describe the existing climate and air quality conditions in the area of the project, the expected construction and operational air emissions, and the potential impacts to air quality that would result from those operational emissions on the ambient air quality in Pinal County, Arizona.

PROJECT INFORMATION

The Coolidge Generating Station is an existing electric generating facility that is owned and operated by Salt River Project (SRP). The facility is in the south-central part of Arizona approximately halfway between Phoenix and Tucson in Pinal County within the City of Coolidge at 859 East Randolph Road. The facility currently consists of 12 simple-cycle combustion turbines (CTs) (General Electric [GE] LM6000PC) and ancillary equipment that produce approximately 575 megawatts (MW) of electrical gross output at ISO conditions at project elevation.

SRP proposes to expand the existing Coolidge Generating Station through the installation of equipment and facilities within the existing power plant boundary (95 acres) and the parcel directly to the south of the existing power plant (approximately 100 acres). The Coolidge Expansion project will include the installation of 16 natural gas–fired simple-cycle CTs (CT13 through CT28). In addition, 7 wet surface air coolers (WSACs) (WSAC1 through WSAC7) are being included as a potential future phase. The Coolidge Expansion project will involve installation of GE LM6000PC CTs or equivalent that will generate approximately 820 MW of additional nameplate electrical output (ISO conditions at sea level).

This project will enable the integration of additional renewable generation while maintaining electric system reliability. SRP expects to add 2,025 MW of solar photovoltaic energy to its renewable portfolio by 2025 to meet its Board approved goal of a 65% reduction in carbon emissions intensity by 2035. Along with increased solar generation comes greater fluctuations in demand for electricity from SRP's power system and a need for fast-ramping generation to meet that increasingly variable demand. Each combustion turbine at the CEP will be capable of rapid starts (within 10 minutes) and quickly changing power output to match variable electricity demand. This flexible operating capability serves reliability needs both when the units are generating and when the plant is offline and not burning fuel.

This memorandum summarizes the air quality impacts that would result from the expansion of the existing Coolidge Generating Station, It describes the existing climate and air quality conditions in the area, the expected air emissions from the existing Coolidge Generating Station and CEP, and the potential impacts that would result from those emissions as predicted by refined air quality modeling.

Additional details are included in the air permit application and supporting refined air quality modeling that has been submitted for the CEP with the Pinal County Air Quality Control District (PCAQCD). Please refer to the air permit application attached as Appendix A and the refined air quality modeling report attached as Appendix B for detailed tables, figures, and supporting information.

EXISTING CLIMATE AND AIR QUALITY

Temperature and Precipitation

The Coolidge Expansion project is located at the southern end of the City of Coolidge in Pinal County, Arizona. The general area is predominantly arid desert characterized by very hot temperatures, large daily temperature range, and sparse precipitation. The mean annual temperature is 70° Fahrenheit (F) with average maximum temperatures ranging from 66 to 106°F and average minimum temperatures from 36 to 76°F. Average annual precipitation is only 9 inches. Most of the precipitation occurs during the winter from December through March and during the monsoonal months of July and August (U.S. Climate Data 2021).

Wind

National Climatic Data Center surface data set (see Appendix B) from Phoenix Sky Harbor International Airport (Weather-Bureau-Army-Navy [WBAN] 23183) in Arizona and upper air data from Tucson (WBAN 23160) in Arizona were used to perform the AERMOD dispersion modeling to support the air permit application for the expansion. Five full years of data between the years of 2014 and 2018 were obtained for the surface and upper air data. A wind rose for the surface station is presented in the attached modeling report (Appendix B). A wind rose is a graphical depiction of the frequency of occurrence of wind direction and wind speed. For the 5-year average, the data shows a predominant wind flow from the east and southeast and a secondary wind flow from the west.

Baseline Air Quality

The Coolidge Generating Station is in a portion of Pinal County that is designated as being in attainment or unclassifiable for all criteria pollutants except particulate matter with aerodynamic diameter less than 10 micrometers (PM_{10}). The facility is located in the West Pinal PM_{10} nonattainment area, which is classified as serious. The most significant air pollutants in Pinal County are PM_{10} and particulate matter with aerodynamic diameter less than 2.5 micrometers ($PM_{2.5}$), which are caused primarily by agricultural activities and naturally occurring windblown dust due to arid conditions.

Ambient background values of air quality data representative of the project area for the years of 2018 and 2020 are included in Table 1 below. These stations were selected as those closest to the CEP for the respective pollutants. This table also presents the relevant National Ambient Air Quality Standards (NAAQS) for each pollutant and averaging period. The locations of the monitoring stations are shown in the modeling report (Appendix B).

Emissions

In Pinal County, air quality is managed by the PCAQCD. Criteria pollutants that are regulated by the PCAQCD include the following:

- Carbon monoxide (CO)
- Nitrogen dioxide (NO_2)
- Sulfur dioxide (SO_2)
- Particulate matter (PM_{10}/$PM_{2.5}$)
- Ozone
- Lead

Table 1 includes the National Ambient Air Quality Standards, the ambient background values for the project area, as well as the monitor locations used to obtain background values.

Table 1. Ambient Background Values (2018–2020)

Pollutant	Average	Background Value* (μg/m³)**	NAAQS (μg/m³)	Design Concentration	Monitor Name	Site ID
NO_2	Annual	15.5 (8.2 ppb)	100 (53 ppb)	Maximum of annual average from 3 years	Tucson	04-019-1028
	1-hour	26.3 (14.1 ppb)	188 (100 ppb)	Recently recommended Arizona Department of Environmental Quality (ADEQ) value	Alamo Lake	Alamo Lake
CO	1-hour	1040 (0.91 ppm)	40,000 (35 ppm)	Highest concentration from past 3 years	Tucson	04-019-1028
	8-hour	812 (0.71 ppm)	10,000 (9 ppm)	Highest concentration from past 3 years		
Ozone	8-hour	137 (0.07 ppm)	137 (0.07 ppm)	Annual fourth highest daily max 8-hour average from 3 years	Casa Grande	04-021-3003
$PM_{2.5}$	Annual	7.19	12	Three-year annual average	Casa Grande	04-021-3003
	24-hour	18.2	35	Average of the 98% 24-hour values over 3 years		
PM_{10}	24-hour	96.0	150	Three-year average (2017–2019) if second highest values	Coolidge	04-021-3004

*Background values for monitoring sites obtained from the EPA's Interactive Map of Air Quality Monitors (EPA 2021) for all pollutants except NO_2. SRP elected to use the ADEQ-recommended 26.3 μg/m³ 1-hour background concentration for Alamo Lake, per the ADEQ Modeling Guidance as updated based on a September 7, 2021, email from PCAQCD to SRP.

**Microgram per cubic meter (μg/m³)

Formation of ozone is related to the complex interaction of air pollutants from regional emission sources and regional meteorological conditions. Thus, performing complex cumulative regional emissions and meteorological modeling for ozone for a single project is extremely difficult and is beyond the scope of the analysis required for the air permit. The ozone precursor emissions were evaluated under the EPA's Modeled Emission Rates for Precursors (MERPs) guidance to demonstrate that the project will not result in quantifiable ozone formation. A discussion of this analysis can be found in section 5.7 of the SRP Modeling Report for Class I Title V Air Permit Application (Appendix B). The inherent nature of the combustion of natural gas in CTs does not result in appreciable lead emissions; therefore, lead emissions from the Coolidge Expansion project will be negligible and well below all regulatory thresholds. In addition, emissions of non-criteria pollutants (e.g., asbestos, mercury, fluorides, and hydrogen sulfide) and greenhouse gasses (CO_2, CO_2e) from the Coolidge Expansion project will also be well below all regulatory thresholds. The CTs use state-of-the-art technology to efficiently burn pipeline quality natural gas with reduced Oxides of Nitrogen (NO_x) and CO emissions. Each CT s equipped with water injection to the combustors to reduce flame temperature and minimize the formation of NO_x. The selective catalytic reduction system further reduces NO_x emissions using a combination of catalysts and injection of 19% aqueous ammonia solution, and an oxidation catalyst is used to reduce CO and VOC emissions.

SO_2 and PM_{10} emissions are controlled through the use of pipeline-quality natural gas and good combustion practices. SO2 emissions as presented in the air permit application were based on sulfur content of 0.25 grains per 100 cubic feet.

CRITERIA POLLUTANTS

Construction Phase Emissions

Construction is expected to occur in phases between the years of 2022 and 2025. These phases are expected to include initial sitework and mobilization, material deliveries, earthwork and underground utilities, foundation work, equipment and mechanical work, electrical work, startup/commissioning, operational testing, and final grading/paving. During these construction phases, different equipment will be required on-site that will result in varying emission rates due to construction activities.

Construction activities result in construction equipment tailpipe emissions, light-duty construction vehicle tailpipe emissions associated with worker commutes, delivery truck emissions from deliveries, storage piles, and haul roads. Construction equipment tailpipe emissions were calculated assuming the equipment will operate during daylight hours throughout the duration of the construction phase in which they will be required. Construction activities are expected to occur 6 days per week. Hours of equipment operation used for emission calculations were based on this preliminary work schedule and were adjusted by load factors, which account for typical operating configurations for different types of equipment during construction activities. Light-duty construction vehicle tailpipe emissions were calculated assuming that workers will have on average an approximately 100-mile round-trip commute. Storage pile and haul road emissions were estimated based on similarly sized projects.

To characterize the maximum impacts that will be experienced as a result of construction activities associated with the Coolidge Expansion project, the year that is expected to result in the maximum emission rates based on preliminary construction plans was used. Based on preliminary plans, it is expected that construction activities will occur 6 days per week year round, with activities occurring during daylight hours.

A summary of construction emissions including both criteria pollutant emissions and greenhouse gasses associated with the worst-case emitting year can be found below in Table 2.

As demonstrated in Table 2, construction emissions represent a small fraction of the emission inventory of Pinal County, with NO_x accounting for the highest percentage at 1.02%. All construction activities will be temporary and transient in nature, with no recurring impacts after construction activities have been completed.

Table 2. Worst-Case Construction Emissions

Source	Emissions (tons/yr)					
	Volatile organic compounds (VOC)*	CO	NO_X	PM/ PM_{10}/ $PM_{2.5}$	SO_2	CO_2†
Construction Vehicles and Equipment‡	5.69	39.67	100.40	3.22	3.66	1501.76
On-Road Vehicle Tailpipe Emissions§	0.41	5.47	0.41	0.06	0.04	94.69
Wind Erosion - Storage Piles¶	-	-	-	0.01	-	-
Haul Roads Vehicle Traffic¶	-	-	-	0.02		-
Total	**6.10**	**45.14**	**100.81**	**3.30**	**3.70**	**1,596.45**
Pinal County 2017 Emission Inventory ¥	9,932.47	51,758.91	9,848.96	28,534.81	111.54	3,448,193.51
Construction Emissions Percent of Pinal County 2017 Emission Inventory	0.06%	0.08%	1.02%	0.01%	3.30%	0.09%

*Hydrocarbons were conservatively assumed to be equal to VOCs.

†CO_2 emission factors for gasoline and diesel On-road vehicles were obtained from the Updated Emission Factors of Air Pollutants from Vehicle Operations in GREETTM Using MOVES (Cai et al 2013).

‡Emission factors for construction vehicles and equipment were obtained from the Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling Compression-Ignition (EPA 2010) and are in units of gram per metric horsepower-hour.

§Emission factors for light-duty construction vehicle tailpipe emissions were obtained from Maricopa Association of Governments (2002:Chapter 5) (MAG 2002) and are in units of grams per mile.

¶Storage pile and haul road emission factors were obtained from the Arizona Department of Environmental Quality (ADEQ 2020). No concrete batch plant will be associated with this project.

¥Data obtained from the EPA's 2017 National Emission Inventory for Pinal County (EPA 2017).

Operational Phase Emissions

Emissions from the combustion turbines will be controlled through the use of clean-burning natural gas, good operating combustion practices, selective catalytic reduction to prevent and reduce NO_x emissions, and an oxidation catalyst to reduce CO and VOC emissions. SO_2 and PM_{10} emissions are controlled through the use of pipeline-quality natural gas and good combustion practices.

SRP used the manufacturer's emissions data to estimate Potential to Emit (PTE) of each regulated New Source Review (NSR) pollutant for the proposed combustion turbines. Estimated emissions also include startup and shutdown emissions that have been combined with normal emissions. Particulate matter, NO_X, CO, and VOC emission rates during startup and shutdown, in terms of pounds per event, were provided by GE. Normal emissions are defined as those occurring between generating loads of 50% to 100%. Maximum emission rates for particulate matter (PM/PM_{10}/$PM_{2.5}$), NO_X, CO, and VOC were obtained from GE for the 100% load condition, at site elevation, for 59°F ambient temperature. The SO_2 emission factor is calculated from the maximum natural gas fuel sulfur content. As a part of the Coolidge Expansion project, SRP is considering installing seven WSACs as a potential future phase that will would result in particulate matter emissions (PM_{10}/$PM_{2.5}$). Particulate matter emissions from the WSACs were estimated using site-specific data, planned operating conditions, and manufacturer specifications.

The project emissions for each regulated NSR pollutant are typically calculated by summing PTE for each of the project-affected emissions units. In this case, restricted PTE for the proposed combustion turbines (startup-shutdown and normal operation) and the WSACs is based on the proposed emission limit for each regulated NSR pollutant. As shown in Table 3, the project emissions (based on the PTE) are below the applicable major source thresholds.

Table 3. Comparison of Emissions for Coolidge Expansion Project with Major Source Thresholds

Pollutant	Potential to Emit for Coolidge Expansion Project (TPY*)	Major Source Thresholds (TPY)
PM	69.9	250
PM_{10}	69.9	70
$PM_{2.5}$	69.9	250
SO_2	249.5	250
NO_X	249.5	250
VOC	249.5	250
CO	249.5	250

*Tons per Year (TPY)

The proposed CEP including emissions from the existing site does not result in a new major source for any regulated NSR pollutant.

Per 40 Code of Federal Regulations (CFR) § 52.21 (b)(49)(iv) (implemented per delegation agreement with the EPA), greenhouse gases (GHGs) are potentially subject to regulation only if the existing stationary source or proposed new stationary source is a major stationary source, as that term is defined at 40 CFR § 52.21 (b)(1), based on its PTE for a regulated NSR pollutant other than GHGs. Because neither the existing Coolidge Generating Station nor the proposed physical change is a major stationary source based on its emissions of non-GHG pollutants, GHGs are not considered subject to regulation for Prevention of Significant Deterioration (PSD). The project is estimated to emit 547,569 tons of the carbon dioxide equivalent (CO_2e) on an annual basis. CO_2e allows for pollutants to be evaluated in terms of their potential to contribute to global warming in terms of CO_2.

Hazardous Air Pollutants

The annual emissions of any HAP for the Coolidge Expansion project will be well below 10 tons per year, and the total HAPs emissions will be well below 25 tons per year, qualifying the Coolidge Expansion project as an area source of HAPs. As an area source of HAPs, the Coolidge Generating Station will not be subject to the federal National Emission Standards for Hazardous Air Pollutants (NESHAP) rules under 40 CFR Part 63 Subpart YYYY, the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. In addition, the sources at this facility are not included in the source categories listed in Chapter 7, Article 2, Table l of the PCAQCD rules.

REGULATORY APPLICABILITY

The Coolidge Generating Station is currently authorized under a Pinal County Title V Air Permit (Permit #V20676.A01), issued on October 1, 2019. SRP submitted a Class I Significant Title V Permit Revision Application to the PCAQCD on August 27, 2021. The following provides a review of the Pinal County, state, and federal air quality regulations applicable to the CEP.

County/State Regulations

Under Arizona Revised Statutes 49-402, ADEQ has original jurisdiction over "major sources in any county that has not received approval from the administrator for new source review under the clean air act and prevention of significant deterioration under the clean air act". Pinal County's nonattainment new source review standards have not been approved by the EPA, although a delegation agreement between ADEQ and Pinal County exists that allows Pinal County to govern major sources within the boundaries of the county. Because Pinal County is relying on this delegation agreement as opposed to their own nonattainment new source performance standards, ADEQ permitting regulations for major sources in Pinal County apply. Because the Coolidge Generating Station will be a major source according to R18-2-218 of the Arizona Administrative Code (AAC), ADEQ's permitting regulations are applicable for the purposes of the Coolidge Expansion project's permitting.

A summary of other applicable county and state regulations can be found below in Table 4.

Table 4. Potentially Applicable County and State Regulations

Citation	Description	Applicability
AAC R18-2-334	Minor New Source Review	The requirements found in this regulation are applicable to a modification that would increase a source's potential to emit equal to or greater than the permitting exemption threshold. The Coolidge Expansion project will exceed these thresholds for all criteria pollutants except SO_2. As a result, reasonably available control technology (RACT) or an ambient air quality assessment is required.
AAC R18-2-334(C)(1)	Reasonably Available Control Technology (RACT)	The application of RACT is required for each emission unit with PTE greater than or equal to 20% of the permitting exemption threshold for a regulated minor NSR pollutant. SRP is proposing RACT for the Coolidge Expansion project irrespective of emission levels when compared to the exemption threshold. For combustion turbines, SRP is proposing to use good combustion practices and clean fuel to control PM_{10}/$PM_{2.5}$, selective catalytic reduction systems to control NO_X, and an oxidation catalyst to control VOCs and CO. For the WASCs, SRP is proposing to use drift eliminators to control PM_{10}/$PM_{2.5}$.
AAC R18-2-334(C)(2)	Ambient Air Quality Assessment	Though not specifically required, SRP has conducted an ambient air quality assessment to confirm that ambient concentrations resulting from the modification combined with the existing concentration of regulated minor NSR pollutants will not interfere with attainment or maintenance of NAAQS.
Pinal County Code § 5-23-1010	Standards of Performance for Stationary Rotating Machinery	Emission limitations for particulate matters are required under this regulation. SRP will be compliant with all applicable emission limits. Additionally, this regulation sets forth opacity limits in which combustion turbines are not permitted to emit smoke for a period greater than 10 consecutive seconds, which exceeds 40% opacity. SRP will abide by these requirements.
Pinal County Code § 4-2-020	Fugitive Dust Countywide	SRP will comply to West Pinal Non-Attainment Area fugitive dust requirements contained within this regulation. Due to SRP being located in the West Pinal Non-Attainment Area for PM_{10}, a West Pinal Non-Attainment Area Dust Control Permit will be required. SRP will comply with all applicable requirements.

Federal Regulations

A description of potentially applicable federal requirements and a brief discussion of their applicability can be found below in Table 5.

Table 5. Potentially Applicable Federal Regulations

Citation	Description	Applicability
40 CFR Part 60, Subpart A	Standards of Performance for Stationary Combustion Turbines	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.
40 CFR Part 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines	This New Source Performance Standard (NSPS) Subpart applies to stationary combustion turbines for which construction, modification, or reconstruction commenced after February 18, 2005. The combustion turbines meet the definition of an affected facility under this standard. As a result, the turbines associated with the Coolidge Expansion project are subject to this NSPS Subpart. SRP will comply with all emission limitations, as well as operating, maintenance, monitoring, and reporting requirements associated with this NSPS Subpart.

Citation	Description	Applicability
40 CFR Part 60, Subpart TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units	This NSPS Subpart applies to carbon dioxide (CO_2) emissions from certain stationary combustion turbines. The Coolidge Expansion project meets the applicability conditions of this regulation and is subject to this NSPS Subpart. SRP will only burn natural gas to comply with this regulation and will comply with any other applicable regulations associated with it. In addition, the combustion turbines will be subject to a nominal CO_2 limitation of 120 pounds per metric million British thermal units (lb/MMBtu) on a 12-month rolling average basis. SRP will comply with this limitation.
40 CFR Part 72 and Code Chapter 3, Article 6	Acid Rain Program	Because the new simple-cycle combustion turbines fire natural gas and produce electricity for sale, these are affected units under the federal Acid Rain Program. SRP will submit an Acid Rain Permit application to the EPA and provide a copy to the PCAQD.

PREDICTED AMBIENT AIR QUALITY IMPACTS

Air quality impacts from the CEP were assessed by comparing ambient air quality standards and significance levels to the modeled project ambient air concentrations plus the existing baseline ambient pollutant concentrations in the area of the Coolidge Expansion project. The analysis evaluated emissions of each criteria pollutant that triggered minor NSR as defined in R18-2-302 of the AAC. The project will trigger minor NSR for all criteria pollutants except lead and SO_2. The criteria pollutant analysis was conducted to ensure that the proposed project will not cause or contribute to air pollution in violation of NAAQS. Since the SRP Coolidge facility is located in an area of Pinal County that is classified as nonattainment for PM_{10}, the modeling analysis addressed the ADEQ's procedures for modeling demonstrations for both attainment and nonattainment pollutants.

The analysis conforms with the modeling procedures outlined in the EPA's Guideline on Air Quality Models (Guideline), the ADEQ's Air Dispersion Modeling Guidelines for Arizona Air Quality Permits, and associated EPA modeling policy and guidance. The modeling analysis also conforms with the modeling protocol submitted to the PCAQCD on August 24, 2021.

The modeling performed included a load screening analysis to determine the operating conditions that result in the highest modeled impacts, a Significant Impact Analysis to calculate the maximum impacts for each pollutant, and a refined NAAQS analysis to determine compliance with the NAAQS.

The dispersion modeling performed in support of the air permit application considers each of the criteria pollutants regulated by PCAQCD, except for ozone and lead. While lead was not included in the modeling, the emissions are predicted to be less than 0.01 tons per year. Photochemical modeling was not performed for this project, though the project's ozone precursor emissions were evaluated under the EPA's Modeled Emission Rates for Precursors (MERPs) guidance to demonstrate that the project will not result in quantifiable ozone formation. The PCAQCD also regulates hazardous air pollutants (HAPs), and an evaluation of these has been included in this analysis.

MODEL RESULTS

Load Analysis Results

The results of the load analysis can be found in Appendix B. The startup load condition was found to cause the highest impacts for all turbines for all pollutant averaging periods. The emissions and stack parameters associated with this load condition were therefore conservatively used in the remainder of the analysis. The startup emissions were not excluded from the significant impact or 1-hour NO_2 NAAQS demonstration.

Significant Impact Analysis Results

The project resulted in significant impacts for PM_{10}, $PM_{2.5}$, and NO_2 (Table 6). Based upon the results of the significant impacts analysis, a cumulative analysis was conducted to assess compliance with the NAAQS.

Table 6. Significant Impact Analysis Results

Pollutant	Avg Period	Maximum Modeled Impact (µg/m³) *	PSD Significant Impact Level (µg/m³)	Maximum Distance to a Significant Impact (km)
NO_2	1-hour	71.3	7.5	25
	Annual	2.25	1.0	1.4
CO	1-hour	116	2,000	NA*
	8-hour	45.8	500	NA*
$PM_{2.5}$	24-hour	4.37	1.2	21.1
	Annual	0.85	0.20	15.9
PM_{10}	24-hour	5.62	5	0.79
SO_2	1-hour	2.40	7.8	NA*
	3-hour	1.49	25	NA*

*Microgram per meter squared (µg/m³)

Note: Pollutant impact is less than the SIL.

NAAQS Analysis Results

Following the determination of significant impacts, an analysis was conducted to assess compliance with the NO_2, PM_{10}, and $PM_{2.5}$ NAAQS. The adjacent Stinger Welding facility was included in the model, and background concentrations were added to the model results to assess compliance. Evaluation of compliance with the 1-hour NO_2 NAAQS was based on the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Evaluation of compliance with the 24-hour $PM_{2.5}$ NAAQS was based on the 98th percentile of the annual distribution of maximum 24-hour concentrations. Compliance with the PM_{10} 24-hour standard was based upon the sixth highest value over the 5-year meteorological period. Annual $PM_{2.5}$ NAAQS compliance was evaluated based upon the average of the 5-year modeled annual concentrations. The results of the NAAQS analysis are presented in Table 7.

Table 7. NAAQS Analysis Results

Pollutant	Averaging Period	Modeled Concentration (µg/m³)*	Background Concentration (µg/m³)	Total Concentration (µg/m³)	Standard (µg/m³)	Total Concentration Percent of NAAQS
NO_2	1-hour	104	26.3	130	188	69.2%
$PM_{2.5}$	Annual	3.70	15.5	19.2	100	19.2%
	24-hour	3.69	18.2	21.9	35	62.6%
PM_{10}	Annual	1.78	7.19	8.97	12	74.8%
	24-hour	41.1	96.0	137	150	91.3%

*Microgram per meter squared (µg/m³)

Based on the modeling results, the total concentrations that includes impacts associated with the project as well as the background concentration were below the NAAQS for all pollutants evaluated. The total concentration percent of NAAQS was lowest for $PM_{2.5}$ under the Annual standard at 19.2%, while PM_{10} under the 24-hour standard was the highest at 91.3%. Summary model output can be found in Appendix B.

GREENHOUSE GAS EMISSIONS

Assuming complete conversion of natural gas (as methane [CH_4]) to CO_2 and water, maximum emission rates of CO_2 would be limited to a maximum of approximately 120 lb/MMBtu on a 12-month rolling average basis. This complies with all applicable regulations provided by 40 CFR §60.5520 and 40 CFR §60.5525. The combustion turbines will comply with this limit, with the maximum emission rate of CO_2 expected to be 116.98 lb/MMBtu, below the 120 lb/MMBtu standard provided by NSPS Subpart TTTT.

As a flexible peaking resource, CEP could displace less responsive, support integration of renewable generation resources, and efficient resources from having to operate to meet peak power demands and/or maintain reserve capacity, thereby potentially reducing net GHG emissions.

CONCLUSION

The air pollutant emissions estimates and ambient air quality analyses presented in this memorandum and the attached air permit application (Appendix A) demonstrate the Coolidge Expansion project will operate in compliance with Pinal County, State of Arizona, and federal air quality rules.

LITERATURE CITED

Arizona Department of Environmental Quality (ADEQ). 2020. General Air Quality Permit for Concrete Batch Plants. Available at: https://static.azdeq.gov/permits/General_CBP_Permit_rev.pdf. Accessed November 4, 2021.

Cai, H., A. Burnham, and M. Wang. 2013. Updated Emission Factors of Air Pollutants from Vehicle Operations in GREETTM Using MOVES. Available at: https://greet.es.anl.gov/publication-vehicles-13. Accessed November 4, 2021.

Maricopa Association of Governments. 2002. 2002 Periodic Ozone Emission Inventory. Available at: https://azmag.gov/portals/0/Documents/ES_2007_8-HourOzonePlan_Appendices-Vol1.pdf. Accessed November 4, 2021.

U.S. Climate Data. 2021. *Climate Coolidge – Arizona*. Available at: https://www.usclimatedata.com/climate/coolidge/arizona/united-states/usca0332. Accessed November 18, 2021.

U.S. Environmental Protection Agency (EPA). 2021. Interactive Map of Air Quality Monitors. Available at: https://www.epa.gov/outdoor-air-quality-data/interactive-map-air-quality-monitors . Accessed November 4, 2021.

———. 2017. 2017 National Emissions Inventory (NEI) Data. Available at: https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data#datas. Accessed October 19, 2021.

———. 2015. Greenhouse Gas and Energy Consumption Rates for On-Road Vehicles: Updates for MOVES 2014. Available at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100NNUQ.pdf. Accessed October 18, 2021.

———. 2010. Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling Compression-Ignition. July.

APPENDIX A

SRP Class I Title V Air Permit Application

Delivering water and power®

Maria Roberts
Director, Desert Basin and Coolidge
DBS100 | P.O. Box 52025
Phoenix, AZ 85072-2025
P: (602) 236-4328
Maria.Roberts@srpnet.com

Mr. Mike Sundblom, Director
Pinal County Air Quality Control District
P.O. Box 987
Florence, AZ 85132

August 27, 2021

Re: Class I Significant Permit Revision Application
Title V Permit Number: V26076.A01

Dear Mr. Sundblom,

Salt River Project Agricultural Improvement and Power District (SRP) is submitting the attached Class I significant permit revision application for Title V air quality permit (Permit Number V26076.A01) for the Coolidge Generating Station. With this revision, SRP is proposing to install 16 natural gas-fired simple cycle combustion turbines at Coolidge.

If you have any questions regarding the enclosed protocol, please feel free to contact Kristin Watt at (602) 236-5448.

Sincerely,

Maria Roberts

Maria Roberts
Director, Desert Basin and Coolidge Generating Stations

TITLE V / CLASS I PERMIT REVISION APPLICATION
COMBUSTION TURBINES PROJECT AT
COOLIDGE GENERATING STATION
COOLIDGE, ARIZONA
TITLE V / CLASS I PERMIT NUMBER: V20676.A01

Submitted to:

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

Submitted by:

Salt River Project Agricultural Improvement and Power District
1500 N. Mill Ave.P.O. Box 52025 PAB359
Tempe, AZ 85281

August 2021

Table of Contents

1.0 INTRODUCTION

Coolidge Generating Station ("COE") is an existing electric generating facility that is owned and operated by the Salt River Project Agricultural Improvement and Power District ("SRP"). The facility is in the south-central part of Arizona approximately half-way between Phoenix and Tucson in the City of Coolidge at 859 East Randolph Road. The facility consists of twelve (12) simple cycle combustion turbines ("CT") (General Electric ("GE") LM6000PC) and ancillary equipment that produce approximately 575 MW of electricity (SIC code 4911). The facility is operating under the Class I Permit Number V20676.A01 issued on June 29, 2019.

SRP is proposing a project to install sixteen (16) natural gas-fired simple cycle combustion turbines ("CT13" through "CT28") and seven (7) wet surface air coolers ("WSAC1" through "WSAC7") (hereinafter "CT Project" or "Project") at COE. The Project will involve installation of GE LM6000PC combustion turbines or equivalent that will generate approximately 820 MW (combined).[1] In addition, SRP is also requesting changes to some of the permit terms and conditions for the existing units.

COE is in a portion of Pinal County that is designated as attainment or unclassifiable for all criteria pollutants except particulate matter with aerodynamic diameter less than 10 micrometers (PM10). The facility is located in the West Pinal PM10 nonattainment area, which is classified as serious.[2] This facility is currently a "major source" under Arizona Administrative Code (A.A.C.) R18-2-401 for the nonattainment new source review ("NNSR") program, with respect to PM10 only. For the prevention of significant deterioration ("PSD") program, the facility is an existing minor source limited to less than 250 tons per year ("TPY") potential to emit ("PTE") of each regulated NSR pollutant under its Class I Permit. [3] In this application, SRP is first proposing to limit the existing

---

[1] GE LM6000PC or its equivalent each with approximately 51.1 MW gross generation capacity at 59 °F ambient temperature at full load at sea level.

[2] 40 CFR § 81.303.

[3] NSR – New Source Review.

CTs to less than 70 TPY of PM10, as a synthetic minor limit for PM10. As a result, the source at which construction is proposed is a minor source for all regulated NSR pollutants. Second, in accordance with R18-2-401(13)(c), SRP is proposing to limit the emissions of each regulated NSR pollutant below the applicable 'major source' threshold for the proposed CT Project. Therefore, the proposed Project will not be subject to review under the NNSR and PSD programs. As explained in subsection 5.1.3, the proposed CT Project requires a Class I Permit significant permit revision under Pinal County Code § 3-2-195. SRP is submitting this permit application to Pinal County Air Quality Control District ("PCAQCD") that addresses the requirements for an application for a Class I Permit revision. Also addressed are New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") requirements that are potentially applicable to the Project.

1.1 Application Organization

The remaining sections of the application are organized as follows:

- **Section 2.0 – Site Information** presents general facility information including name, address, SIC code, permit number, and contact information.
- **Section 3.0 – Project Description** provides a description of the proposed Project scope.
- **Section 4.0 – Project Emissions** presents the methodology used to estimate the Project emissions as well as a summary of results.
- **Section 5.0 – Regulatory Requirements** presents an analysis of air quality permitting requirements and the applicability of federal and Pinal County Code to the Project.
- **Section 6.0 – Permit Terms and Conditions** presents proposed permit terms and conditions to keep the Project below exemption thresholds.
- **Appendix A –Application Forms** contains completed application forms for the Project specific information.
- **Appendix B – Emissions Calculations** contains project emissions calculations.

2.0 SITE IDENTIFYING INFORMATION

Company Name:	Salt River Project Agricultural Improvement and Power District
Company Address:	P.O. Box 52025 PAB359, Phoenix, AZ 85072-2025
Facility Name:	Coolidge Generating Station
Facility Address:	859 East Randolph Road, Coolidge, AZ 85128
Responsible Official:	Maria Roberts, Director, Coolidge Generating Station
Responsible Official Phone:	(602) 236-4328
SIC:	4911 (Electric Services)
Permitting Contact:	Zachary Harbin, Senior Environmental Compliance Engineer (602) 236-5779 zachary.harbin@srpnet.com
Facility Contact:	David Lickteig, Senior Environmental Scientist/Engineer (602) 236-7248 david.lickteig@srpnet.com
Site Class I Permit Number:	V20676.A01
Site Part 70 Permit Date:	June 29, 2019

Figure 2-1 is the aerial map of the area showing the site location for COE.

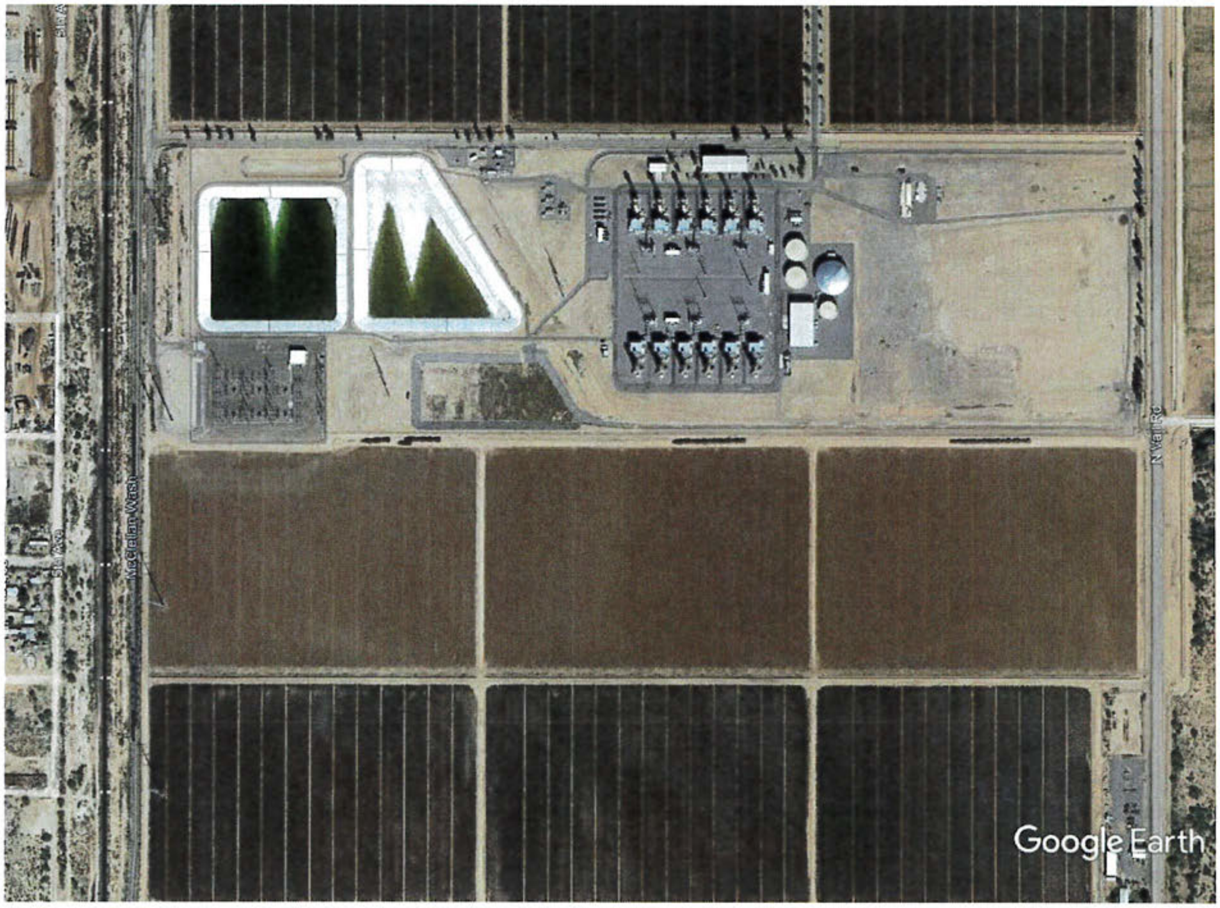


Figure 2-1. Aerial Map of COE Site

3.0 PROJECT DESCRIPTION

SRP is proposing to install ~820 MW generating capacity to provide reliable, immediately dispatchable peaking power. The proposed CT Project involves installation of sixteen (16) natural gas-fired simple cycle combustion turbines to serve peak capacity and allow the integration of renewable resources to the grid. SRP is anticipating the new units to be aero-derivative GE LM6000PC or its equivalent each with approximately 51.1MW gross generation capacity that will generally serve the peak electricity demand.[4]

The proposed CTs will be equipped with inlet chillers to maintain the turbine performance at high ambient temperature. In addition, SRP is proposing to install inlet chillers on the existing CTs. Up to seven (7) wet surface air cooler ("WSAC") units—three to serve the inlet chillers for the existing CTs and four to serve the inlet chillers for the new CTs—will also be installed as part of the project to provide the cooling water for inlet chilling.

3.1 Aeroderivative CTs - General Electric LM6000PC

The aeroderivative GE Model LM6000PC simple cycle combustion turbine will be coupled to an electric generator to produce electric power for supply to the grid. A combustion turbine is an internal combustion system which uses inlet air as a working fluid to produce mechanical power. This combustion turbine technology comprises an air inlet system, two compressor sections, a combustion section, and a turbine section. As the name implies, aeroderivative combustion turbines are based on turbine designs used in the aviation industry. By design this turbine technology is capable of starting and ramping-up to full capacity within 10 minutes. Aeroderivative turbine models are generally specified for use where fast start capability, power demand matching, and relatively lower power outputs are the primary objectives. The air inlet system includes an inlet air heater, inlet air cooler, air filters, and noise silencer that supplies air to the multistage axial compressor. This turbine technology is lightweight, compact, and

[4] MW rating provided by the Manufacturer at sea level at full load.

operates at high compression ratios compared to other turbine technologies. Aeroderivative turbines like those specified for the proposed CT Project operate at a very high compression ratio (typically in excess of 30). The pressure ratio is the ratio of air pressure at the discharge compared to the inlet of the compressor section.

During operation, ambient air is drawn into the compressor section. Once the air is compressed it is heated by the combustion of fuel gas 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 3-1 presents a diagram for the LM6000PC CT. The CT are equipped with inlet air filters which remove dust and particulate matter from the inlet air. During hot weather, the filtered air will also be cooled by passing through an inlet air chiller or 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 a glycol and water solution as the working fluid that is heated by induction heaters. The filtered air is drawn into the low-pressure compressor section where the air is compressed. The CTs are also equipped with spray intercooling, (SPRINT), which allows for demineralized water to be atomized within the low-pressure compressor. The resulting increase in mass flow allows for higher power output in high ambient conditions. The low-pressure compressor section features fixed inlet guide vanes. The high-pressure section of the compressor uses independently controlled variable stator vanes to optimize air flow to the combustion section. Incorporation of these advanced airflow and cooling technologies help the proposed turbines have lower emission rates, increased fuel efficiency, and minimized unburned hydrocarbon emissions. Water is also injected into the combustion section of the turbine which reduces flame temperatures and thermal formation of nitrogen oxides (NO_X).

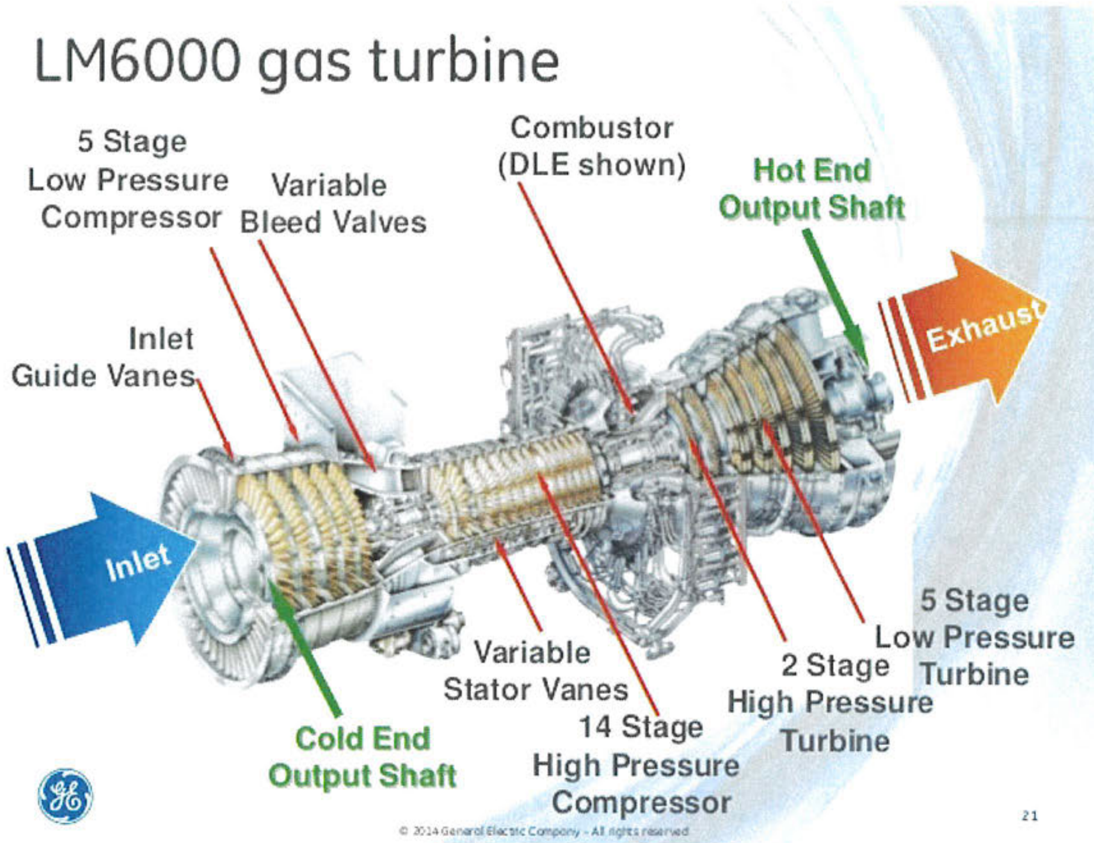


Figure 3-1. Diagram of a GE Model LM6000 Simple Cycle Combustion turbine (*from GE Company*)

The general specifications for these CTs provided by the manufacturer are summarized in Table 3-1. Note that the specifications in this table are for new turbines which have not undergone any performance degradation due to normal operation, and also do not account for efficiency reductions due to post combustion emission control systems.

Table 3-1. General Specifications for the GE LM6000PC Simple Cycle CTs

Parameter	Value
GE Model	LM6000PC (60 Hz)
Number of Units	16
ISO Base Output Power (Gross) at Sea Level	(51.1 MW each)820 MW
Heat Rate ISO Full Load (Net)	8,651 Btu/kW-hr (LHV)
Heat Input Rate Full Load (59 °F ambient)	490 MMBtu/hour (HHV)

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:

- Inlet air filters
- Spray Intercooling (SPRINT)
- Inlet chillier or evaporative cooling
- Anti-icing system
- Metal acoustical enclosure to reduce sound
- Duplex shell and tube lube oil coolers for the combustion turbine and generator
- Annular standard combustor combustion system
- Water injection system for NOx control
- Compressor intercooler system
- Fire detection and protection system
- Hydraulic starting system
- Compressor variable bleed valve vent to prevent compressor surge in off-design operation.

3.2 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 high-temperature SCR systems for the control of NO_X emissions.

3.3 Wet Surface Air Coolers

The CT Project will include seven (7) wet surface air coolers ("WSAC") to provide cooling water for the inlet chillers for the existing and new CTs. Heated water/fluid from the inlet chillers to be cooled flows through tube bundles in a closed loop system. Water from the WSAC basin is sprayed downward over the tube surfaces. At the same time, fans induce air flow over the bundles in a co-current direction. The saturated air stream leaving the tube bundles then makes two 90-degree turns into the WSAC fan plenum removing any remaining large water droplets. This type of design allows for minimal water loss due to evaporation when compared to a traditional cooling tower. The project design involves routing water flow from up to four CTs to each of the WSAC for cooling. The maximum recirculation rate (spray rate) for each WSAC is 10,600 gallons per minute (gpm). Each WSAC will be equipped with high-efficiency drift eliminators to minimize the particulate matter emissions from the process from water droplets escaping the atmosphere.

4.0 SITE AND PROJECT EMISSIONS

This section presents a summary of the emission rates of regulated NSR pollutants for the existing operations and presents information about the project emissions increases of regulated NSR pollutants.

4.1 Regulated NSR Pollutants

The regulated NSR pollutants for PSD applicability purposes are particulate matter (PM), particulate matter equal to or less than an aerodynamic diameter of nominally 2.5 µm (PM2.5), NO_X as nitrogen dioxide (NO_2), sulfur dioxide (SO_2), NO_X and VOC as precursors for ozone, and CO.[5] The NNSR program covers particulate matter equal to or less than an aerodynamic diameter of nominally 10 µm (PM10).

4.2 Existing Operations at COE

Condition 4.C of the Class I permit limits emissions from the following existing units to 245 tons per 12-month period for CO, NO_X, VOC, PM10/PM2.5 and SO_2 (separately for each pollutant).

(a) Twelve (12) combustion turbines for normal operation as well as startup and shutdown duration.
(b) One diesel fuel-fired fire pump engine.

As previously noted, in a recent rulemaking, the U.S. EPA classified the West Pinal PM10 nonattainment area as 'serious.'[6] Therefore, as explained in the Major New Source Review Applicability Subsection 5.1.4, under the NNSR program, the 70 tpy

---

[5] Per 40 CFR § 52.21(b)(49)(iv) (implemented per delegation agreement with EPA), greenhouse gases (GHGs) are potentially subject to regulation only if the existing stationary source or proposed new stationary source is a major stationary source, as that term is defined at 40 CFR § 52.21(b)(1), based on its PTE for a regulated NSR pollutant other than GHGs. Because neither the existing COE nor the proposed physical change is a major stationary source based on its emissions of non-GHG pollutants, GHGs are not considered subject to regulation for PSD.

[6] 85 Fed. Reg. 37756, June 24, 2020.

major source threshold applies for PM10. As further explained in the same subsection, as part of this application, SRP is requesting a more stringent PM10 emission limit from the existing operations at COE to less than 70 tpy (reduced from 245 tpy). Historical operations of the existing CTs has resulted in actual annual emissions that are far less than 70 tpy. In addition, historical performance testing for the existing CTs has shown PM10 emission rate below 0.005 lb/MMBtu. This emission rate is well below the PM10 emission factor of 0.01 lb/MMBtu used in the initial permitting of these units. Therefore, based on the available operational information for the existing CTs, the proposed PM10 emission limitation of less than 70 tpy is easily achievable and appropriate for this operation to maintain the minor source status of the existing operations at COE for NNSR program. Even though SRP is proposing to install inlet chilling for the existing CTs, no changes are proposed to the existing and proposed emission limitations for regulated NSR pollutants that are taken to avoid NNSR and PSD applicability for the existing emissions units at the COE site.

4.3 Proposed CT Project at COE

As previously noted, the proposed CT Project will be constructed at an existing stationary source that is not a 'major source' under R18-2-401(13): the emissions of all regulated NSR pollutants subject to PSD from the existing emissions units are each limited to 245 tpy and PM10 emissions, which are subject to nonattainment NSR, will be limited to less than 70 tpy as a result of this permit request. Therefore, the proposed CT Project is a physical change at an existing stationary source that is not a major source per R18-2-401(13)(a) or (b). For purposes of determining 'major source' applicability under R18-2-401(13)(c) for PSD and NNSR, the PTE of each regulated NSR pollutant from the proposed CT Project is quantified. The major source determination is made by comparing PTE of each regulated NSR pollutant from the proposed physical change to the applicable 'major source' thresholds under R18-2-401(13)(a) and (b) (depending on the attainment status for a particular criteria pollutant). A summary of the PTE calculations for the equipment proposed under the CT Project is presented below. Detailed emissions calculations are included in Appendix B of this application.

4.3.1 Potential to Emit of the Proposed Combustion Turbines

In accordance with definition of potential to emit under R18-2-101(110), SRP used the manufacturer's emissions data to estimate PTE of each regulated NSR pollutant for the proposed CTs.[7] For this purpose, we are using the CTs' emissions information for the site conditions at 55 °F ambient temperature, which corresponds to the worst-case emission rates of regulated NSR pollutants. Table 4-1 presents the design parameters for the proposed GE LM6000PC CTs.

Table 4-1. Design Parameters for the Proposed GE LM6000PC

Parameter	Value	Units
Number of units	16	
Maximum heat input (59 °F, 13.97 PSI, full load)	490	MMBtu/hour (HHV)
Number of startups per CT	730	events/year/CT
Startup duration	30	Minutes
Shutdown duration	9	Minutes

The air pollution control systems—SCR and oxidation catalysts—are not operational during the startup and shutdown of the aeroderivative combustion turbines. Water injection is used to reduce NO_X emissions from these CTs. The earlier that water injection can be initiated during the startup process, the lower NOx emissions will be during startup. However, if injection is initiated at very low loads, it can impact flame stability and combustion dynamics, and it may increase CO emissions. These concerns must be carefully balanced when determining when to initiate water injection. SCR and oxidation catalyst systems are not fully functional during periods of startup and shutdown because the exhaust gas temperatures are too low for these systems to function as designed. During a startup, as the CT achieves minimum emissions compliance load ("MECL"), the CT emissions controls reduce the stack emission rates of NOx and CO below the emission rates for normal operation.

[7] SO_2 emission rate is calculated based on the maximum fuel sulfur content.

For simple cycle CTs, the time required for startup is much shorter than CTs used in combined cycle applications.[8] The aeroderivative 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 30 minutes and for purposes of this permit application, emissions calculations have been conducted using the full 30 minutes for a startup cycle. 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 9 minutes. Therefore, the normal duration for a startup and a shutdown cycle is 39 minutes. The startup and shutdown annual emissions are calculated using the maximum number of startups and shutdowns cycles per year per aeroderivative CT. Particulate matter, NO_X, CO, and VOC emission rates during startup and shutdown, in terms of pounds per event, were provided by GE.

Maximum emission rates for particulate matter (PM/PM10/PM2.5), NO_X, CO, and VOC were obtained from GE for the 100% load condition, at site elevation, for 59 °F ambient temperature. SO_2 emission factor is calculated from the maximum natural gas fuel sulfur content. Calculations summary for other pollutants such as lead, greenhouse gases etc. are not included here as these are not critical from air permitting applicability standpoint.

Emissions rates specifications for the regulated NSR pollutants for the proposed aeroderivative simple cycle combustion turbines are summarized in Table 4-2.

---

[8] In Table 4-3, the startup and shutdown emissions are detailed by event and the maximum annual emissions are also shown. Heating up the heat recovery steam generator (HRSG)and associated steam turbine system in a combined cycle setup requires a slow ramp up of the CT resulting in longer startup and shutdown duration versus a simple cycle CT without a HRSG.

Table 4-2. Emissions Specifications for CTs (GE LM6000PC)

Pollutant	Max Emission Rate for One CT	
	Normal Operation (lbs./hour)	lbs./SU-SD event
PM*	4.4	5.1
PM10	4.4	5.1
PM2.5	4.4	5.1
SO_2	0.5	0.33
NO_X	4.4	18.2
VOC	4.3	2.7
CO	7.6	32.3
* PM conservatively includes both filterable and condensable fractions.		

Table 4-3 below presents the restricted PTE for the proposed CT Project. Restricted PTE is based on the requested limit to keep project emissions below the major source thresholds under R18-2-401(13)(a) and (b).

Table 4-3. PTE for CTs

Regulated NSR Pollutant	Restricted Potential to Emit for One CT (TPY)	Restricted Potential to Emit for Sixteen CTs (TPY)
PM	4.0	63.3
PM10	4.0	63.3
PM2.5	4.0	63.3
SO_2	0.3	4.7
NO_X	8.8	141.5
VOC	3.1	50.2
CO	15.6	249.4

4.3.2 Potential to Emit of the Wet Surface Air Coolers

In a WSAC a small amount of the water is entrained in the induced air flow in the form of liquid phase droplets or mist. Demisters are used at the outlet of the exhaust fans to reduce the amount of water droplets entrained in the air. The water droplets that pass through the demisters and are emitted to the atmosphere are called drift loss. When these droplets evaporate, the dissolved solids in the droplet become particulate matter. Therefore, WSAC are sources of PM, PM10, and PM2.5 emissions.

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

$$E = k * Q * 60 \left[\frac{min}{hour}\right] * 8.345 \left[\frac{lb\ H2O}{gallon}\right] * \left[\frac{CTDS}{10^6}\right] * \left[\frac{DL}{100}\right]$$

Where, E = Particulate matter emissions, pounds per hour
Q = Circulating water flow rate, gallons per minute
CTDS = Circulating water total dissolved solids, ppm
DL = Drift loss, %
k = Particle size multiplier for PM10 and PM2.5[9]

The specifications for the proposed WSAC units are summarized in Table 4-4.

Table 4-4. Specifications for WSAC for Frame CTGs

Parameter	Value
Number of WSAC Units	7
Number of Fans	6
Maximum Circulating Water Flow (gpm) per WSAC Unit	10,600
Maximum Total Dissolved Solids (ppm)	5,000
Hours of Operation (same as CTs)	1,000
Design Drift Loss (%)	0.0005%

Table 4-5 presents the calculated PM, PM10, and PM2.5 restricted PTE for the WSAC, using the particle size multipliers developed from the CTDS value.

[9] PM10 and PM2.5 particle size multiplier from "*Calculating Realistic PM10 Emissions from Cooling Towers*"; Reisman & Frisbie (uses EPRI wet droplet size distribution), Environmental Progress, 2002.

Table 4-5. Restricted PTE for Seven WSAC Units

Pollutant	k Particle Size Multiplier	PTE	
		lb/hour	ton/year
PM	1.000	0.93	0.46
PM10	0.30	0.28	0.14
PM2.5	0.002	0.002	0.001

4.3.3 Project Emissions for Proposed CT Project

The project emissions for each regulated NSR pollutant are typically calculated by summing PTE for each of the Project-affected emissions units. In this case, restricted PTE for the proposed CTs (startup – shutdown and normal operation) and the WSAC is based on the proposed emission limit for each regulated NSR pollutant. As shown in Table 4-6 the project emissions increases (based on the restricted PTE) are below the applicable 'major source' thresholds specified under R18-2-401(13)(a) and (b) for all regulated NSR pollutants.

Table 4-6. Comparison of Project Emissions for CT Project with Major Source Thresholds

Pollutant	Restricted Potential to Emit for the CT Project (TPY)	R18-2-401(13)(a) and (b) Major Source Thresholds (TPY)
PM	69.9	250
PM10	69.9	70
PM2.5	69.9	250
SO_2	12.2	250
NO_X	249.5	250
VOC	249.5	250
CO	249.5	250

The proposed CT Project does not result in a new major source for any regulated NSR pollutant. Therefore, the requirements of R18-2-402(C) for a major source are not applicable to the proposed Project.

5.0 REGULATORY COMPLIANCE ANALYSIS

This section of the application documents SRP's review of Pinal County, State, and federal air quality regulations applicable or potentially applicable to the CT Project. Applicability conclusions are summarized by regulatory program. For each applicable regulation, specific requirements are documented.

5.1 County/State Regulations

This analysis is based on the latest version of Pinal County's Air Pollution Control Regulations available from the County's website and applicable A.A.C. Title 18 rules available from the website for Arizona Secretary of State's office. Under the Arizona Revised Statutes ("A.R.S.") 49-402, Arizona Department of Environmental Quality ("ADEQ") has original jurisdiction over "[m]ajor sources in any county that has not received approval from the administrator for new source review under the clean air act and prevention of significant deterioration under the clean air act." As noted in the December 13, 2016 ADEQ submittal, Pinal County nonattainment new source review rules are not approved in the state implementation plan for the area.[10] Specifically, ADEQ permitting regulations apply for major sources that are in Pinal County under a delegation agreement (see excerpt below).

> *The nonattainment area preconstruction permit program for the portions of the Moderate ozone nonattainment area located in Pinal County is administered by the Pinal County Air Quality Control District under a delegation agreement with the Arizona Department of Environmental Quality. Pinal County does not have an approved nonattainment new source review program. Under A.R.S. Section 49-402 A.1., the Arizona Department of Environmental Quality therefore has original jurisdiction over major sources located in the County, and the Department's permitting rules, rather than Pinal County's, apply to these sources.* [pp 4-47]

---

[10] See, "*MAG 2017 Eight-Hour Ozone Moderate Area Plan for the Maricopa Nonattainment Area,*" Maricopa Association of Governments, December 2016, available at: https://static.azdeq.gov/aqd/2017_maricopa_o3_mod_pln.pdf (last accessed March 24, 2021).

In the preamble to the 2021 rulemaking for Air Plan Approval, Stationary Sources, New Source Review Updates, the U.S. EPA confirmed the ADEQ jurisdiction and delegation for major sources in Pinal County.[11]

> *The ADEQ has permitting jurisdiction for the following stationary source categories in all areas of Arizona: Smelting of metal ores, coal-fired electric generating stations, petroleum refineries, Portland cement plants, and portable sources. The ADEQ also has permitting jurisdiction for major and minor sources in the following counties: Apache, Cochise, Coconino, Gila, Graham, Greenlee, La Paz, Mohave, Navajo, Santa Cruz, Yavapai, and Yuma. Finally, the ADEQ has permitting jurisdiction over major sources in Pinal County (currently delegated to Pinal County Air Quality Control District) and any source in Maricopa, Pima, or Pinal County for which the ADEQ asserts jurisdiction.*

Coolidge Generating Station will be a major source as defined in R18-2-401(13) after the CT Project permitting. Therefore, ADEQ's air permitting regulations are applicable for purposes of the proposed CT Project.[12]

5.1.1 R18-2-334 Minor New Source Review

In accordance with R18-2-334(A)(3), minor new source review permitting requirements are applicable to a modification that would increase the source's potential to emit equal to or greater than the permitting exemption threshold. A comparison of the regulated minor NSR pollutant PTE for the proposed CT project with the Permitting Exemption Thresholds under R18-2-101(101) is provided in Table 5-1.

---

[11] 86 Fed. Reg. 31927, June 16, 2021.

[12] It is worth noting that the current Pinal County's Air Pollution Control Regulations for major sources under both PSD and NNSR are identical to ADEQ's regulations, but EPA has not yet approved these Pinal County regulations into the SIP. Pinal County has no SIP-approved NNSR regulations. Pinal County has a previously-SIP-approved PSD program, but this program is inapplicable here because, as discussed above, major sources in Pinal County are subject to ADEQ original jurisdiction.

Table 5-1. Comparison of Project Emissions for CT Project with Permitting Exemption Thresholds

Pollutant	Restricted Potential to Emit for the CT Project (TPY)	R18-2-101(101) Permitting Exemption Thresholds (TPY)	Whether above the exemption threshold?
PM10	69.9	7.5	Yes
PM2.5	69.9	5	Yes
SO_2	12.2	20	No
NO_X	249.5	20	Yes
VOC	249.5	20	Yes
CO	249.5	50	Yes

The restricted PTE of the proposed CT Project exceeds the permitting exemption thresholds for PM10, PM2.5, NO_X, VOC, and CO. Therefore, the minor new source review permitting requirements under this regulation are applicable to the proposed CT Project. Specifically, R18-2-334(C) requires a Class I permit revision involving a minor NSR modification to meet either reasonably available control technology ("RACT") under R18-2-334(C)(1) or an ambient air quality assessment under R18-2-334(C)(2). This application for a Class I permit revision constitutes SRP's application for an approval under this provision.

5.1.1.1 R18-2-334(C)(1) Reasonably Available Control Technology

R18-2-334(C)(1)(b) requires application of RACT as determined by the PCAQCD/ADEQ for each emissions unit with PTE greater than or equal to 20% of the permitting exemption threshold for a regulated minor NSR pollutant. In this case, SRP is conservatively proposing RACT for the CT project as shown in Table 5-2, irrespective of the level of emissions of regulated minor NSR pollutants from the specific project affected emissions units. We reviewed information in the U.S. EPA's RBLC database to determine RACT proposals for the proposed emission units.

Table 5-2. RACT Proposals for Regulated Minor NSR Pollutants for CT Project

Emission Unit	Pollutant	Proposed RACT
Simple Cycle Combustion Turbines	PM10/PM2.5	Good combustion practices Use of clean fuel (natural gas)
	NO_X	Selective catalytic reduction system
	VOC/CO	Oxidation catalyst
Wet Surface Air Coolers	PM10/PM2.5	Drift eliminators

5.1.1.2 R18-2-334(C)(2) Ambient Air Quality Assessment

Even though not specifically required at this time, in accordance with R18-2-334(C)(2)(b), SRP conducted an ambient air quality assessment for the proposed CT Project. A detailed ambient air quality assessment report will be submitted in the near future upon incorporation of any comments/changes from the review of the modeling protocol. This assessment confirms that that the ambient concentrations resulting from the modification combined with the existing concentration of regulated Minor NSR pollutants will not interfere with attainment or maintenance of a national ambient air quality standard ("NAAQS").

5.1.2 R18-2 Article 4 Permit Requirements for New Major Sources and Major Modifications to Existing Major Sources

R18-2-401 through -412 are the NNSR and PSD provisions applicable to new major stationary sources or projects that are major modifications for regulated NSR pollutants. As previously noted, COE is located in the 'West Pinal PM10 Nonattainment Area' as shown in Figure 3-1 below. The area is 'serious' nonattainment for PM10 and attainment or unclassifiable for all other criteria pollutants. The PTE of all regulated NSR pollutants other than PM10 for the existing emissions units at the COE site is limited by the permit below the 250 tpy threshold applicable under R18-2-401(13)(b). In this application, SRP is requesting a permit limit for the PM10 PTE of existing operations below the 70 tons per year threshold applicable under R18-2-401(13)(a). Therefore, COE is an existing stationary source, that is not a 'major source' as defined in the NNSR and PSD regulations at R18-2-401(13).

Changes to existing stationary sources that are not major sources are addressed as follows:

> *"A major source includes a physical change that would occur at a stationary source, not otherwise qualifying under subsection [R18-2-401](13)(a) or (b) as a major source, if the change would constitute a major source by itself."* [R18-2-401(13)(c)]

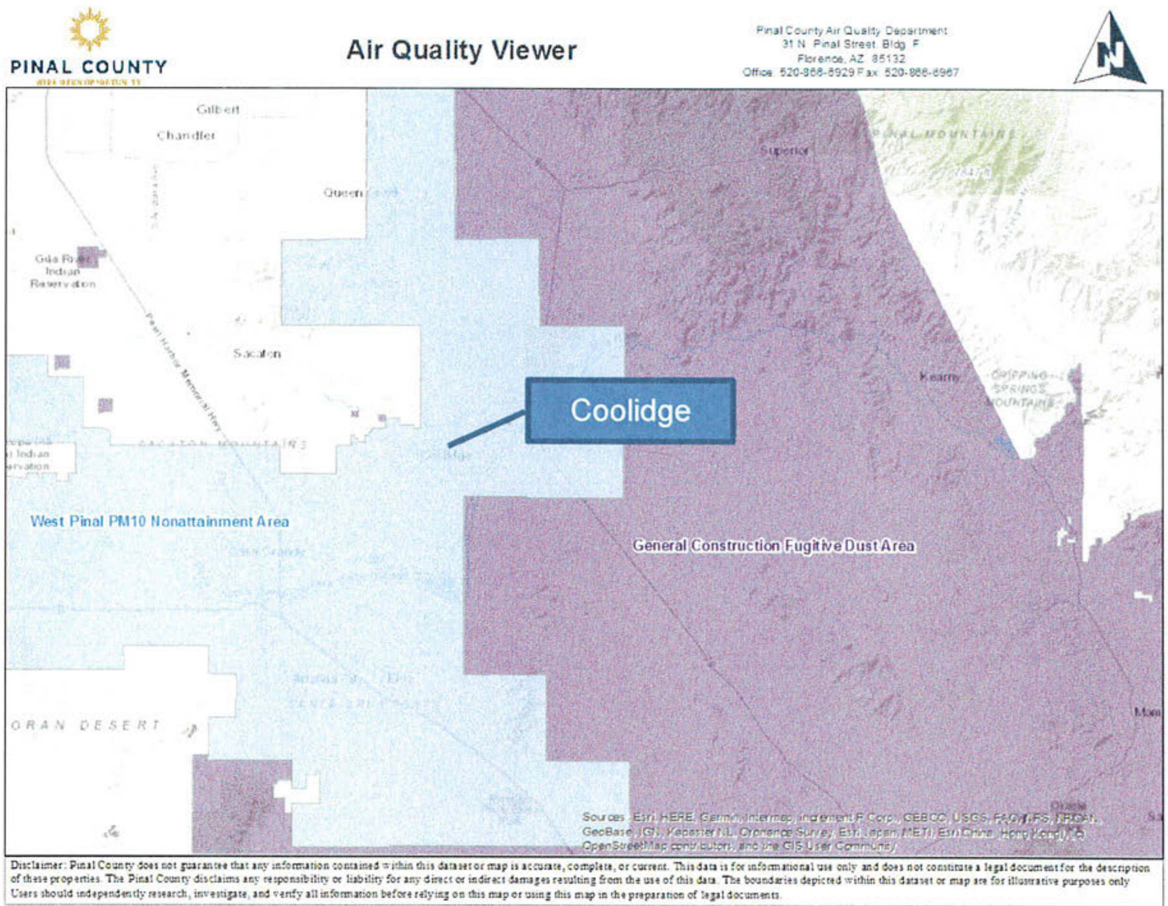


Figure 3-1. Coolidge Generating Station Location in West Pinal PM10 Nonattainment Area

In accordance with R18-2-401(13)(c), SRP evaluated PTE for PM, PM10, PM2.5, SO_2, NO_X, CO, and VOC associated with the proposed CT Project against the major source thresholds under R18-2-401(13)(a) and (b). The results of this analysis are summarized in Table 4-6 and detailed calculations are provided in Appendix B. The proposed CT Project emissions for all regulated NSR pollutants are less than the 'major source' thresholds in R18-2-401(13)(a) and (b). Thus, the proposed CT Project does not constitute a major source and is not subject to the NNSR or PSD permitting requirements.

5.1.3 Code § 3-2-195 Significant Permit Revision to a Class I Permit

In accordance with Pinal County Code § 3-2-190 and R18-2-319(A)(4), any changes that require establishment of a permit term or condition to avoid an otherwise applicable requirement are not considered a minor permit revision and are subject to significant permit revision requirements under Code § 3-2-195 and R18-2-320(A). As explained in Subsection 4.3.3, SRP is requesting enforceable emission limitations to keep the CT Project increase below the major source thresholds under R18-2-401(13)(a) and (b). Therefore, a significant permit revision to the Class I Permit per Code § 3-2-195 and R18-2-320 is required for the proposed CT Project. This document and its attachments fulfill the requirements for an application for a significant permit revision under Code § 3-2-195 and R18-2-320.

In addition to the CT Project, SRP is also proposing additional changes to the existing permit terms and conditions under the Class I Permit V20676.A01 pertaining to the existing emissions units at the COE site. However, these changes do not change the air permitting applicability outlined here. Section 6.0 presents SRP's proposed changes to the existing permit terms and conditions.

5.1.4 Code § 3-7-590 Class I Permit Fees

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

5.1.5 Code § 5-23-1010 Standards of Performance for Stationary Rotating Machinery

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

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

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

In addition, the proposed CTs are not allowed to emit smoke for any period greater than 10 consecutive seconds which exceeds 40% opacity. Visible emissions when starting cold equipment shall be exempt from this requirement for the first 10 minutes.

The proposed CTs will only use natural gas and will follow these standards.

5.1.6 Other County Requirements

There are no changes to the other applicable requirements under County's regulations. These requirements are already listed under the Class I Permit for Coolidge Generating Station.

5.2 Federal Regulations

5.2.1 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.

5.2.2 40 CFR Part 60, Subpart A Standards of Performance for Stationary Combustion Turbines

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.

5.2.3 40 CFR Part 60, Subpart KKKK Standards of Performance for Stationary Combustion Turbines

This NSPS Subpart applies to stationary combustion turbines for which construction, modification or reconstruction commences after February 18, 2005. The sixteen (16) proposed natural gas-fired simple cycle stationary combustion turbines meet the affected facility definition under this standard. Therefore, the following NSPS requirements will apply to the proposed CTs under the Project.

(a) Comply with the NO_X emission limit of 25 ppm at 15 percent oxygen (O_2) or 1.2 lb/MWh (for combustion turbine firing natural gas with heat input greater than 50 MMBtu per hour and less than or equal to 850 MMBtu per hour) on a four (4) hour rolling average basis while the unit is operating at greater than or equal to 75% of peak load. (40 CFR § 60.4320 and Table 1, 40 CFR § 60.4350(h))

(b) Comply with the alternate NO_X emission limit of 96 ppm at 15 percent O_2 or 4.7 lb/MWh (for combustion turbine firing natural gas with output greater than 30 MW) on a four (4) hour rolling average basis when combustion turbines are operating at less than 75% of peak load. (40 CFR § 60.4320 and Table 1, 40 CFR § 60.4350(g))

(c) Comply with the SO_2 emission limit of 0.9 pounds per megawatt-hour gross output, or not burn any fuel which contains total potential sulfur emissions in excess of 0.060 lb of SO_2 per MMBtu heat input. (40 CFR § 60.4330)

(d) Compliance requirement – The simple cycle combustion turbines, SCR, and monitoring equipment must be operated and maintained in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunctions. (40 CFR § 60.4333)

(e) Option to use a NO_X continuous emissions monitoring system (CEMS). SRP will use the CEMS installed, certified, and operated in accordance with 40 CFR Part 75 Appendix A. (40 CFR §§ 60.4335(b) and 60.4345(a))

(f) The requirement to monitor fuel sulfur for SO_2 monitoring does not apply if potential sulfur emissions expressed as SO_2 are less than 0.060 lb/MMBtu. SRP proposes to use fuel tariff sheet or purchase contract information or representative fuel sampling performed per 40 Part 75 Appendix D to show that fuel sulfur will comply with the applicable limit. (CFR §§ 60.4360 and 60.4365)

(g) SRP proposes to use NO_X CEMS RATA as the initial NO_X performance test. (40 CFR § 60.4405)

(h) No annual performance test is required due to the presence of NO_X CEMS. (40 CFR § 60.4340(b)(1))

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

5.2.4 40 CFR Part 60, Subpart TTTT Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

This NSPS applies to carbon dioxide (CO_2) emissions from certain stationary combustion turbines. As specified in 40 CFR § 60.5509(a) of this subpart, the GHG standards included in this subpart apply to any steam generating unit, IGCC, or stationary combustion turbine, all of which are designated as electric generating units (EGUs), that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014 and that meets the applicability conditions below:

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

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

The sixteen (16) 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.

Per 40 CFR § 60.5520(a), the proposed CTs will be subject to the CO_2 emission standards specified in Table 2 of 40 CFR 60 Subpart TTTT. The proposed units are "non-base load" type as they will combust more than 90% natural gas on a heat input basis (100%), and SRP plans to limit net electric sales for each CT to less than its design efficiency (or 50% whichever is less), multiplied by its potential electric output on a 12-operating month basis or 3-year rolling average basis. Therefore, these units will be subject to the nominal CO_2 limitation of 120 lb per MMBtu on a 12-month rolling average basis (40 CFR § 60.5520, 40 CFR § 60.5525, and Table 2).

In 40 CFR § 60.5520(d), stationary combustion turbines are subject to a heat input-based standard in Table 2 of this subpart that are only permitted to burn one or more uniform fuels, as described in 40 CFR § 60.5520(d)(1), are only subject to the monitoring requirements in 40 CFR § 60.5520(d)(1) as follows:

> *Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (i.e., uniform fuels) that result in a consistent emission rate of 160 lb CO_2/mmBtu or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.*

The proposed simple cycle combustion turbines will be permitted to only burn natural gas which is classified as a uniform fuel. Therefore, per 40 CFR § 60.5520(d)(1), the proposed CTs are not subject to any monitoring or reporting requirements under this standard and are only required to maintain purchase records for the permitted fuels.

5.2.5 National Emission 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 single HAPs and combination of HAPs after the proposed project is proposed to be limited to less than 10 tons per year and 25 tons per year, respectively. With this project SRP is requesting to keep the station as an area source under 40 CFR § 63.2 for applicability of NESHAP requirements.

5.2.6 40 CFR Part 63, Subpart YYYY NESHAP for Stationary Combustion Turbines

Coolidge Generating Station is an area source of hazardous air pollutants. Therefore, the requirements of NESHAP 40 CFR Part 63 Subpart YYYY do not apply to this Project.

5.2.7 40 CFR 64 – Compliance Assurance Monitoring

The Compliance Assurance Monitoring ("CAM") program is codified in 40 CFR Part 64. CAM plan requirements apply to any pollutant specific emissions unit with uncontrolled potential emissions above the major source threshold (70 tpy for PM10 or 100 tpy of any other air pollutant) that uses a control device to achieve compliance with an emission limitation or standard. Only the uncontrolled NO_X and CO emissions for the simple cycle combustion turbines will exceed this threshold. SRP is proposing to use continuous emissions monitoring systems ("CEMS") for monitoring of NO_X and CO emissions from the proposed units. We request that the CEMS requirements be included in the Class I permit for COE. Thus, in accordance with 40 CFR § 64.2(b)(1)(vi), CAM plan requirements do not apply for NOx and CO emissions from the proposed units.

5.2.8 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 simple cycle combustion turbine fire natural gas and produce electricity for sale, these are affected units under the federal Acid Rain Program. SRP will submit an Acid Rain Permit application to EPA and provide a copy to PCAQD.

6.0 PROPOSED PERMIT TERMS AND CONDITIONS

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

As provided under Code § 3-1-084 and R18-2-306.01, SRP is proposing the following voluntary emission limitations for the existing and the proposed operations at the COE site to keep below the applicable 'major source' thresholds under R18-2-401(13)(a) and (b).

(A) Revise the existing Condition 4.C.1 as follows for the existing operations at the COE site.

> Operation of the facility, including the number of emission units (CTG's) operating along with the fire pump engine operation, the duration of unit-specific operation, start-up and shut-down events, and the unit-specific loading, shall be limited in combination such that emissions, including the emissions generated during start-up and shutdown events, of any of CO, NO_X, VOC, ~~PM10/~~PM2.5 and SO_2 from the facility shall not exceed a cap of 245 tons per 12-calendar-month period per pollutant **and of PM10 from the facility shall not exceed 69.9 tons per 12-calendar-month period**.

(B) Revise the existing Condition 5.C.1 as follows for the existing CTs at the COE site to include alternative limitations that apply under the NSPS 40 CFR 60 Subpart KKKK per 40 CFR §60.4325.

1. NO_X Emission Limitation NSPS Subpart KKKK [40 CFR §60.4325]

~~No gases shall be discharged to the atmosphere from the combustion turbine which contains greater than 25 ppm of nitrogen oxides at 15 percent oxygen or 150 ng/J of useful output.~~

(a) No gases shall be discharged to the atmosphere from the combustion turbine which contains greater than 25 ppm of nitrogen oxides at 15%

oxygen or 150 ng/J of useful output while the combustion turbine is operated at greater than or equal to 75% of the peak load.

(b) No gases shall be discharged to the atmosphere from the combustion turbine which contains greater than 96 ppm of nitrogen oxides at 15% oxygen or 590 ng/J of useful output while the combustion turbine is operated at less than 75% of the peak load.

(C) With the addition of alternative NO_X limit of 96 ppm for the existing CTs under Condition 5.C.1, Conditions 5.D.1 and 2 are redundant and should be deleted.

~~1. Definitions~~

~~a. "Start-up" is defined as the 32-minute period following an initiation of fuel flow.~~

~~b. "Shutdown" is defined as the 12-minute period prior to shut-off the fuel supply.~~

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

~~2. Start-up and Shutdown Emissions~~

~~Anytime during the start-up or shutdown of the units, if the NO_X emissions exceed 25 ppm, then in accordance with the definition of excess emissions in Section §6.E.1 of this permit, these excess emissions will be reported monthly to the department (All Modes Report). Although these excess emissions are not considered to be violations of the NO_X emission limit, Permittee shall continue to exercise "good combustion practice" consisting of adherence to standard operating procedure.~~

(D) SRP is proposing changes to Condition 5.H to correct an error in the regulatory citation reference and corrections to the exponent in the particulate matter equations.

1. SIP Limitation [Currently federally enforceable pursuant to ~~PGAQCD~~ **PCAQCD** Reg. 7-3-1.7 (3/31/75) approved as a SIP element at 43 FR 50531 (11/15/78)]

For equipment with a heat input capacity of ~~greater ten but~~ less than 4,000 million Btu per hour, particulate emissions shall not exceed[1]:

~~E = 1.02X-.231~~ **$E = 1.02X^{-.231}$**, where E = allowable rate of emissions in lbs per million BTU heat input, and

X = maximum heat input capacity in million BTU per hour.

2. Current Code Limitation (§5-23-1010)

For equipment with a heat input capacity of less than 4,200 million Btu per hour, particulate emissions shall not exceed3:

E = ~~1.02Q0.769~~ **$1.02Q^{0.769}$**, where E = maximum emissions in lbs./hr.

Q = maximum heat input of all operating fuel burning units on a plant premises, in million BTU per hour.

(E) Based on the guidance from PCAQCD and testing requirements for similar facilities, SRP requests changes to the performance testing requirements in Condition 6 to require two CTs tested per permit period (5 years), for a representative sampling of all units. Coolidge Generating Station historically operates at 1-2% of the allowed VOC and PM10 emission limits of 245 tons per year for each pollutant. Further for NO_X and CO CEMS are used as the compliance demonstration and therefore only the RATAs are required. For SO_2 gas sampling is used to show compliance. The permit correctly identifies that the RATA is conducted for CO but for NO_X the current permit requires annual performance testing which is not required under Part 60 Subpart KKKK. Proposed changes are shown below

Condition 6.A.1

1. Performance Tests [40 CFR 60.8, Code §§3-1-160 & 3-1-170)

At least once during the 5-year permit term, Permittee shall conduct performance tests for VOCs and PM10. At least two CTs shall be selected for testing and used to represent all of the identical CTs at the facility to

meet this requirement and used for emissions calculations and emissions inventory. Selection of the CTs tested shall be rotated for each subsequent testing. ~~Within one year of the previous performance test but no later than fourteen (14) months of the test,~~ Permittee shall conduct performance tests, using standard test methods specified below, or equivalent methods as approved by the District pursuant to approval of the test plan required below. The tests shall be conducted using standard test methods approved by the EPA (40 CFR Part 60). These tests shall be performed at the maximum practical production rate. The continuous monitoring systems required by this permit shall be in place and operating prior to conducting the performance tests. Each performance tests shall address:

~~a. Nitrogen oxides emissions Ref. Part 60, App. A, Ref. Method 7E or 20.~~
~~b. Carbon monoxide emissions Ref. Part 60, App. A, Ref. Method 10~~
c. Particulate matter emissions (filterable PM10) Ref. Part 60, App. A, Ref. Method
5 or 201A and (condensable PM10) Method 202.
d. Volatile organic compound emissions Ref. Part 60, App. A, Ref. Method 25a
~~e. Opacity Ref. Part 60, App. A, Ref. Method 9, 40 CFR §60.11.~~

Condition 6.A.3

3. Subsequent Performance Testing (Code §3-1-050)
   a. PM Non-NSPS Testing Requirements
      Permittee shall conduct ~~annual~~ testing of turbines for particulate matter using the testing methods listed in Section §6.A.1 of this permit.
   b. CO Non-NSPS Testing Requirements
      Performance testing for carbon monoxide shall be covered under annual Relative Accuracy Test Audits (RATA).
   c. VOC Non-NSPS Testing Requirements
      Permittee shall conduct ~~annual~~ testing of turbines for volatile organic compounds using the testing methods listed in Section §6.A.1 of this permit.

d. NO_X NSPS Testing Requirements [40 CFR Part 60, Subpart KKKK §60.4400]

Performance testing for nitrogen oxides shall be covered under annual Relative Accuracy Test Audits (RATA).

~~Permittee shall conduct subsequent nitrogen oxides performance tests on an annual basis, no more than 14 calendar months following the previous performance test. Test method listed in Section §6.A.1 of this permit shall be used.~~

e. SO_2 NSPS Testing Requirements [40 CFR Part 60, Subpart KKKK, §60.4415]

Permittee shall conduct subsequent sulfur dioxide performance tests on an annual basis, no more than 14 calendar months following the previous performance test. One of the three methodologies described in Section §60.4415 of the Subpart KKKK can be used to conduct the performance tests.

(F) SRP requests deletion to application of the bias adjustment factor under Condition 6.C.1.b for demonstration of compliance with the 245-tons per year synthetic minor limit calculations of the 12-month rolling average. Any adjustments should be applied only to future emissions as required by the Federal regulations (40 CFR Part 75). The application of a bias adjustment factor retroactively would create inconsistencies with reported emissions under the Acid Rain Program and the emissions reported on a semiannual basis as required by Condition 6.H.

1. Compliance with Synthetic Minor Limitations

~~a.~~ To comply with the operational limitations as specified in Section §4.C of this permit, Permittee shall on the 10th day of each month calculate actual 12 month rolling emissions and a 12 month rolling emissions "budget." This emission budget shall be based on the past 10 months of historical emissions data and the amount of emissions (or emissions budget) that could be allowable in the upcoming 2 months (including the current month) without exceeding the 245 tons per year per pollutant synthetic minor limit.

~~b. To the extent the application of the bias adjustment factor as determined under §6.D.4 results in an increase of emissions during the reference period since the previous RATA test, by the 10th of the month following the completion of the latest RATA test, permittee shall correspondingly demonstrate continued continuous compliance with the 245 ton per year synthetic minor limit by recalculating the 12 month rolling average of emissions for each prior month affected by application of the bias adjustment factor.~~

(G) SRP requests the removal of the 30-day rolling average requirement in Condition 6.E.1. COE units are subject to the simple cycle unit without heat recovery requirements described in 40 CFR § 60.4350.g, which only references a 4-hour rolling average requirement.

1. An excess emission is any unit operating period in which the 4-hour ~~or 30-day~~ rolling average NOX emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NOX emission rate" is the arithmetic average of the average NOX emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOX emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOX emission rate is obtained for at least 3 of the 4 hours.

(H) Add the following permit conditions for the sixteen combustion turbines ("CTs") (CT13 through CT28) and seven wet surface air coolers ("WSAC") (WSAC1 through WSAC7) to be permitted under the CT Project.

(1) Emission Limitations

a. The Permittee shall not cause or allow the PM/PM10/PM2.5 emissions from CT13 through CT28 and WSAC1 through WSAC7 more than 69.9 tons per 12-month rolling total sum (combined totals for all emissions units noted here including normal operation and startup/shutdown duration).

b. The Permittee shall not cause or allow the NO_X emissions from CT13 through CT28 more than 249.9 tons per 12-month rolling total sum (combined total for all emissions units noted here including normal operation and startup/shutdown duration).

c. The Permittee shall not cause or allow the VOC emissions from CT13 through CT28 more than 249.9 tons per 12-month rolling total sum (combined totals for all emissions units noted here including normal operation and startup/shutdown duration).

d. The Permittee shall not cause or allow the CO emissions from CT13 through CT28 more than 249.9 tons per 12-month rolling total sum (combined totals for all emissions units noted here including normal operation and startup/shutdown duration).

(2) Compliance Demonstration

a. Within 60-days after achieving maximum production rate of each CT (CT13 through CT28), 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

b. The Permittee shall document the drift specification for the drift eliminators used to control particulate matter emissions from the WSAC units (WSAC1 through WSAC7) from the manufacturer's specification or other engineering information.

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

a. The Permittee shall install, calibrate, maintain, and operate continuous emissions monitoring systems on CT13 through CT28, and record the output of each system, for measuring nitrogen oxides 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 oxides and carbon monoxide emissions from CT13 through CT28 emitted for the previous month and for the preceding 12- 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) Monitoring Requirements – Particulate Matter

a. The Permittee shall install, calibrate, maintain, and operate a continuous monitoring system on CT13 through CT28, and record the output of the system, for measuring the amount of fuel used. Monitoring equipment required under this subsection shall be installed and operated in accord pursuant to a plan submitted to the District by the permittee.

b. The Permittee shall maintain records of number of startups for CT13 through CT28 pursuant to a plan submitted to the District by the permittee.

c. Except as provided below, the following PM/PM10/PM2.5 emission factors have been approved by the Control Officer and shall be used to calculate emissions from CT13 through CT28: 0.009 pounds per MMBtu heat input for non-startup periods, 5.1 pounds per shutdown and startup event (combined). For each simple-cycle combustion turbine, once initial performance testing has been performed per Condition ___, the highest PM/PM10/PM2.5 emission factor for non-startup periods for such simple-cycle combustion turbine (expressed in pounds per MMBtu heat input) shall be used until superseded by the results of subsequent performance testing.

d. The Permittee shall install, calibrate, maintain, and operate a monitoring system on WSAC1 through WSAC7, and record the output of the system, for measuring the amount of recirculation water used in the system. Monitoring equipment required under this subsection shall be installed and operated in accord pursuant to a plan submitted to the District by the permittee.

e. Once per quarter, the Permittee shall measure conductivity (as surrogate for TDS) or TDS for recirculation water for WSAC1 through WSAC7 pursuant to a plan submitted to the District by the permittee.

f. Monthly PM/PM10/PM2.5 emissions calculations:

   i. The Permittee shall calculate the quantity of emissions monthly during normal operation for PM/PM10/PM2.5 by multiplying the aggregate fuel flows/heat input for CT13 through CT28 by the corresponding PM/PM10/PM2.5 emission factors established per Condition ___.c above.

   ii. The permittee shall calculate the quantity of emissions monthly for startup and shutdown events for PM/PM10/PM2.5 by multiplying the number of events for CT13 through CT28 by the corresponding PM/PM10/PM2.5 emission factor established per Condition ___.c above.

iii. The permittee shall calculate the quantity of emissions monthly for WSAC1 through WSAC16 by using the following equation.

$$E = k * Q * 60\left[\frac{min}{hour}\right] * 8.345\left[lb\frac{H2O}{gallon}\right] * \left[\frac{CTDS}{10^6}\right] * \left[\frac{DL}{100}\right]$$

Where,	E	= Particulate matter emissions, pounds per hour
	Q	= Circulating water flow rate, gallons per minute
	CTDS	= Circulating water total dissolved solids, ppm
	DL	= Drift loss, %
	k	= Particle size multiplier for PM10 and PM2.5[13]

g. On a calendar-month basis, Permittee shall generate a record of cumulative actual PM/PM10/PM2.5 emissions from CT13 through CT28 and WSAC1 through WSAC7 emitted for the previous month and for the preceding 12- months and shall compare that total to the annual PM/PM10/PM2.5 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 ______.

(5) Monitoring Requirements – Volatile Organic Compound

a. Except as provided below, the following VOC emission factors have been approved by the Control Officer and shall be used to calculate emissions from CT13 through CT28: 0.009 pounds per MMBtu heat input for non-startup periods, 2.7 pounds per shutdown and startup

[13] PM10 and PM2.5 particle size multiplier from "*Calculating Realistic PM10 Emissions from Cooling Towers*"; Reisman & Frisbie (uses EPRI wet droplet size distribution), Environmental Progress, 2002.

event (combined). For each simple-cycle combustion turbine, once initial performance testing has been performed per Condition ___, the highest VOC emission factor for non-startup periods for such simple-cycle combustion turbine (expressed in pounds per MMBtu heat input) shall be used until superseded by the results of subsequent performance testing.

b. Monthly VOC emissions calculations:
    i. The Permittee shall calculate the quantity of emissions monthly during normal operation for VOC by multiplying the aggregate fuel flows/heat input for CT13 through CT28 by the corresponding VOC emission factors established per Condition ___.c above.
    ii. The permittee shall calculate the quantity of emissions monthly for startup and shutdown events for VOC by multiplying the number of events for CT13 through CT28 by the corresponding VOC emission factor established per Condition ___.c above.

c. On a calendar-month basis, Permittee shall generate a record of cumulative actual VOC emissions from CT13 through CT28 emitted for the previous month and for the preceding 12- months and shall compare that total to the annual VOC emission 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 ______.

APPENDIX A

CLASS I PERMIT REVISION APPLICATION FORMS

Pinal County Air Quality Control District

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

PINAL COUNTY
WIDE OPEN OPPORTUNITY

Permit Application

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

1. Permit to be issued to: Salt River Project Agricultural Improvement and Power District
   (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): Coolidge Generating Station

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

5. Plant/Site Manager: Maria Roberts Phone: (602) 236-4328 Fax:

6. Contact Person: Zachary J Harbrin Phone: (602) 236-5779 Fax:
   Email Address: Zachary.Harbin@srpnet.com

7. Equipment/Plant Location or Proposed Location Address: 859 East Randolph Road
   City: Coolidge Zip: 85128 Parcel #: 503-34-015B
   Section/Township/Range:
   Latitude/Longitude: 32.55.01N, 111.30.15W Elevation: 1443

8. General Nature of Business: Electric generation
   Standard Industrial Classification Code: 4911

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)

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

For renewal or modification, include existing permit number: V20676.A01

Date of Commencement of Construction or Modification: Planned for February 2022

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

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

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

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

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

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

Maria Roberts

Signature of Responsible Official of Organization

Maria Roberts

Typed or Printed Name of Signer

Director, Coolidge Generating Station

Official Title of Signer

8/27/2021

Date

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
   (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): Coolidge Generating Station

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

5. Plant/Site Manager: Maria Roberts Phone: (602) 236-4328 Fax:

6. Contact Person: Zachary J Harbrin Phone: (602) 236-5779 Fax:
   Email Address: Zachary.Harbin@srpnet.com

7. Equipment/Plant Location or Proposed Location Address: 859 East Randolph Road
   City: Coolidge Zip: 85128 Parcel #: 503-34-015B
   Section/Township/Range:
   Latitude/Longitude: 32.55.01N, 111.30.15W Elevation: 1443

8. General Nature of Business: Electric generation
   Standard Industrial Classification Code: 4911

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)

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

For renewal or modification, include existing permit number: V20676.A01

Date of Commencement of Construction or Modification: Planned for February 2022

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

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

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

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

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

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

Maria Roberts

Signature of Responsible Official of Organization

Maria Roberts

Typed or Printed Name of Signer

Director, Coolidge Generating Station

Official Title of Signer

8/27/2021

Date

APPENDIX B

EMISSIONS CALCULATIONS

SRP Coolidge Generating Station

Table 1: Operating Scenario Inputs

Coolidge Generating Station Expansion Operating Parameters

Simple Cycle Aero	GE LM6000PC			
Number of Units	16			
Annual operations per turbine	1,000	Hours/year		
Annual utilization factor	11%			
SU/SD events, per GT	730	Number/year		Two per day
Start Duration	30	minutes		
Shutdown Duration	9	minutes		
Natural Gas (HHV)	1,015	Btu/cf		
Natural Gas (LHV)	914	Btu/cf		
Sulfur concentration in NG	0.25	gr/100 cf	0.001	lb of SO2/MMBtu
Annual average from fuel specification				
Lead Emission Factor	4.93E-07	lb/MMBtu		

Lead (Pb) emission factor is from the U.S. EPA's Compilation of Air Pollutant Emission

Table 2: Greenhouse Gas Emissions Factors

		CO2 (1)	CH4 (2)	N2O (3)	SF6 (4)	kg =	2.2046 lb
Natural Gas (kg/MMBtu)		53.06	0.001	0.0001	NA		
GWP		1	25	298	22800		
Natural Gas CO2e=	117.10 lb/MMBtu						
Natural Gas CO2=	116.98 lb/MMBtu						

Notes:
1. 40 CFR 98, Table C-1 (revised 11/29/13).
2. 40 CFR 98, Table C-2 (revised 11/29/13).
3. 40 CFR 98, Table A-1 (revised 11/29/13).
4. Sulfur hexafluoride (SF6) will be used as an insulating medium in circuit breakers.

The IEC standard for SF6 leakage is less than 0.5%; the NEMA leakage standard for new circuit breakers is 0.1%. A maximum leakage rate of 0.5% per year is assumed.

Table 3: GE LM6000PC Aero Simple Cycle Unit Performance Normal Operation

Output 49.5 MW

Ambient Conditions																
Ambient Temperature	°F	10	10	10	59	59	59	59	59	59	102	102	102	102	102	102
Ambient Pressure	psia	13.968	13.968	13.968	13.968	13.968	13.968	13.968	13.968	13.968	13.968	13.968	13.968	13.968	13.968	13.968
Ambient Relative Humidity	%	60	60	60	60	60	60	60	60	60	20	20	20	20	20	20
Gas Turbine																
GT Fuel Type		Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Number of Gas Turbines operating per Block		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
GT load fraction	-	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
Evap Cooler status		Off	Off	Off	On	On	On	Off	Off	Off	On	On	On	Off	Off	Off
SPRINT status		Off	Off	Off	On	On	Off	Off	Off	Off	On	On	Off	Off	Off	Off
Gas turbine water injection flow rate	klb/h	21.3	14.5	9.1	19	12	9.9	19.7	13.7	8.8	15.8	9.9	8.7	12.3	9.1	6.4
Plant Performance (not guaranteed)																
GT power (per GT)	kW	48269	36202	24135	49029	36772	24515	41985	31488	20992	45221	33916	22611	25507	19130	12753
GT Heat Cons (HHV)	MMBtu/h	471.3	376.1	285.2	489.8	385.8	288.4	424.3	341.4	263.1	456	363	274.2	298.2	250.6	205.8
SCR Exit Emissions (per unit)																
NOx Volume fraction, dry, at 15 % O2	ppm	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
NOx mass flow rate (as NO2)	lb/h	4.3	3.4	2.6	4.4	3.5	2.6	3.8	3.1	2.4	4.1	3.3	2.5	2.7	2.3	1.9
CO Volume fraction, dry, at 15 % O2	ppm	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
CO mass flow rate	lb/h	7.3	5.8	4.4	7.6	6	4.5	6.5	5.3	4.1	7	5.6	4.2	4.6	3.9	3.2
VOC Volume fraction, dry, at 15 % O2	ppm	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
VOC mass flow rate (as methane)	lb/h	4.2	3.3	2.5	4.3	3.4	2.6	3.8	3	2.3	4	3.2	2.4	2.6	2.2	1.8
NH3 Volume fraction, dry, at 15 % O2	ppm	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NH3 mass flow rate	lb/h	3.2	2.5	1.9	3.3	2.6	1.9	2.8	2.3	1.8	3.1	2.4	1.8	2	1.7	1.4
Total Particulates	lb/h	4.18	4.14	4.11	4.19	4.15	4.11	4.16	4.13	4.1	4.17	4.14	4.11	4.11	4.1	4.08
Stack CO2 mass flow rate, including Pe	lb/h	57,900	46,300	35,100	60,200	47,400	35,500	52,200	42,000	32,400	56,100	44,700	33,800	36,900	30,900	25,400

Table 4: GE LM6000PC Aero Simple Cycle Unit Performance Startup and Shutdown

Event	Duration (min)	Heat Input (MMBTU - HHV)	NOx (lb)	CO (lb)	VOC (lb)	PM/PM10 /PM2.5 (lb)
Startup	30	199.6	14.3	15.7	1.8	4.1
Shutdown	9	33.7	3.9	16.6	0.9	1

Table 5: GE LM6000PC Aero Simple Cycle Unit Emissions

Operating Parameters	Operation (Hours/year)	Heat Input* (MMBtu/hr)	
SC GT Operation	1,000	490	
For simple cycle units SU&SD hours are in addition to the capacity factor			
		SU&SD	
SC GT Operating Scenarios (events/year)		730	
SC GT Heat Input* for minimum load (MMBtu)		200	represents heat input for MECL for partial hour

Pollutants	One SC GT Emissions** Max Hourly (lb/hour)	Annual (tons/year)	Emissions SU&SD (tons/year)	Emissions Total for One CT (tons/year)
NOx	4.4	2.2	6.6	8.8
CO	7.6	3.8	11.8	15.6
VOC	4.3	2.2	1.0	3.1
SO2***	0.5	0.2	0.05	0.3
PM	4.2	2.1	1.9	4.0
PM10	4.2	2.1	1.9	4.0
PM2.5	4.2	2.1	1.9	4.0
H2SO4****	0.05	0.02	0.00	0.0
Lead	2.41E-04	0.000	0.000	0.0
CO2	57,295	28,647	5,539	34,187
CO2e	57,356	28,678	5,545	34,223

**Heat input in HHV representing maximum for cold ambient temperature case.*

***NOx, CO, VOC, PM/PM10/PM2.5 annual emissions based on the short term emission rate for 59 °F ambient temperature case.*

****SO_2 emission factor of 0.001 lb/MMBtu based on combustion of pipeline quality natural gas and assuming a maximum S concentration of 0.25 gr/100 cf.*

*****The sulfuric acid mist emissions are estimated as 10% of the SO_2 emissions.*

Table 6: Wet Surface Air Coolers Emissions

k Particle Size Multiplier*		
PM	PM10	PM2.5
100%	29.97%	0.18%

	WSAC	Q per Unit**	Q (total)	C_{TDS}	%DL	Emissions (lb/hour) (total)			Emissions (TPY) (total)***		
	Number	gal/min	gal/min	ppm	%	PM	PM10	PM2.5	PM	PM10	PM2.5
WSAC	7	10,600	74,200	5,000	0.0005%	0.93	0.28	0.002	0.46	0.14	0.001
Six cells per WSAC											

*PM10 and PM2.5 particle size multiplier from "Calculating Realistic PM10 Emissions from Cooling Towers"; Reisman & Frisbie (uses EPRI wet droplet size distribution).
**Q per WSAC engineering estimate.
*** Annual emissions based on the 1,000 hours per year for each unit.

WSAC PM emissions are calculated based on the maximum circulating water flow rate, the design total dissolved solids (TDS) for the circulating

$$E = Q \times k \times (60\ \text{min/hr})\ (8.345\ \text{lb water/gal}) \times (C_{TDS}/1{,}000{,}000) \times (DL/100)$$

Where,
- E = Particulate matter emissions, pounds per hour
- Q = Maximum circulating water flow rate, gallons per minute
- C_{TDS} = Circulating water total dissolved solids, parts per million (ppm)
- k = Particle Size Multiplier

Table 7: Emissions Summary

Coolidge Generating Station Summary of Emissions for All Units under the Expansion

	Number	Model
Simple Cycle Aero:	16	LM6000PC
Total Capacity:	792	MW

	Potential to Emit (tons/year)					
	Simple Cycle Turbines		WSAC	Total	PSD/NNSR MSS	
Pollutants	Normal	SU&SD			(tons/year)	Over MSS?
NOx	35.2	106.3		141.5	250	No
CO	60.8	188.6		249.4	250	No
VOC	34.4	15.8		50.2	250	No
SO2	3.9	0.8		4.7	250	No
PM	33.5	29.8	0.5	63.8	250	No
PM10	33.5	29.8	0.1	63.4	70	No
PM2.5	33.5	29.8	0.0	63.3	250	No
H2SO4	0.39	0.08		0.47	250	No
Lead	0.0019	3.73E-04		0.00	250	No
CO2	458,359	88,631		546,990	NA	
CO2e	458,845	88,725		547,569	NA	

APPENDIX B

SRP Modeling Report for Class I Title V Air Permit Application

AIR DISPERSION MODELING FOR THE PROPOSED EXPANSION OF THE COOLIDGE GENERATING STATION

Prepared for:
Salt River Project Agricultural Improvement and Power District
1521 N. Mill Avenue
Tempe, Arizona 85281

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

September 2021

Table of Contents

List of Tables

List of Figures

1.0 INTRODUCTION

This document presents the results of the air quality dispersion modeling analysis conducted for the proposed expansion of the Coolidge Generating Station (Coolidge) owned and operated by the Salt River Project Agricultural Improvement and Power District (SRP) in Pinal County, Arizona.

The analysis evaluated emissions of each criteria pollutant that triggered minor New Source Review (NSR) as defined in R18-2-302 of the Arizona Administrative Code (AAC). The project will trigger minor NSR for all criteria pollutants except lead (Pb) and sulfur dioxide (SO_2). The criteria pollutant analysis was conducted to ensure that the proposed project will not cause or contribute to air pollution in violation of a National Ambient Air Quality Standard (NAAQS). Since the SRP Coolidge facility is located in an area of Pinal County which is classified as non-attainment for particulate matter with an aerodynamic diameter of less than 10 microns (PM10), the modeling analysis addressed the Arizona Department of Environmental Quality's (ADEQ) procedures for modeling demonstrations for both attainment and nonattainment pollutants.

The analysis conforms with the modeling procedures outlined in the U.S. Environmental Protection Agency's (EPA) Guideline on Air Quality Models[1] (Guideline), the ADEQ's Air Dispersion Modeling Guidelines for Arizona Air Quality Permits,[2] and associated EPA modeling policy and guidance. The modeling analysis also conforms with the modeling protocol submitted to the Pinal County Air Quality Control District (PCAQCD) on August 24, 2021. The PCAQCD subsequently requested revisions which have been addressed herein.

2.0 PROJECT DESCRIPTION

The proposed Coolidge expansion project involves the construction and operation of 16 new simple cycle aeroderivative combustion turbine generators (CTGs). In addition, the project includes addition of 7 wet surface air coolers (WSACs) for both the existing and the new CTGs. The project will result in potential emissions of carbon monoxide (CO), nitrogen oxides (NOx), volatile organic compounds (VOC), particulate matter with an aerodynamic diameter of less than 2.5 microns (PM2.5), and PM10 that are in excess of the minor NSR thresholds in R18-2-101(101). These pollutants are therefore subject to minor NSR review and were also conservatively evaluated for ambient impacts from the project using the air quality modeling analysis.[a]

[a] The proposed project is not subject to major NSR for any regulated NSR pollutant.

3.0 SITE DESCRIPTION

The Coolidge Generating Station is located in the City of Coolidge in Pinal County, approximately 16 kilometers (10 miles) southwest of Florence, Arizona. The approximate Universal Transverse Mercator (UTM) coordinates of the facility are 452,860 meters east and 3,642,300 meters north (UTM Zone 12, NAD 83). SRP currently operates 12 simple-cycle CTGs at this location. Figure 1 shows the general location of the facility. Figure 2 shows the specific facility location.

The facility is approximately 427m (1400ft) above mean sea level. The portion of Pinal County where the facility is located is classified as attainment or unclassified for all criteria pollutants other than PM10, for which the area is classified as nonattainment.

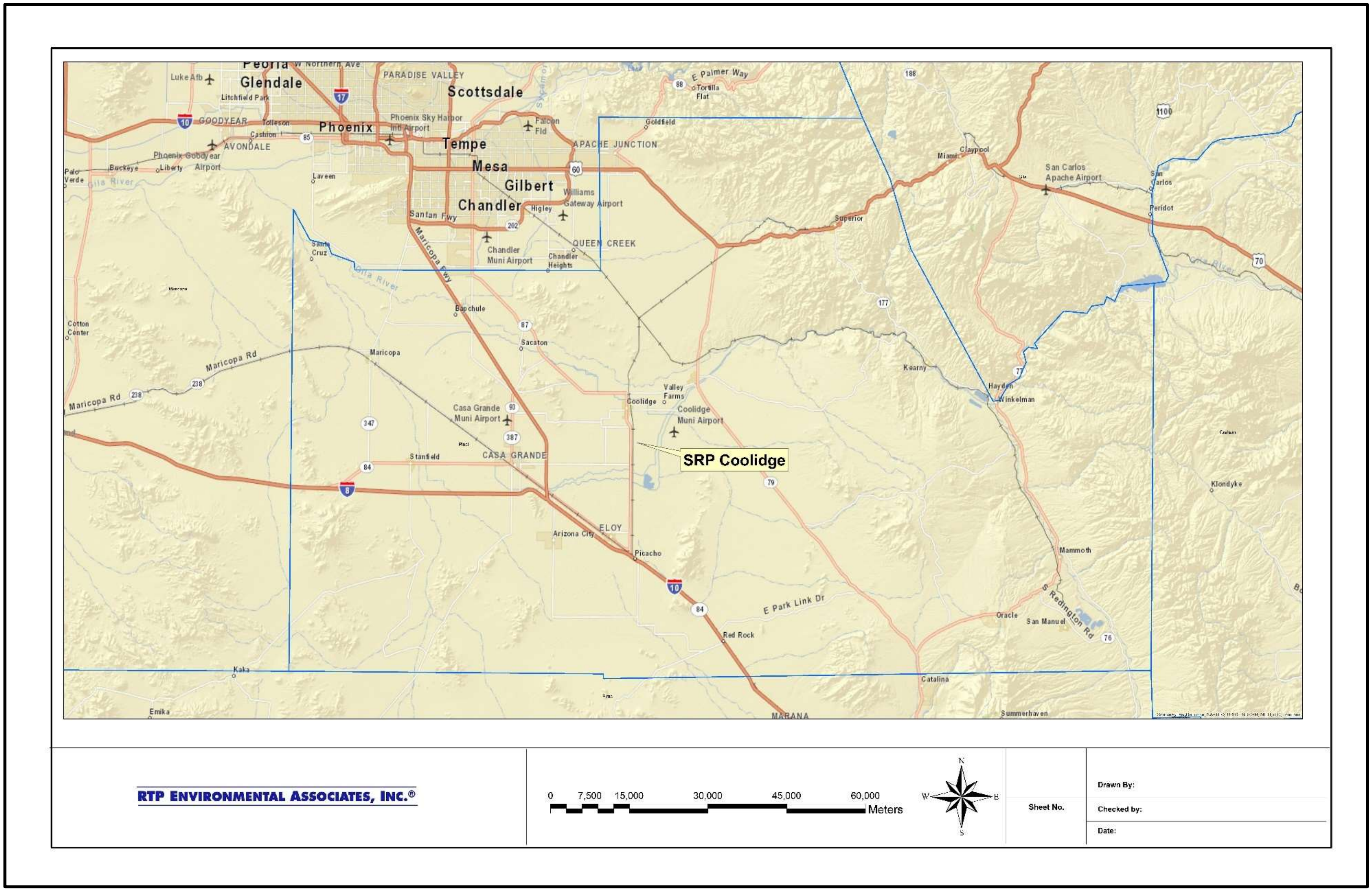


Figure 1. General Location of the SRP Coolidge Generating Station

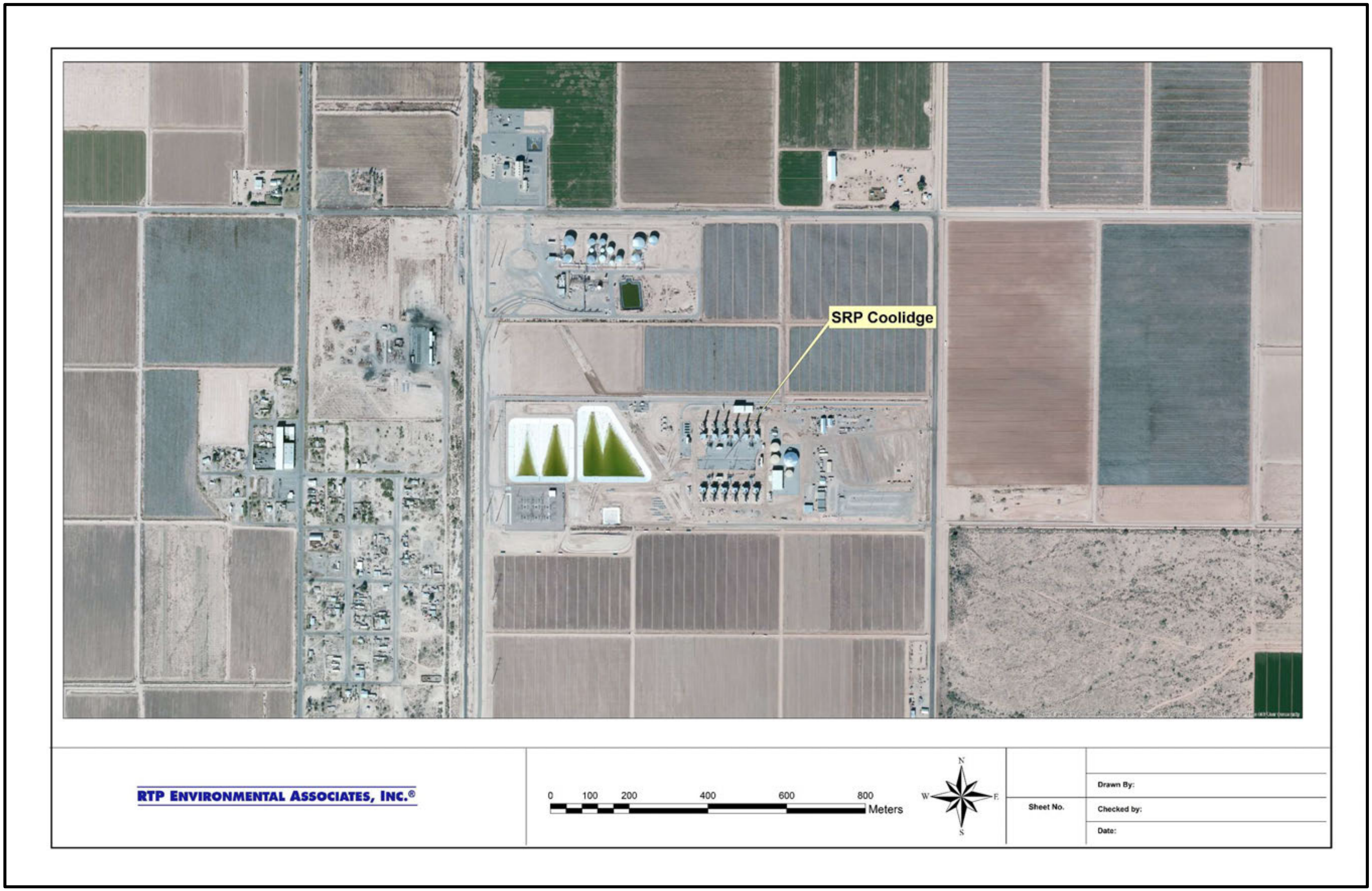


Figure 2. Specific Location of the SRP Coolidge Generating Station

4.0 MODEL SELECTION AND MODEL INPUT

4.1 Model Selection

The latest version of the AMS/EPA Regulatory Model (AERMOD, Version 21112) was used to conduct the modeling analyses. 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 most appropriate model for calculating ambient concentrations near the facility 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 also 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 Guideline.

Oris Solution's BEEST Graphical User Interface (GUI) was used to run AERMOD. The GUI uses an altered version of the AERMOD code to allow for flexibility in the file naming convention. The dispersion algorithms of AERMOD are not altered. Therefore, there is no need for a model equivalency evaluation pursuant to Section 3.2 of 40 CFR 51, Appendix W.

4.2 Control Options and Land Use

AERMOD was run in the regulatory default mode for all pollutants with the default rural dispersion coefficients. The use of rural dispersion coefficients is supported by the

Land Use Procedure consistent with subsection 7.2.1.1.b.i of the Guideline and Section 5.1 of the AERMOD Implementation Guide. The USGS 2016 National Land Cover Data ("NLCD") within 3km of the site were converted to Auer 1978 land use types and evaluated.[3] It was determined that the land use in the vicinity of the facility is predominantly rural as defined by Auer (less than 50% of the area is classified as urban - Figure 3). Only the red and dark red regions in Figure 3 (NLCD categories 23 and 24) are considered urban. The potential for urban heat island effects, which are regional in character, was considered and determined not to be of concern.

4.3 Source Data

Source Characterization

Point Sources

Only point sources required evaluation. The existing turbines currently vent, and the new turbines will vent, to stacks with a well defined opening. The turbines were therefore modeled as point sources in AERMOD. The WSACs were also modeled as point sources. Each cell was modeled as a separate source. All source locations were based upon a NAD83, UTM Zone 12 projection. Attachment A provides the modeling input data.

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 and to calculate the GEP formula stack height used to justify stack height credit for stacks to be constructed in excess of 65m. Procedures used were in accordance with those described in the EPA Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations-Revised)4. GEP formula stack height, as defined in §3-1-177(B) of the PCAQCD Regulations, is expressed as GEP = H_b + 1.5L, where H_b is the building height and L is the lesser of the building height or maximum projected width. Building/structure locations were determined from facility plot plans and aerial photos. The structure locations and

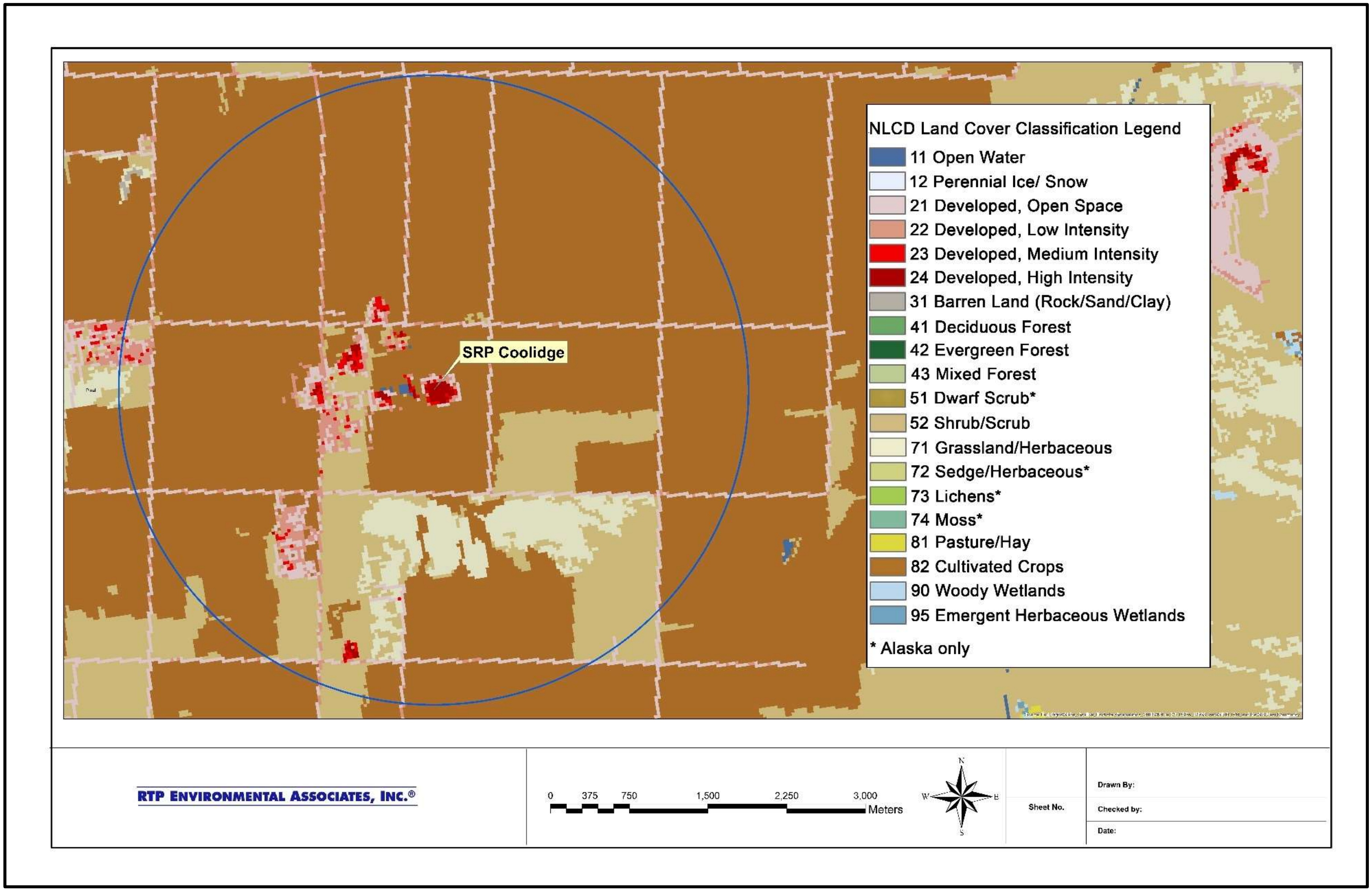


Figure 3. Land Use within Three Kilometers (3km Radius Shown)

heights were input to the EPA's Building Profile Input Program (BPIP-PRIME) computer program to calculate the direction-specific building dimensions needed for AERMOD. The proposed configuration of the facility is shown in Figure 4.

4.4 Monitored Background Data

Pursuant to ADEQ's Modeling Guidelines, background pollutant concentrations must be included in NAAQS analyses for both Prevention of Significant Deterioration (PSD) and non-PSD (minor NSR) applications. In general, the background concentrations are intended to account for sources not explicitly included in the modeling. The background concentrations are added to the modeled concentrations to assess NAAQS compliance.

The project requires modeling to assess NAAQS compliance for all regulated pollutants except SO_2 and lead. Even though the SRP Coolidge facility is in an area classified as nonattainment for PM10, the ADEQ's Modeling Guidelines allow for a facility to model facility-wide emissions and add the model results to representative background concentrations to demonstrate concentrations below the NAAQS. Background data are therefore needed for PM10, PM2.5, NO_2, CO and ozone.

There are existing ambient monitors within 100 miles of the facility (Figure 5). Existing monitoring data have been evaluated in relation to the criteria provided in EPA's Ambient Monitoring Guidelines[5] as being representative of the SRP Coolidge site.

Monitor Location

All proposed monitors, with the exception of Alamo Lake, are within 80 kilometers of the SRP facility. None of the selected monitors are subject to influence of any major, localized industry. All monitors therefore provide an adequate representation of the air quality in the vicinity of the SRP site.

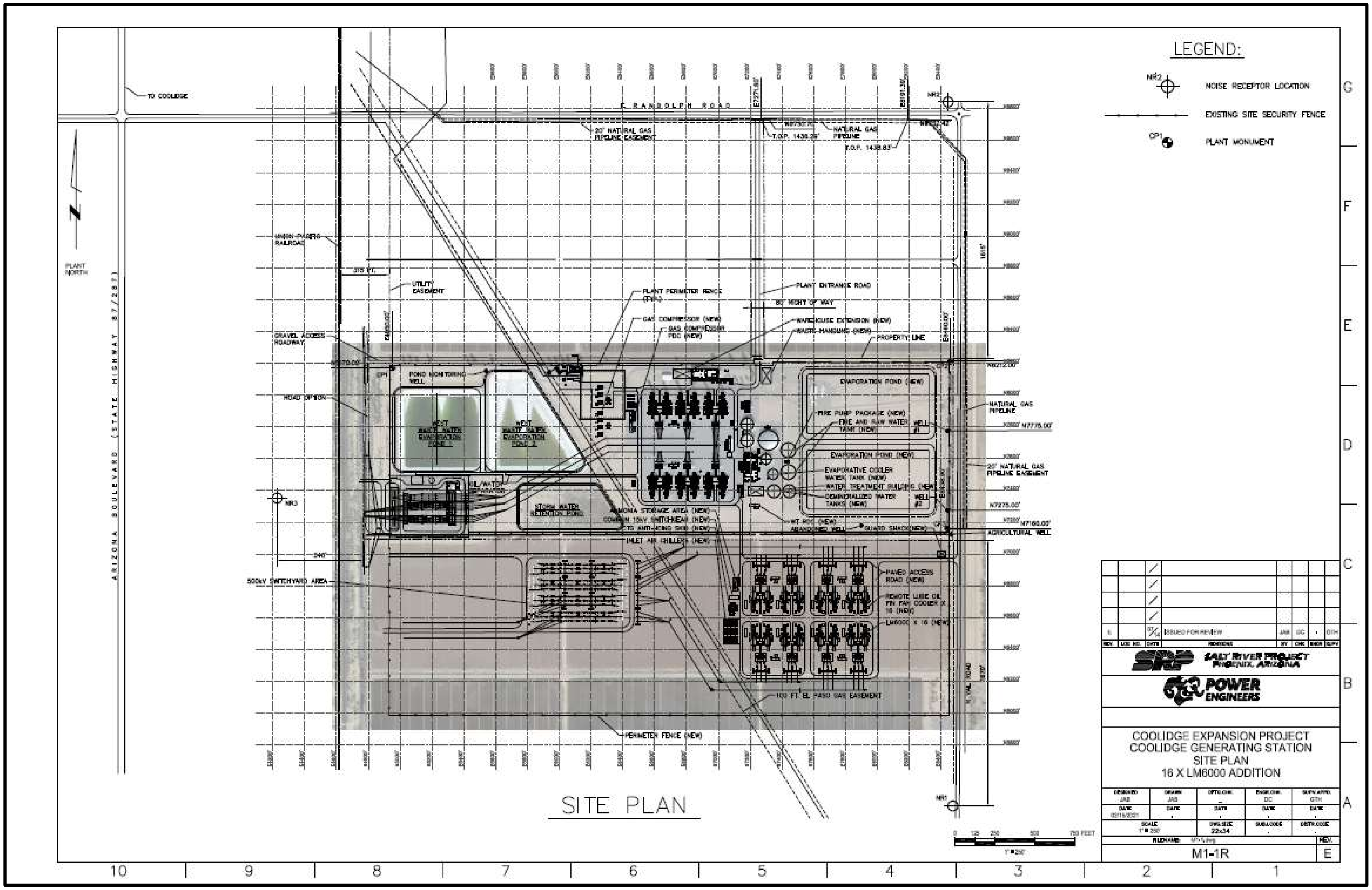


Figure 4. Preliminary SRP Coolidge Plot Plan

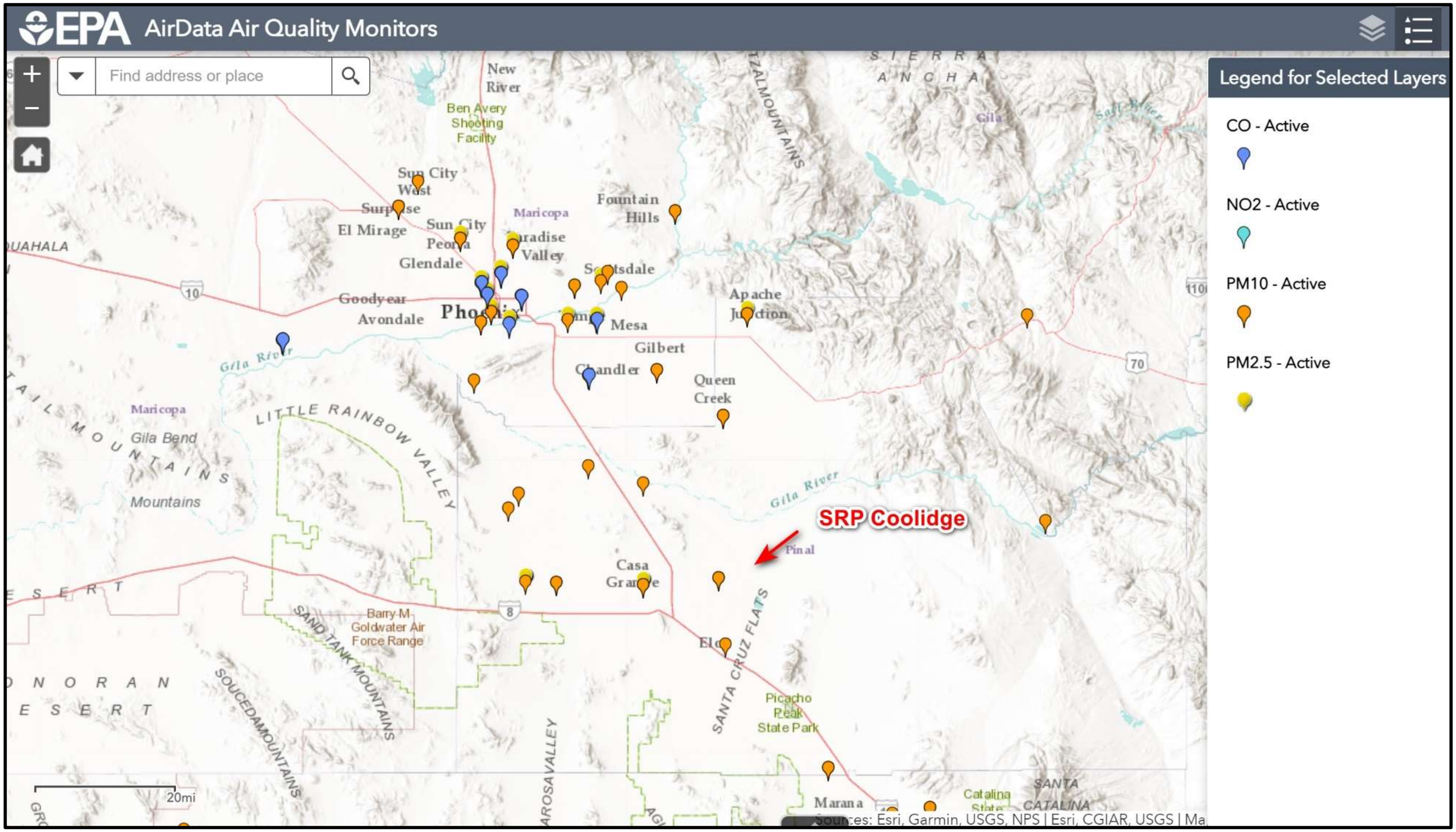


Figure 5. Ambient Monitors in the Vicinity of the SRP Coolidge Facility

There are very few active NO_2 monitors in Arizona and nearly all monitoring sites are located in the Phoenix/Tucson metropolitan areas. SRP has elected to conservatively include the annual NO_2 concentrations as measured in Tucson. While the climatology and topography of these metropolitan areas are representative of the SRP Coolidge location, the Tucson monitor is more influenced by localized emissions from vehicles. The annual NO_2 concentrations at Tucson are therefore likely higher than would be expected at the more rural Coolidge location. Use of the Tucson data should therefore be a conservatively high representation of the upper bound of annual NO_2 concentrations experienced at Coolidge.

In addition, SRP has elected to use the ADEQ recommended 26.3 $\mu g/m^3$ 1-hour background NO_2 concentration from Alamo Lake (see the ADEQ Modeling Guidance at Section 7.1.4 as updated based upon the September 7, 2021 email from PCAQCD to SRP). The ADEQ recommends this value for areas where local anthropogenic NOx sources are negligible. As previously stated, the Coolidge location is in a rural area, about midway between Phoenix and Tucson, in an area devoid of any significant localized NOx industrial sources or heavy vehicular traffic. The Alamo Lake data should therefore adequately represent concentrations at the SRP location.

Data Quality

The existing ambient monitors were established and air quality data were collected as part of EPA's ambient air quality monitoring network. Federal regulations at 40 CFR Part 58, Appendix A, require that these data meet quality assurance (QA) requirements. The existing ambient air quality data also meet the data quality requirements of Section 2.4.2 of the Monitoring Guidelines. The QA requirements for monitoring criteria pollutants at PSD sites are very similar to the QA requirements for monitoring sites for NAAQS compliance. The proposed monitoring data meet the data quality criterion.

Currentness of Data

The Monitoring Guidelines suggest that air quality monitoring data used to meet PSD data requirements should be "collected in the 3-year period preceding the permit application."[6] All data presented herein, with the exception of PM10, are current and meet this criterion. The PM10 monitor in Coolidge ceased operation at the end of 2019. Therefore, the most recent three-year period covers the 2017-2019 timeframe. These data, however, should still be representative of the concentrations in the Coolidge area. This is the closest monitor to the SRP site and there has been no significant residential or industrial growth in the area since 2019 that would significantly influence current PM10 concentrations in the area. The population in Pinal County decreased by approximately 37,000 in 2020 as compared to 2019.[7] Additionally, review of a list of issued air permits in Pinal County in 2019 and 2020 indicates that there were only two minor permit revisions, one at the Cactus Landfill in Florence and one at the Frito-Lay facility in Casa Grande. The only significant permit revision occurred at the SRP Desert Basin facility which is in excess of 15 miles from Coolidge.

The Coolidge monitor sampling frequency of once every six days is consistent with 40 CFR § 58.12(e). Among monitoring sites satisfying the requirements of 40 CFR part 58, sampling frequency is not a pertinent factor listed in the Monitoring Guidelines as a factor to be considered in evaluating whether the proposed monitoring data are representative. The background values are shown in Table 1.

4.5 Receptor Data

Modeled receptors were placed in all areas considered as "ambient air" pursuant to 40 CFR §50.1(e) and §1-3-140 of the PCAQCD Regulations. Ambient air is defined as that portion of the atmosphere, external to buildings, to which the general public has access.

The receptor grid consisted of four Cartesian grids and receptors spaced at 25m intervals along the facility fenceline (or process area boundary) (Figure 6). The first Cartesian grid extended to approximately 3km from the fence in all directions.

Table 1. Ambient Background Values (2018-2020)

Pollutant	Average	Background Value ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Design Concentration	Monitor Name	Site ID
NO_2	Annual	15.5 (8.2ppb)	100 (53ppb)	Maximum of annual average from three years	Tucson	04-019-1028
	1-hr	26.3 (14.1ppb)	188 (100ppb)	Recently recommended ADEQ value.	Alamo Lake	Alamo Lake
CO	1-hr	1040 (0.91ppm)	40,000 (35ppm)	Highest concentration from past three years	Tucson	04-019-1028
	8-hr	812 (0.71ppm)	10,000 (9ppm)	Highest concentration from past three years		
Ozone	8-hr	137 (0.07 ppm)	137 (0.07 ppm)	Annual 4th high daily max 8-hr average from three years	Casa Grande	04-021-3003
PM2.5	Annual	7.19	12	Three year annual average	Casa Grande	04-021-3003
	24-hr	18.2	35	Average of the 98% 24hr values over three years		
PM10	24-hr	96.0	150	Three year average (2017-19) of 2nd high values.	Coolidge	04-021-3004

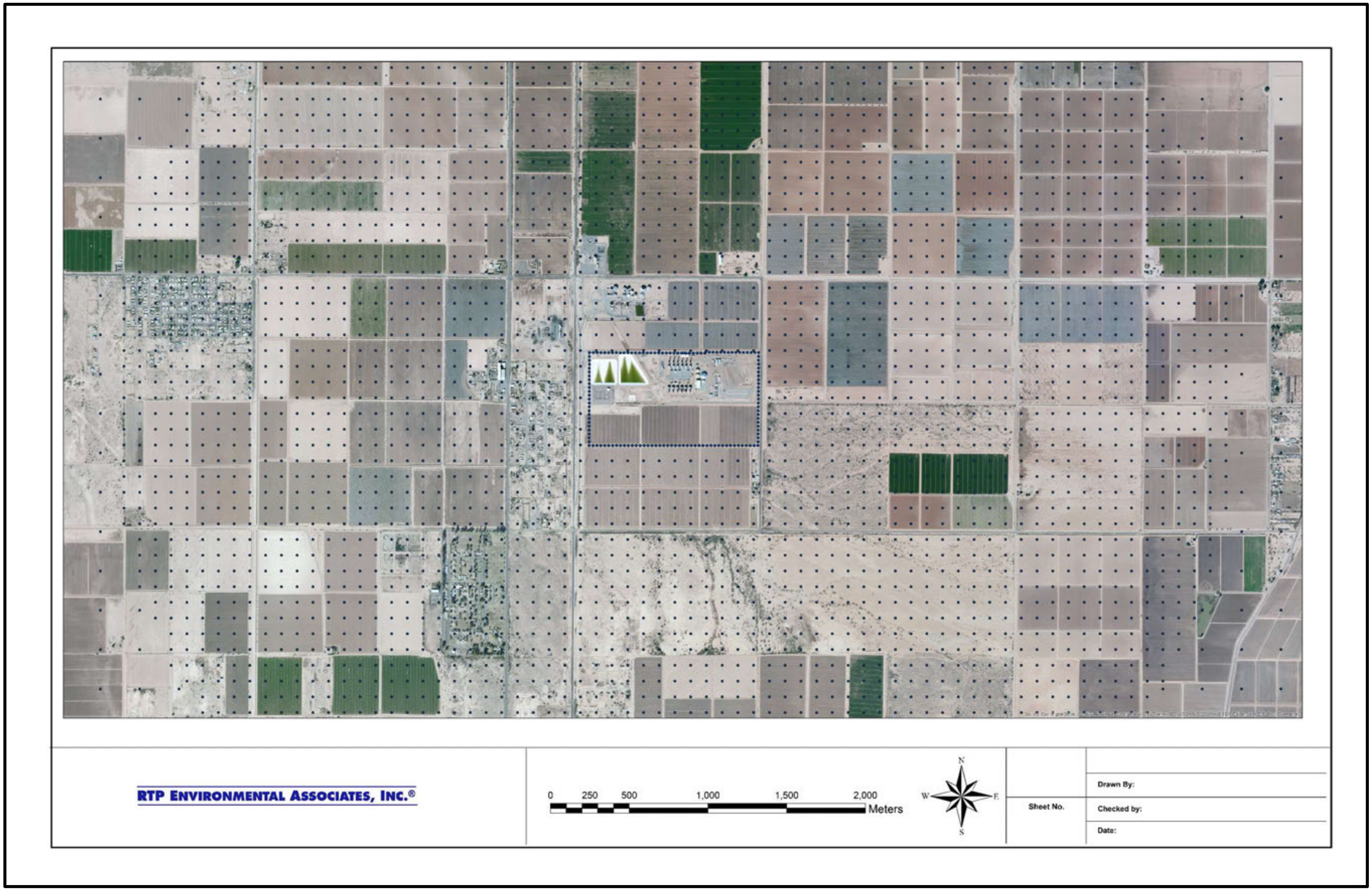


Figure 6. SRP Coolidge Near-field Receptor Grid

Receptors in this region were spaced at 100m intervals. The second Cartesian grid extended from 3km to 7.5km from the fenceline. Receptor spacing in this region was 250m. A third Cartesian grid was employed that extended from 7.5km to 10km from the fenceline. Receptor spacing in this region was 500m. A fourth grid extended from 10 to 25km with a spacing of 1000m. The receptor grid was designed such that maximum facility impacts fall within the 100m spacing of receptors. Maximum impacts outside of the 3km grid, as were seen in the mountainous regions to the northwest and southeast, were refined to 100m. Additionally, impacts in excess of 90% of a standard were resolved to 25m.

The SRP Coolidge facility is located in southern Arizona. There is terrain in the vicinity of the facility which exceeds stack top elevation. Receptor elevations and hill height

scale factors were calculated with AERMAP (18081). The elevation data were obtained from the USGS 1 arc second National Elevation Data (NED) obtained from the USGS. Locations were based upon a NAD83, UTM Zone 12 projection.

4.6 <u>Meteorological Data</u>

The 2014-2018, 5-year sequential hourly surface meteorological data collected at the Phoenix Sky Harbor International Airport (WBAN 23183) and upper air data from Tucson (WBAN 23160) were used in the analysis. These data were processed by ADEQ using AERMET version 19191. To address issues with model overprediction due to underprediction of the surface friction velocity (u*) during light wind, stable conditions, EPA integrated the ADJ_U* option into the AERMET processor. ADEQ used the ADJ_U* option in processing the data. ADEQ also employed 1-minute data using the AERMINUTE processor with a 0.5 m/sec wind speed threshold to minimize the number of calm wind conditions encountered when using Automated Surface Observing System (ASOS) data.

There are four criteria in the <u>Guideline</u> 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 Coolidge study area. Sky Harbor is located approximately 75km to the northwest of the SRP facility as shown in Figure 7. 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 at the SRP Coolidge site. The 2014-2018 windrose is provided in Figure 8.

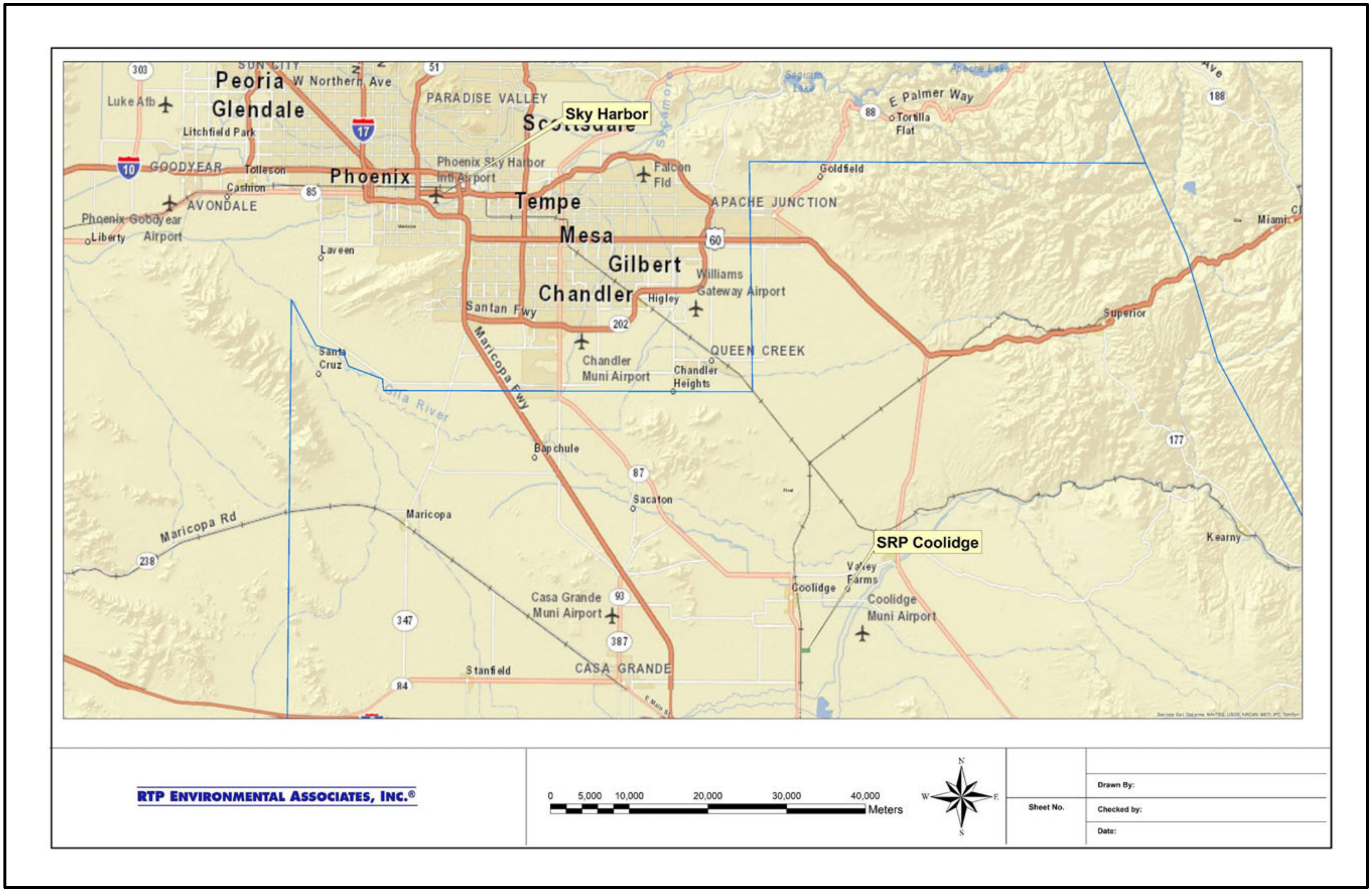
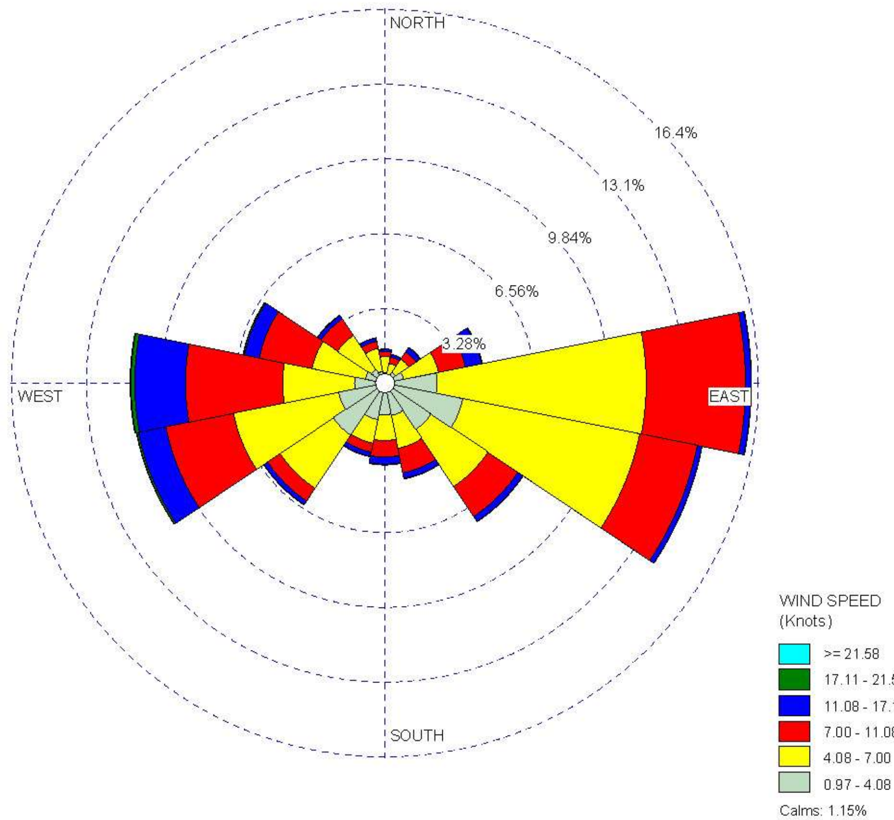


Figure 7. Location of the Phoenix Sky Harbor Airport Relative to the SRP Coolidge Facility

WIND ROSE PLOT:
Phoenix
2014-2018

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	Start Date: 1/1/2014 - 00:00 End Date: 12/31/2018 - 23:59	**RTP Environmental**	
		MODELER: **David Keen**	RTP ENVIRONMENTAL ASSOCIATES, INC.®
	CALM WINDS: **1.15%**	TOTAL COUNT: **43573 hrs.**	
	AVG. WIND SPEED: **6.27 Knots**	DATE: **3/31/2021**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8. Phoenix Sky Harbor Windrose (2014-2018)

5.0 MODELING METHODOLOGY

5.1 Pollutants Subject to Review

All criteria pollutants with emissions in excess of the minor NSR threshold were evaluated for NAAQS compliance. These pollutants include: NO_2, CO, PM2.5, PM10 and VOC (ozone).

5.2 Load/Operating Conditions and Facility Design

The turbine emission rates and stack parameters vary with the numerous combinations of operating load and ambient temperature. A load screening analysis was therefore performed to determine the operating conditions that result in the highest modeled impacts. Rather than model each of the potential combination of operating load and ambient temperature, a simplified, conservative analysis was performed by modeling the “worst-case” stack temperature and flow rate for multiple load conditions using the minimum value of flow and temperature at each load. For example, the turbine vendor provided stack gas conditions (i.e., gas release temperature and velocity) for five different ambient temperatures ranging from 10 to 102F for each of five operating scenarios (i.e., 100%, 75%, 50% load and start-up/shut-down). To simplify the analysis, the lowest gas exit temperature and velocity across the five different ambient conditions was modeled for each of the four operating scenarios. Because emissions are generally directly related to heat input rates, the emissions used for the four operating scenarios were be normalized based on the relative heat input at these four scenarions loads. Peak emission rates for the CTGs represent the maximum hour that includes startup for the first 30 minutes and normal operation for the remaining 30 minutes. Attachment A provides all load condition input values and the modeled parameters.

5.3 Significant Impact Analysis

The criteria pollutant air quality analysis, to demonstrate that the project will not cause or contribute to a NAAQS exceedance, was conducted in two phases: an initial or significant impact analysis, and a refined analysis if necessary. In the significant impacts analysis, the calculated maximum impacts were determined for each pollutant. These impacts were used to determine the net change in air quality resulting from the proposed project. Five years of Phoenix meteorological data were modeled. Maximum modeled concentrations were compared to the pollutant-specific significant impact levels for all pollutants and averaging times.

Pollutants with impacts that exceed the significant impact levels, as listed in Table 2, were evaluated for NAAQS compliance in a refined analysis

Pursuant to the ADEQ Modeling Guidelines, unlike methods used in NAAQS analyses for PSD permit applications, inclusion of regional or nearby sources under the minor NSR program is typically not required. However, SRP has conservatively included the adjacent Steel Girder, LLC/Stinger Bridge & Iron facility ("Stinger Welding") as a nearby source. The Stinger facility is located less than 0.5 km to the northwest of the SRP Coolidge facility. Given the proximity of the Stinger facility to the SRP Coolidge facility, it is possible that impacts from this source may not be adequately represented in the regional background concentrations. In the refined analysis, impacts from the SRP Coolidge facility and the nearby Stinger Welding facility were added to the regional background concentrations presented in Table 1. The resultant total concentrations were compared to the NAAQS.

The Western Emulsions facility is also located in close proximity to SRP (0.5km to the north). However, this facility only emits VOC and should not appreciably influence localized ozone concentrations in the vicinity of the SRP Coolidge facility.

5.4 Refined Analysis

Following the determination of significant impacts, a refined air quality analysis to determine compliance with the NAAQS was conducted. A refined analysis was conducted to determine compliance with the NAAQS only for pollutants modeled as having significant impacts in the initial analysis. The five-year Phoenix meteorological dataset is again used in this analysis.

Table 2. PSD Class II Significant Impact Levels

Pollutant	Averaging Time	PSD Class II Significant Impact Levels (μg/m³)[a]
PM2.5	24-hour	1.2
	Annual	0.2
PM10	25-hour	5
NO_2	1-hour	7.5[b]
	Annual	1.0
CO	1-hour	2,000
	8-hour	500
Ozone	8-hour	1 ppb

[a] Unless otherwise noted, significance levels are codified at § 3-1-030 of the PCAQCD Regulations.
[b] There is no 1-hr NO_2 significance level promulgated in the federal or PCAQCD regulations. An interim 1-hr NO_2 significance level of 4 ppb (7.5 μg/m³) will be used as the 1-hr NO_2 significance level.

The modeled design concentrations were added to the monitored values presented in Table 1 to assess compliance with the NAAQS. The form of the design concentration and the NAAQS are shown in Table 3.

5.5 NO_2 Analyses

Following EPA guidance, the NO_2 modeling analyses used the recommended three tier screening approach. Initially, Tier 1 was employed with the conservative assumption that 100% of the available NOx converts to NO_2. Since the NO_2 impacts under this assumption exceeded the SILs, the Tier 2 (Ambient Ratio Method, or ARM2) was employed with the EPA recommended minimum and maximum ambient NO2/NOx ratios of 0.5 and 0.9, respectively. Tier 3, which accounts for the chemical reactions that convert NOx to NO_2 in the presence of ozone, was not employed.

5.6 Secondary PM2.5 Analyses

On February 10, 2020, the EPA issued draft guidance for assessing ozone and fine particulate matter modeling.[8] The guidance addresses both primary and secondary PM2.5 impacts. Primary PM2.5 impacts refer to the impacts due to direct emissions of PM2.5. Secondary impacts refer to the PM2.5 impacts attributable to nitrates and sulfates formed due to precursor NO_2 and SO_2 emissions. The EPA outlines four cases

Table 3. Modeled Design Concentration and NAAQS

Pollutant	Averaging Time	Modeled Design Concentration (μg/m^3)	Ambient Air Quality Standards (μg/m^3)[a]	
			Primary	Secondary
PM2.5	24-hour	Highest of multi-year averages of the 98th percentile of the annual distribution of 24-hour concentrations predicted each year at each receptor	35	35
	Annual	Highest of multi-year averages of annual concentrations at each receptor	12	15
PM10	24-hour	Highest, sixth highest 24-hour modeled concentration that occurred at each receptor over that five-year period	150	
NO_2	1-hour	Highest of multi-year averages of the 98th percentile of the annual distribution of maximum daily 1-hour concentrations predicted each year at each receptor	188	--
	Annual	Highest modeled concentration over the entire receptor network	100	100
CO	1-hour	Highest, second highest concentrations over the entire receptor network for each year modeled	40,000	--
	8-hour	Highest, second highest concentrations over the entire receptor network for each year modeled	10,000	--

[a] 40 CFR part 50.

for assessing the primary and secondary PM2.5 impacts. The appropriate case to use depends on the magnitude of direct PM2.5 and precursor NO_2 and SO_2 emissions. Case 1 is applicable if the emissions increase of both direct PM2.5 and secondary NO_2 and SO_2 emissions are below the PSD significant emission rates (SER). Case 2 is applicable if the direct PM2.5 emissions increase is greater than the SER and the NOx and/or SO2 emissions increase is less than the respective SER. Case 3 is applicable if both the direct PM2.5 and NOx and/or SO_2 emissions are greater than the SER. Case 4 is applicable to direct PM2.5 emissions of less than the SER and NOx and/or SO_2 emissions in excess of the SER. While Case 2 is technically not applicable to the Coolidge expansion project because the PM2.5 emissions increase is less than the SER, SRP modeled the direct PM2.5 emissions and compared the results to the significant impact levels. Secondary PM2.5 impacts were not assessed since precursor NO_2 and SO_2 emissions are less than the SER.

5.7 Ozone Analysis

Currently, there are no regulatory photochemical models available to evaluate smaller spatial scales or single-source impacts on ozone concentrations. Since ozone is formed from precursor pollutants, assessment of ambient ozone impacts is typically conducted on a regional basis using resource-intensive models, such as the EPA's Community Multiscale Air Quality (CMAQ) model. However, sources subject to PSD review are required to conduct a source impact analysis and demonstrate that a proposed source will not cause or contribute to a violation of any NAAQS or applicable increment. Qualitative ozone analyses typically have been performed in recent PSD applications to evaluate whether ozone precursor emissions (NO_X and VOC) will significantly impact regional ozone formation.

While VOC and NOx emissions increases associated with the project are less than the PSD SERs, the project's ozone precursor emissions were evaluated under the EPA's Modeled Emission Rates for Precursors (MERPs) guidance to demonstrate that the Project will not result in quantifiable ozone formation. SRP has evaluated Source No.

4007 from Gila County under the EPA's ozone MERPs guidance. Since the proposed VOC and NOx emissions increase from the SRP project are less than the MERP values for source 4007, SRP concludes that the proposed Coolidge expansion project will not cause or contribute to a violation of the NAAQS for ozone. No additional ozone impacts analysis was therefore conducted.

5.8 Modeling for HAPs Sources – Learning Sites Policy

ADEQ has established the Learning Sites Policy to ensure that children at learning sites are protected from criteria air pollutants as well as 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 air toxics. The closest schools to the SRP Coolidge facility are the Mary C O'Brien Elementary School and the West Elementary School. Both schools are located in excess of 4 miles from the SRP Coolidge facility. Therefore, no additional modeling was conducted pursuant to the Learning Sites Policy.

6.0 MODEL RESULTS

Attachment B to this report provides the model summary output. AERMOD input and output files, including the BPIP-PRIME files, are provided electronically.

6.1 Load Analysis Results

The results of the load analysis can be found in Attachment B. The startup load condition was found to cause the highest impacts for all turbines for all averaging periods. The emissions and stack parameters associated with this load condition were therefore conservatively used in the remainder of the analysis. The startup emissions were not excluded from the significant impact or 1-hr NO_2 NAAQS demonstration.

6.2 Significant Impact Analysis Results

The project resulted in significant impacts for PM10, PM2.5, and NO_2 (Table 4). Based upon the results of the significant impacts analysis, a cumulative analysis was conducted to assess compliance with the NAAQS.

Table 4. Significant Impact Analysis Results

Pollutant	Avg Period	Maximum Modeled Impact - (μg/m^3)	PSD Significant Impact Level (μg/m^3)	Maximum Distance to a Significant Impact (km)
NO_2	1-hr	71.3	7.5	25
	Annual	2.25	1.0	1.4
CO	1-hr	116	2,000	NA
	8-hr	45.8	500	NA
PM2.5	24-hr	4.37	1.2	21.1
	Annual	0.85	0.20	15.9
PM10	24-hr	5.62	5	0.79
SO_2	1-hr	2.40	7.8	NA
	3-hr	1.49	25	NA

NA- not applicable. Pollutant impact less than the SIL.

6.3 NAAQS Analysis Results

Following the determination of significant impacts, an analysis was conducted to assess compliance with the NO_2, PM10 and PM2.5 NAAQS. The adjacent Stinger Welding facility was included in the model and background concentrations were added to the model results to assess compliance. Evaluation of compliance with the 1-hr NO_2 NAAQS was based on the 98^{th} percentile of the annual distribution of daily maximum 1-hour concentrations. Evaluation of compliance with the 24-hr PM2.5 NAAQS was based on the 98^{th} percentile of the annual distribution of maximum 24-hour concentrations. Compliance with the PM10 24-hr standard was based upon the sixth highest value over the five-year meteorological period. Annual PM2.5 NAAQS compliance was evaluated based upon the average of the five-year modeled annual concentrations.

The results of the NAAQS analysis are presented in Table 5. As can be seen, the model demonstrates compliance. Summary model output can be found in Attachment B.

Table 5. NAAQS Analysis Results

Pollutant	Averaging Period	Modeled Concentration (μg/m³)	Background Concentration (μg/m³)	Total Concentration (μg/m³)	Standard (μg/m³)
NO_2	1-hour	104	26.3	130	188
	Annual	3.70	15.5	19.2	100
PM2.5	24-hour	3.69	18.2	21.9	35
	Annual	1.78	7.19	8.97	12
PM10	24-hour	41.1	96.0	137	150

ATTACHMENT A
MODEL INPUT DATA

Load Screen Analysis Input for GE LM6000PC Aeroderivative Combustion Turbines with SCR and Oxidation Catalyst

1. Stack Conditions

Simple Cycle Units			Ambient	Inlet		Stack Temp (F)			Stack Velocity (ft/s)		
Condition	Category	Model	Temp (F)	Conditioning	Load -->	100%	75%	50%	100%	75%	50%
GEA-1	Aero	LMS6000PC	10	No		767	712	656	112.00	96.00	80.00
GEA-2	Aero	LMS6000PC	59	Yes		780	777	745	120.00	97.00	82.00
GEA-3	Aero	LMS6000PC	59	No		780	780	750	109.00	91.00	76.00
GEA-4	Aero	LMS6000PC	102	Yes		780	780	780	116.00	96.00	79.00
GEA-5	Aero	LMS6000PC	102	No		780	780	780	87.00	76.00	67.00

Startup represents average for the duration of unit startup.

2. Emission Rates

	Ambient	Inlet		PM(f+c) (lb/hr)				NOx (lb/hr)				CO (lb/hr)			
Condition	Temp (F)	Conditioning	Load -->	100%	75%	50%	Startup	100%	75%	50%	Startup	100%	75%	50%	Shutdown
GEA-1	10	No		4.18	4.14	4.11	6.19	4.30	3.40	2.60	16.45	7.30	5.80	4.40	22.81
GEA-2	59	Yes		4.19	4.15	4.11	6.20	4.40	3.50	2.60	16.50	7.60	6.00	4.50	23.06
GEA-3	59	No		4.16	4.13	4.10	6.18	3.80	3.10	2.40	16.20	6.50	5.30	4.10	22.13
GEA-4	102	Yes		4.17	4.14	4.11	6.19	4.10	3.30	2.50	16.35	7.00	5.60	4.20	22.55
GEA-5	102	No		4.11	4.00	4.08	6.16	2.70	2.30	1.90	15.65	4.60	3.90	3.20	20.51

For startup PM and NOx, use the GE information for startup plus 30 min of normal operation max load hourly emissions for that temperature condition.
For CO shutdown was worst case. Used 51 min of normal CO peak hourly emissions plust shutdown emission rate.

condition	emission ratios relative to 100% load										
GEA-1	0.99	0.98	1.48	1.00	0.79	0.60	3.83	1.00	0.79	0.60	3.12
GEA-2	0.99	0.98	1.48	2.00	0.80	0.59	3.75	2.00	0.79	0.59	3.03
GEA-3	0.99	0.99	1.49	3.00	0.82	0.63	4.26	3.00	0.82	0.63	3.40
GEA-4	0.99	0.99	1.48	4.00	0.80	0.61	3.99	4.00	0.80	0.60	3.22
GEA-5	0.97	0.99	1.50	5.00	0.85	0.70	5.80	5.00	0.85	0.70	4.46
max	0.99	0.99	1.50	1.00	0.85	0.70	5.80	1.00	0.85	0.70	4.46
min	0.97	0.98	1.48	1.00	0.79	0.59	3.75	1.00	0.79	0.59	3.03
avg	0.99	0.99	1.49	1.00	0.81	0.63	4.32	1.00	0.81	0.62	3.45

Rather than model each of the 20 combinations of stack and ambient temperatures and loads for each turbine load condition, a simplified yet conservative analysis was performed by modeling “worst-case” stack temperatures and flow rates over ambient temperatures for each load. The the minimum stack gas temperature and velocity and maximum emission rate across the ambient conditions were modeled for each load. Because emissions are directly related to heat input rates, the emissions used for the three load scenarios were normalized to values of 1.0, 0.85, 0.70, and 5.8 based on the relative heat input at these four loads (100%, 75%, 50% and startup).

Modeled Load Parameters

Source ID	Source Description	Temp. (F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	Unit (lb/hr)
GE_100	GE LM6000 100% Load	767	87.0	11	1.00
GE_75	GE LM6000 75% Load	712	76.0	11	0.85
GE_50	GE LM6000 50% Load	656	67.0	11	0.70
GE_SU	GE LM6000 Startup	656	67.0	11	5.80

SRP Coolidge Turbine Load/Ambient Temp. Screening Model Input (NAD83, Zone 12)
Updated (5-27-21)

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temp. (F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	Unit (lb/hr)
GE_100	GE LM6000 100% Load	453173.75	3641882.99	1444.5	85	767.0	87.0	11	1.00
GE_75	GE LM6000 75% Load	453173.75	3641882.99	1444.5	85	712.0	76.0	11	0.85
GE_50	GE LM6000 50% Load	453173.75	3641882.99	1444.5	85	656.0	67.0	11	0.70
GE_SU	GE LM6000 Startup	453173.75	3641882.99	1444.5	85	656.0	67.0	11	5.80

Load conditions are reflective of worst case (lowest) temperature and velocity and worst case emission rate (highest) for each turbine across all ambient conditions.

SRP Coolidge Model Input (NAD83, Zone 12)
Updated (7-26-21)

Source ID		Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temp. (F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	NO2 (lb/hr)	NOx (lb/hr)	PM2.5 (lb/hr)	PM10 (lb/hr)	CO (lb/hr)	SO2 (lb/hr)	SOx (lb/hr)
GE1	DEFAULT	Existing GE LM6000 Turbine 1	452862.09	3642324.87	1442.5	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE2	DEFAULT	Existing GE LM6000 Turbine 2	452888.79	3642324.58	1442.6	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE3	DEFAULT	Existing GE LM6000 Turbine 3	452915.97	3642324.44	1442.6	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE4	DEFAULT	Existing GE LM6000 Turbine 4	452942.88	3642324.44	1442.8	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE5	DEFAULT	Existing GE LM6000 Turbine 5	452969.78	3642324.58	1442.9	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE6	DEFAULT	Existing GE LM6000 Turbine 6	452996.68	3642324.30	1443.2	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE7	DEFAULT	Existing GE LM6000 Turbine 7	452861.28	3642133.99	1443.8	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE8	DEFAULT	Existing GE LM6000 Turbine 8	452888.17	3642133.99	1443.9	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE9	DEFAULT	Existing GE LM6000 Turbine 9	452915.06	3642133.99	1444.0	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE10	DEFAULT	Existing GE LM6000 Turbine 10	452942.53	3642133.99	1444.3	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE11	DEFAULT	Existing GE LM6000 Turbine 11	452968.83	3642133.99	1444.5	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE12	DEFAULT	Existing GE LM6000 Turbine 12	452995.72	3642133.41	1444.7	85.0	853.4	110.0	10.5	33.0	33.0	7.0	7.0	63.0	7.0	7.0
GE13	DEFAULT	Proposed GE LM6000 Turbine 1	453046.11	3641911.65	1446.0	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE14	DEFAULT	Proposed GE LM6000 Turbine 2	453075.57	3641911.00	1446.1	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE15	DEFAULT	Proposed GE LM6000 Turbine 3	453105.74	3641910.65	1446.3	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE16	DEFAULT	Proposed GE LM6000 Turbine 4	453135.17	3641909.87	1446.4	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE17	DEFAULT	Proposed GE LM6000 Turbine 5	453174.32	3641908.93	1446.7	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE18	DEFAULT	Proposed GE LM6000 Turbine 6	453203.14	3641909.50	1447.0	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE19	DEFAULT	Proposed GE LM6000 Turbine 7	453233.68	3641908.64	1447.4	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE20	DEFAULT	Proposed GE LM6000 Turbine 8	453263.08	3641908.35	1447.8	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE21	DEFAULT	Proposed GE LM6000 Turbine 9	453045.52	3641885.01	1446.1	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE22	DEFAULT	Proposed GE LM6000 Turbine 10	453074.91	3641884.14	1446.3	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE23	DEFAULT	Proposed GE LM6000 Turbine 11	453105.22	3641884.02	1446.4	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE24	DEFAULT	Proposed GE LM6000 Turbine 12	453134.84	3641883.57	1446.5	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE25	DEFAULT	Proposed GE LM6000 Turbine 13	453173.75	3641882.99	1446.9	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE26	DEFAULT	Proposed GE LM6000 Turbine 14	453202.85	3641882.41	1447.3	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE27	DEFAULT	Proposed GE LM6000 Turbine 15	453233.40	3641881.84	1447.7	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
GE28	DEFAULT	Proposed GE LM6000 Turbine 16	453262.90	3641881.46	1448.1	85.0	656.0	67.0	11.0	16.5	16.5	6.2	6.2	23.1	0.5	0.5
CT1_CELL1	DEFAULT	Proposed Cooling Tower	452784.29	3642198.70	1443.1	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT1_CELL2	DEFAULT	Proposed Cooling Tower	452800.48	3642198.57	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT1_CELL3	DEFAULT	Proposed Cooling Tower	452792.13	3642198.32	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT1_CELL4	DEFAULT	Proposed Cooling Tower	452806.91	3642198.32	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT1_CELL5	DEFAULT	Proposed Cooling Tower	452814.49	3642198.45	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT1_CELL6	DEFAULT	Proposed Cooling Tower	452821.43	3642198.06	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT2_CELL1	DEFAULT	Proposed Cooling Tower	452783.87	3642181.46	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT2_CELL2	DEFAULT	Proposed Cooling Tower	452791.82	3642181.27	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT2_CELL3	DEFAULT	Proposed Cooling Tower	452800.49	3642181.21	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT2_CELL4	DEFAULT	Proposed Cooling Tower	452806.76	3642181.08	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0

Source ID		Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temp. (F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	NO2 (lb/hr)	NOx (lb/hr)	PM2.5 (lb/hr)	PM10 (lb/hr)	CO (lb/hr)	SO2 (lb/hr)	SOx (lb/hr)
CT2_CELL5	DEFAULT	Proposed Cooling Tower	452814.66	3642180.82	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT2_CELL6	DEFAULT	Proposed Cooling Tower	452821.64	3642180.62	1443.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT3_CELL1	DEFAULT	Proposed Cooling Tower	453079.27	3642293.06	1443.9	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT3_CELL2	DEFAULT	Proposed Cooling Tower	453092.41	3642293.25	1444.0	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT3_CELL3	DEFAULT	Proposed Cooling Tower	453086.41	3642292.87	1443.9	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT3_CELL4	DEFAULT	Proposed Cooling Tower	453115.32	3642292.87	1444.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT3_CELL5	DEFAULT	Proposed Cooling Tower	453107.06	3642292.69	1444.1	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT3_CELL6	DEFAULT	Proposed Cooling Tower	453100.30	3642292.31	1444.0	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT4_CELL1	DEFAULT	Proposed Cooling Tower	452989.35	3641883.61	1449.0	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT4_CELL2	DEFAULT	Proposed Cooling Tower	453000.49	3641883.77	1449.5	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT4_CELL3	DEFAULT	Proposed Cooling Tower	453012.39	3641883.77	1449.3	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT4_CELL4	DEFAULT	Proposed Cooling Tower	452989.50	3641874.43	1450.1	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT4_CELL5	DEFAULT	Proposed Cooling Tower	453000.64	3641874.18	1449.9	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT4_CELL6	DEFAULT	Proposed Cooling Tower	453012.39	3641874.49	1449.7	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT5_CELL1	DEFAULT	Proposed Cooling Tower	452989.35	3641858.61	1449.4	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT5_CELL2	DEFAULT	Proposed Cooling Tower	453000.49	3641858.77	1449.9	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT5_CELL3	DEFAULT	Proposed Cooling Tower	453012.39	3641858.77	1449.7	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT5_CELL4	DEFAULT	Proposed Cooling Tower	452989.50	3641849.43	1450.4	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT5_CELL5	DEFAULT	Proposed Cooling Tower	453000.64	3641849.18	1450.3	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT5_CELL6	DEFAULT	Proposed Cooling Tower	453012.39	3641849.49	1450.1	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT6_CELL1	DEFAULT	Proposed Cooling Tower	452989.35	3641833.61	1449.6	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT6_CELL2	DEFAULT	Proposed Cooling Tower	453000.49	3641833.77	1450.0	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT6_CELL3	DEFAULT	Proposed Cooling Tower	453012.39	3641833.77	1449.8	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT6_CELL4	DEFAULT	Proposed Cooling Tower	452989.50	3641824.43	1450.5	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT6_CELL5	DEFAULT	Proposed Cooling Tower	453000.64	3641824.18	1450.3	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT6_CELL6	DEFAULT	Proposed Cooling Tower	453012.39	3641824.49	1450.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT7_CELL1	DEFAULT	Proposed Cooling Tower	452989.35	3641808.61	1449.9	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT7_CELL2	DEFAULT	Proposed Cooling Tower	453000.49	3641808.77	1450.2	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT7_CELL3	DEFAULT	Proposed Cooling Tower	453012.39	3641808.77	1450.0	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT7_CELL4	DEFAULT	Proposed Cooling Tower	452989.50	3641799.43	1450.6	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT7_CELL5	DEFAULT	Proposed Cooling Tower	453000.64	3641799.18	1450.4	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0
CT7_CELL6	DEFAULT	Proposed Cooling Tower	453012.39	3641799.49	1450.3	43.1	89.0	7.0	13.5	0.0	0.0	3.33E-05	6.67E-03	0.0	0.0	0.0

SRP Coolidge Off-Site Source Input Data - (NAD83, Zone 12)

Model Source No.	Source ID	Source Description	Easting (X)	Northing (Y)	Base Elevation (ft)	Release Height (ft)	Horizontal Dimension - Sigma Y (ft)	Vertical Dimension - Sigma Z (ft)	Emissions (lb/hr)						
									NO2 (lb/hr)	NOx (lb/hr)	PM2.5 (lb/hr)	PM10 (lb/hr)	CO (lb/hr)	SO2 (lb/hr)	SOx (lb/hr)
71	STING	Stinger Welding	452145.00	3642683.00	1440.2	35.0	85.4	32.6	1.44E-01	1.44E-01	1.39E-01	1.39E+00	3.20E-02	8.00E-03	8.00E-03

Stinger Welding is a minor source. Short term emission rates were calculated from actual emissions from 2018-19. 2500 hr/yr operation was assumed.

Annual emissions were not provided for PM2.5. PM2.5 emissions were assumed equal to 10% of PM10 emissions based upon AP-41, Table 13.2.6-1.

Stinger Welding Volume Source Parameter Calculation

		Source Dimensions					Initial Dispersion Coefficients		
Source ID	Source Description	Length (ft)	Width (ft)	Square Root of Area (ft)	Structure Height/Vertical Dimension (ft)	Release Height (ft)	Initial Horizontal Dimension s_Y (ft)	Initial Vertical Dimension s_Z (ft)	Note
STING	Stinger Welding	600.00	225.00	367.42	70.00	35.00	85.45	32.56	Elevated source on or adjacent to building

Sigma Y values calculated as the square root of the area, or average length of side, divided by 4.3 (Table 3-1 of AERMOD Manual for Single Volume Source).

Sigma Z values for surface based sources calculated as the initial vertical dimension of source divided by 2.15 (Table 3-1 of AERMOD Manual for Elevated Source Not on or Adjacent to Building).

Sigma Z values for elevated sources on or adjacent to a building calculated as the building height divided by 2.15 (Table 3-1 of AERMOD Manual for Elevated Source on or Adjacent to Building).

Sigma Z values for elevated sources not on or adjacent to a building calculated as the initial vertical dimension of source divided by 4.3 (Table 3-1 of AERMOD Manual for Elevated Source Not on or Adjacent to Building).

Release height equal to center of volume, or 1/2 vertical dimension.

ATTACHMENT B
MODEL RESULTS

SRP Coolidge Load Analysis Results (8-10-21)

Model	File	Pollutant	Average	Group	Rank	Conc/Dep	East (X)	North (Y)	Elev	Hill	Flag	Time	Met File	Sources	Groups	Receptors
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	1-HR	GE_100	1ST	0.26639	465264.13	3635389.44	587.87	784.3	0	17110923	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	1-HR	GE_100	1ST	0.2557	466364.13	3636089.44	593.36	784.3	0	15112321	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	1-HR	GE_100	1ST	0.25465	438372.54	3646971.38	583.36	688.35	0	14120518	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	1-HR	GE_100	1ST	0.25134	438272.54	3650071.38	594.49	836.73	0	16012201	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	1-HR	GE_100	1ST	0.24083	438672.54	3647971.38	574.36	688.35	0	18022106	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	1-HR	GE_50	1ST	0.22092	438472.54	3646871.38	566.28	688.35	0	14120518	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	1-HR	GE_50	1ST	0.22074	466364.13	3636189.44	579.47	784.3	0	17061323	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	1-HR	GE_50	1ST	0.21871	438472.54	3646871.38	566.28	688.35	0	15110804	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	1-HR	GE_50	1ST	0.21846	438672.54	3647971.38	574.36	688.35	0	18022106	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	1-HR	GE_50	1ST	0.21736	453800	3641900	443.74	443.74	0	16031202	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	1-HR	GE_75	1ST	0.24761	465264.13	3635489.44	584.15	784.3	0	17110923	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	1-HR	GE_75	1ST	0.23826	438372.54	3646971.38	583.36	688.35	0	14120518	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	1-HR	GE_75	1ST	0.23742	438672.54	3647971.38	574.36	688.35	0	18022106	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	1-HR	GE_75	1ST	0.23705	464964.13	3631689.44	580.38	733.94	0	15012724	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	1-HR	GE_75	1ST	0.22793	437172.54	3650371.38	584.61	836.73	0	16012201	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	1-HR	GE_SU	1ST	1.83046	438472.54	3646871.38	566.28	688.35	0	14120518	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	1-HR	GE_SU	1ST	1.82903	466364.13	3636189.44	579.47	784.3	0	17061323	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	1-HR	GE_SU	1ST	1.81214	438472.54	3646871.38	566.28	688.35	0	15110804	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	1-HR	GE_SU	1ST	1.81011	438672.54	3647971.38	574.36	688.35	0	18022106	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	1-HR	GE_SU	1ST	1.80096	453800	3641900	443.74	443.74	0	16031202	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	24-HR	GE_100	1ST	0.04146	453700	3641900	443.46	443.46	0	18071924	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	24-HR	GE_100	1ST	0.04086	453700	3642000	443.5	443.5	0	17042524	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	24-HR	GE_100	1ST	0.0408	453600	3642200	443.07	443.07	0	16042524	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	24-HR	GE_100	1ST	0.03853	452679.24	3641720.18	440.45	440.45	0	14051424	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	24-HR	GE_100	1ST	0.03675	453700	3641900	443.46	443.46	0	15070224	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	24-HR	GE_50	1ST	0.03852	453600	3641900	443.08	443.08	0	18071924	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	24-HR	GE_50	1ST	0.03711	453600	3642200	443.07	443.07	0	16042524	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	24-HR	GE_50	1ST	0.03701	453700	3642000	443.5	443.5	0	17042524	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	24-HR	GE_50	1ST	0.03453	452679.24	3641720.18	440.45	440.45	0	14051424	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	24-HR	GE_50	1ST	0.03412	453600	3641800	443.07	443.07	0	15062624	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	24-HR	GE_75	1ST	0.04073	453600	3641900	443.08	443.08	0	18071924	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	24-HR	GE_75	1ST	0.03968	453700	3642000	443.5	443.5	0	17042524	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	24-HR	GE_75	1ST	0.03963	453600	3642200	443.07	443.07	0	16042524	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	24-HR	GE_75	1ST	0.03723	452679.24	3641720.18	440.45	440.45	0	14051424	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	24-HR	GE_75	1ST	0.03585	453600	3641800	443.07	443.07	0	15062624	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	24-HR	GE_SU	1ST	0.31918	453600	3641900	443.08	443.08	0	18071924	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	24-HR	GE_SU	1ST	0.30751	453600	3642200	443.07	443.07	0	16042524	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	24-HR	GE_SU	1ST	0.30662	453700	3642000	443.5	443.5	0	17042524	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	24-HR	GE_SU	1ST	0.28614	452679.24	3641720.18	440.45	440.45	0	14051424	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	24-HR	GE_SU	1ST	0.28269	453600	3641800	443.07	443.07	0	15062624	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	3-HR	GE_100	1ST	0.15189	438272.54	3650071.38	594.49	836.73	0	16012203	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	3-HR	GE_100	1ST	0.13836	453700	3641800	443.46	443.46	0	18072612	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	3-HR	GE_100	1ST	0.13806	452600	3641700	440.36	440.36	0	15030612	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	3-HR	GE_100	1ST	0.13752	437072.54	3650371.38	586.39	836.73	0	14103024	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	3-HR	GE_100	1ST	0.12979	452700	3641600	440.66	440.66	0	17030215	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	3-HR	GE_50	1ST	0.13056	438272.54	3649671.38	566.65	836.73	0	16012203	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	3-HR	GE_50	1ST	0.12573	438572.54	3647271.38	560.49	688.35	0	15112624	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	3-HR	GE_50	1ST	0.12264	452700	3641700	440.51	440.51	0	18101912	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	3-HR	GE_50	1ST	0.12219	438172.54	3649571.38	565.77	836.73	0	14103024	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	3-HR	GE_50	1ST	0.11819	452679.24	3641720.18	440.45	440.45	0	17121012	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	3-HR	GE_75	1ST	0.1423	438272.54	3649671.38	566.65	836.73	0	16012203	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	3-HR	GE_75	1ST	0.13397	438572.54	3647271.38	560.49	688.35	0	15112624	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	3-HR	GE_75	1ST	0.13323	453700	3641800	443.46	443.46	0	18072612	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	3-HR	GE_75	1ST	0.12912	438172.54	3649571.38	565.77	836.73	0	14103024	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	3-HR	GE_75	1ST	0.12514	452679.24	3641720.18	440.45	440.45	0	17121012	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	3-HR	GE_SU	1ST	1.08178	438272.54	3649671.38	566.65	836.73	0	16012203	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	3-HR	GE_SU	1ST	1.04178	438572.54	3647271.38	560.49	688.35	0	15112624	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	3-HR	GE_SU	1ST	1.01613	452700	3641700	440.51	440.51	0	18101912	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	3-HR	GE_SU	1ST	1.01247	438172.54	3649571.38	565.77	836.73	0	14103024	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	3-HR	GE_SU	1ST	0.97929	452679.24	3641720.18	440.45	440.45	0	17121012	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	8-HR	GE_100	1ST	0.10218	453700	3641800	443.46	443.46	0	18072616	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	8-HR	GE_100	1ST	0.10158	452700	3641700	440.51	440.51	0	15030616	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	8-HR	GE_100	1ST	0.10123	453600	3642200	443.07	443.07	0	16042516	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	8-HR	GE_100	1ST	0.09668	453700	3642000	443.5	443.5	0	17042516	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	8-HR	GE_100	1ST	0.08904	452654.27	3641720.46	440.4	440.4	0	14051416	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	8-HR	GE_50	1ST	0.09302	452700	3641700	440.51	440.51	0	18012916	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	8-HR	GE_50	1ST	0.091	452700	3641700	440.51	440.51	0	15030616	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	8-HR	GE_50	1ST	0.09042	453600	3642200	443.07	443.07	0	16042516	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	8-HR	GE_50	1ST	0.08636	453700	3642000	443.5	443.5	0	17042516	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	8-HR	GE_50	1ST	0.07762	452679.24	3641720.18	440.45	440.45	0	14051416	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	8-HR	GE_75	1ST	0.0989	453700	3641800	443.46	443.46	0	18072616	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	8-HR	GE_75	1ST	0.09824	452700	3641700	440.51	440.51	0	15030616	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	8-HR	GE_75	1ST	0.09752	453600	3642200	443.07	443.07	0	16042516	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	8-HR	GE_75	1ST	0.09326	453700	3642000	443.5	443.5	0	17042516	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	8-HR	GE_75	1ST	0.0846	452679.24	3641720.18	440.45	440.45	0	14051416	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	8-HR	GE_SU	1ST	0.77077	452700	3641700	440.51	440.51	0	18012916	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	8-HR	GE_SU	1ST	0.75403	452700	3641700	440.51	440.51	0	15030616	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	8-HR	GE_SU	1ST	0.7492	453600	3642200	443.07	443.07	0	16042516	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	8-HR	GE_SU	1ST	0.71555	453700	3642000	443.5	443.5	0	17042516	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	8-HR	GE_SU	1ST	0.64313	452679.24	3641720.18	440.45	440.45	0	14051416	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	ANNUAL	GE_100	1ST	0.00745	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	ANNUAL	GE_100	1ST	0.00663	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	ANNUAL	GE_100	1ST	0.00643	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	ANNUAL	GE_100	1ST	0.0063	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	ANNUAL	GE_100	1ST	0.00624	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	ANNUAL	GE_50	1ST	0.00683	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	ANNUAL	GE_50	1ST	0.0061	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990

AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	ANNUAL	GE_50	1ST	0.00596	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	ANNUAL	GE_50	1ST	0.0059	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	ANNUAL	GE_50	1ST	0.00578	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	ANNUAL	GE_75	1ST	0.00727	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	ANNUAL	GE_75	1ST	0.00647	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	ANNUAL	GE_75	1ST	0.0063	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	ANNUAL	GE_75	1ST	0.00621	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	ANNUAL	GE_75	1ST	0.00611	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2017_Unit.SUM	UNIT	ANNUAL	GE_SU	1ST	0.0566	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2016_Unit.SUM	UNIT	ANNUAL	GE_SU	1ST	0.05052	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2014_Unit.SUM	UNIT	ANNUAL	GE_SU	1ST	0.04936	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2018_Unit.SUM	UNIT	ANNUAL	GE_SU	1ST	0.04889	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990
AERMOD 21112	Coolidge Load_2015_Unit.SUM	UNIT	ANNUAL	GE_SU	1ST	0.04788	453600	3641900	443.08	443.08	0	1 YEARS	MET	4	4	16990

SRP Coolidge Load Analysis Results (8-10-21)

Load Level	Average	Group	Rank	Conc
100%	1-HR	GE_100	1ST	0.2664
75%	1-HR	GE_75	1ST	0.2476
50%	1-HR	GE_50	1ST	0.2209
Startup	1-HR	GE_SU	1ST	**1.8305**
100%	3-HR	GE_100	1ST	0.1519
75%	3-HR	GE_75	1ST	0.1423
50%	3-HR	GE_50	1ST	0.1306
Startup	3-HR	GE_SU	1ST	**1.0818**
100%	8-HR	GE_100	1ST	0.1022
75%	8-HR	GE_75	1ST	0.0989
50%	8-HR	GE_50	1ST	0.0930
Startup	8-HR	GE_SU	1ST	**0.7708**
100%	24-HR	GE_100	1ST	0.0415
75%	24-HR	GE_75	1ST	0.0407
50%	24-HR	GE_50	1ST	0.0385
Startup	24-HR	GE_SU	1ST	**0.3192**
100%	Annual	GE_100	1ST	0.0075
75%	Annual	GE_75	1ST	0.0073
50%	Annual	GE_50	1ST	0.0068
Startup	Annual	GE_SU	1ST	**0.0566**

The Start up/Shut down condition was determined to cause the worst-case impacts for each turbine type.

SRP Coolidge Significant Impact Analysis Results (8-11-21)

Model	File	Pollutant	Average	Group	Rank	Conc/Dep	East (X)	North (Y)	Elev	Hill	Flag	Time	Met File	Sources	Groups	Receptors
AERMOD 21112	Coolidge SIL_2014_CO.SUM	CO	1-HR	ALL	1ST	116.09323	438472.54	3646871.38	566.28	688.35	0	14120518	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2017_CO.SUM	CO	1-HR	ALL	1ST	115.95658	466364.13	3636189.44	579.47	784.3	0	17061323	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2018_CO.SUM	CO	1-HR	ALL	1ST	115.33147	438672.54	3647971.38	574.36	688.35	0	18022106	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2015_CO.SUM	CO	1-HR	ALL	1ST	115.0185	438472.54	3646871.38	566.28	688.35	0	15110804	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2016_CO.SUM	CO	1-HR	ALL	1ST	108.88881	438172.54	3650071.38	570.56	836.73	0	16012201	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2018_CO.SUM	CO	8-HR	ALL	1ST	45.79764	452600	3641700	440.36	440.36	0	18012916	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2015_CO.SUM	CO	8-HR	ALL	1ST	45.31919	452654.27	3641720.46	440.4	440.4	0	15030616	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2017_CO.SUM	CO	8-HR	ALL	1ST	43.85941	453600	3642000	443.26	443.26	0	17042516	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2016_CO.SUM	CO	8-HR	ALL	1ST	43.50053	453600	3642200	443.07	443.07	0	16042516	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2014_CO.SUM	CO	8-HR	ALL	1ST	38.25696	452604.33	3641721	440.35	440.35	0	14051416	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2014-2018_NO2.SUM	NO2	1ST-HIGHEST MAX DAILY 1-HR	ALL	1ST	71.26288	438672.54	3647971.38	574.36	688.35	0	5 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2017_NOX.SUM	NO2	ANNUAL	ALL	1ST	2.25251	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2016_NOX.SUM	NO2	ANNUAL	ALL	1ST	2.02127	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2014_NOX.SUM	NO2	ANNUAL	ALL	1ST	1.96894	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2018_NOX.SUM	NO2	ANNUAL	ALL	1ST	1.95513	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2015_NOX.SUM	NO2	ANNUAL	ALL	1ST	1.92618	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2018_PM10.SUM	PM10	24-HR	ALL	1ST	5.6199	453600	3641900	443.08	443.08	0	18071924	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2017_PM10.SUM	PM10	24-HR	ALL	1ST	5.18403	453600	3642000	443.26	443.26	0	17042524	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2016_PM10.SUM	PM10	24-HR	ALL	1ST	4.99847	453600	3642200	443.07	443.07	0	16042524	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2015_PM10.SUM	PM10	24-HR	ALL	1ST	4.84005	453600	3641900	443.08	443.08	0	15070224	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2014_PM10.SUM	PM10	24-HR	ALL	1ST	4.78997	452629.3	3641720.73	440.37	440.37	0	14051424	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2017_PM10.SUM	PM10	ANNUAL	ALL	1ST	0.99454	453600	3641900	443.08	443.08	0	1 YEARS	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2016_PM10.SUM	PM10	ANNUAL	ALL	1ST	0.8918	453600	3641900	443.08	443.08	0	1 YEARS	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2014_PM10.SUM	PM10	ANNUAL	ALL	1ST	0.87315	453600	3641900	443.08	443.08	0	1 YEARS	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2018_PM10.SUM	PM10	ANNUAL	ALL	1ST	0.87299	453600	3641900	443.08	443.08	0	1 YEARS	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2015_PM10.SUM	PM10	ANNUAL	ALL	1ST	0.8554	453600	3641900	443.08	443.08	0	1 YEARS	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2014-2018_PM25.SUM	PM25	1ST-HIGHEST 24-HR	ALL	1ST	4.36657	453700	3641900	443.46	443.46	0	5 YEARS	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2014-2018_PM25.SUM	PM25	ANNUAL	ALL	1ST	0.84563	453600	3641900	443.08	443.08	0	5 YEARS	MET	58	1	16990
AERMOD 21112	Coolidge SIL_2014-2018_SO2.SUM	SO2	1ST-HIGHEST MAX DAILY 1-HR	ALL	1ST	2.39942	438672.54	3647971.38	574.36	688.35	0	5 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2018_SOX.SUM	SO2	24-HR	ALL	1ST	0.44227	453600	3641900	443.08	443.08	0	18071924	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2017_SOX.SUM	SO2	24-HR	ALL	1ST	0.4054	453600	3642000	443.26	443.26	0	17042524	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2016_SOX.SUM	SO2	24-HR	ALL	1ST	0.39802	453600	3642200	443.07	443.07	0	16042524	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2015_SOX.SUM	SO2	24-HR	ALL	1ST	0.38111	453600	3641800	443.07	443.07	0	15062624	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2014_SOX.SUM	SO2	24-HR	ALL	1ST	0.37303	452629.3	3641720.73	440.37	440.37	0	14051424	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2016_SOX.SUM	SO2	3-HR	ALL	1ST	1.48812	438272.54	3649671.38	566.65	836.73	0	16012203	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2015_SOX.SUM	SO2	3-HR	ALL	1ST	1.42927	438572.54	3647271.38	560.49	688.35	0	15112624	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2014_SOX.SUM	SO2	3-HR	ALL	1ST	1.38924	438172.54	3649571.38	565.77	836.73	0	14103024	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2018_SOX.SUM	SO2	3-HR	ALL	1ST	1.31764	453700	3641800	443.46	443.46	0	18072612	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2017_SOX.SUM	SO2	3-HR	ALL	1ST	1.23016	452629.3	3641720.73	440.37	440.37	0	17121012	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2017_SOX.SUM	SO2	ANNUAL	ALL	1ST	0.07584	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2016_SOX.SUM	SO2	ANNUAL	ALL	1ST	0.06806	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2014_SOX.SUM	SO2	ANNUAL	ALL	1ST	0.06629	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2018_SOX.SUM	SO2	ANNUAL	ALL	1ST	0.06583	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990
AERMOD 21112	Coolidge SIL_2015_SOX.SUM	SO2	ANNUAL	ALL	1ST	0.06485	453600	3641900	443.08	443.08	0	1 YEARS	MET	16	1	16990

SRP Coolidge Significant Impact Analysis Results (8-11-21)

Pollutant	Average	Source Group	Rank	Model Conc. (ug/m3)	Significant Impact Level (ug/m3)	% SIL	Distance to Significance (km)
NO2	1ST-HIGHEST MAX DAILY 1-HR	ALL	1ST	71.26	7.5	950%	25
NO2	ANNUAL	ALL	1ST	2.25	1.0	225%	1.4
CO	1-HR	ALL	1ST	116.09	2000	6%	NA
CO	8-HR	ALL	1ST	45.80	500	9%	NA
PM25	1ST-HIGHEST 24-HR	ALL	1ST	4.37	1.2	364%	21.1
PM25	ANNUAL	ALL	1ST	0.85	0.2	423%	15.9
PM10	24-HR	ALL	1ST	5.62	5.0	112%	0.79
PM10	ANNUAL	ALL	1ST	0.99	1.0	99%	NA
SO2	1ST-HIGHEST MAX DAILY 1-HR	ALL	1ST	2.40	7.8	31%	NA
SO2	3-HR	ALL	1ST	1.49	25	6%	NA
SO2	24-HR	ALL	1ST	0.44	5.0	9%	NA
SO2	ANNUAL	ALL	1ST	0.08	1.0	8%	NA

ARM2 with minimum and maximum ambient ratios of 0.5 and 0.9, respectively for NOx to NO2 conversion.

The PM2.5 modeled concentration includes a secondary contribution (see attached MERPs calculation).

The area is non-attainment for PM10. However, PM10 was modeled and compared to the SILS and NAAQS.

Modeled emissions and stack parameters for existing units are from the 2008 Coolidge application. Emission rates reflect worst case startup/shut down rates.

SRP Coolidge NAAQS Analysis Results (8-11-21)

Model	File	Pollutant	Average	Group	Rank	Conc/Dep	East (X)	North (Y)	Elev	Hill	Flag	Time	Met File	Sources	Groups	Receptors
AERMOD 21112	Coolidge NAAQS_2014-2018_NO2.SUM	NO2	8TH-HIGHEST MAX DAILY 1-HR	ALL	1ST	103.59537	438672.54	3647971.38	574.36	688.35	0	5 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2014-2018_NO2.SUM	NO2	8TH-HIGHEST MAX DAILY 1-HR	SRP	1ST	103.59223	438672.54	3647971.38	574.36	688.35	0	5 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2014-2018_NO2.SUM	NO2	8TH-HIGHEST MAX DAILY 1-HR	STING	1ST	11.30507	452200	3642700	439.19	439.19	0	5 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2017_NOX.SUM	NO2	ANNUAL	ALL	1ST	3.69701	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2016_NOX.SUM	NO2	ANNUAL	ALL	1ST	3.34896	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2014_NOX.SUM	NO2	ANNUAL	ALL	1ST	3.19732	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2015_NOX.SUM	NO2	ANNUAL	ALL	1ST	3.13801	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2018_NOX.SUM	NO2	ANNUAL	ALL	1ST	3.07895	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2017_NOX.SUM	NO2	ANNUAL	SRP	1ST	3.69138	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2016_NOX.SUM	NO2	ANNUAL	SRP	1ST	3.34238	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2014_NOX.SUM	NO2	ANNUAL	SRP	1ST	3.19185	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2015_NOX.SUM	NO2	ANNUAL	SRP	1ST	3.13245	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2018_NOX.SUM	NO2	ANNUAL	SRP	1ST	3.07358	453600	3642000	443.26	443.26	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2018_NOX.SUM	NO2	ANNUAL	STING	1ST	1.27025	452200	3642700	439.19	439.19	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2017_NOX.SUM	NO2	ANNUAL	STING	1ST	1.25215	452200	3642700	439.19	439.19	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2014_NOX.SUM	NO2	ANNUAL	STING	1ST	1.19651	452200	3642700	439.19	439.19	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2016_NOX.SUM	NO2	ANNUAL	STING	1ST	1.15419	452200	3642700	439.19	439.19	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2015_NOX.SUM	NO2	ANNUAL	STING	1ST	1.134	452200	3642700	439.19	439.19	0	1 YEARS	MET	29	3	16990
AERMOD 21112	Coolidge NAAQS_2014-2018_PM10.SUM	PM10	24-HR	ALL	6TH	41.05397	452200	3642700	439.19	439.19	0	15111324	MET	71	3	17062
AERMOD 21112	Coolidge NAAQS_2014-2018_PM10.SUM	PM10	24-HR	SRP	6TH	4.90295	453700	3641900	443.46	443.46	0	17070324	MET	71	3	17062
AERMOD 21112	Coolidge NAAQS_2014-2018_PM10.SUM	PM10	24-HR	STING	6TH	40.97719	452200	3642700	439.19	439.19	0	15110724	MET	71	3	17062
AERMOD 21112	Coolidge NAAQS_2014-2018_PM10.SUM	PM10	ANNUAL	ALL	1ST	13.39957	452200	3642700	439.19	439.19	0	5 YEARS	MET	71	3	17062
AERMOD 21112	Coolidge NAAQS_2014-2018_PM10.SUM	PM10	ANNUAL	SRP	1ST	1.12668	453600	3642000	443.26	443.26	0	5 YEARS	MET	71	3	17062
AERMOD 21112	Coolidge NAAQS_2014-2018_PM10.SUM	PM10	ANNUAL	STING	1ST	12.88563	452200	3642700	439.19	439.19	0	5 YEARS	MET	71	3	17062
AERMOD 21112	Coolidge NAAQS_2014-2018_PM25.SUM	PM25	8TH-HIGHEST 24-HR	ALL	1ST	3.6882	453700	3641900	443.46	443.46	0	5 YEARS	MET	71	3	16990
AERMOD 21112	Coolidge NAAQS_2014-2018_PM25.SUM	PM25	8TH-HIGHEST 24-HR	SRP	1ST	3.68026	453700	3641900	443.46	443.46	0	5 YEARS	MET	71	3	16990
AERMOD 21112	Coolidge NAAQS_2014-2018_PM25.SUM	PM25	8TH-HIGHEST 24-HR	STING	1ST	3.12347	452200	3642700	439.19	439.19	0	5 YEARS	MET	71	3	16990
AERMOD 21112	Coolidge NAAQS_2014-2018_PM25.SUM	PM25	ANNUAL	ALL	1ST	1.77668	452200	3642700	439.19	439.19	0	5 YEARS	MET	71	3	16990
AERMOD 21112	Coolidge NAAQS_2014-2018_PM25.SUM	PM25	ANNUAL	SRP	1ST	1.12668	453600	3642000	443.26	443.26	0	5 YEARS	MET	71	3	16990
AERMOD 21112	Coolidge NAAQS_2014-2018_PM25.SUM	PM25	ANNUAL	STING	1ST	1.28856	452200	3642700	439.19	439.19	0	5 YEARS	MET	71	3	16990

SRP Coolidge NAAQS Analysis Results (8-11-21)

Pollutant	Average	Source Group	Rank	Model Conc. (ug/m3)	Background (ug/m3)	Total Conc. (ug/m3)	Standard (ug/m3)	%Standard	Comment
NO2	8TH-HIGHEST MAX DAILY 1-HR	ALL	1ST	103.60	20.00	123.60	188	66%	
NO2	ANNUAL	ALL	1ST	3.70	15.69	19.38	100	19%	
PM25	8TH-HIGHEST 24-HR	ALL	1ST	3.69	21.00	24.69	35	71%	24-hr secondary PM2.5 contribution < 0.01 ug/m3
PM25	8TH-HIGHEST 24-HR	SRP	1ST	3.68	21.00	24.68	35	71%	
PM25	8TH-HIGHEST 24-HR	STING	1ST	3.12	21.00	24.13	35	69%	
PM25	ANNUAL	ALL	1ST	1.78	8.10	9.88	12	82%	Annual secondary PM2.5 contribution < 0.01 ug/m3
PM25	ANNUAL	SRP	1ST	1.13	8.10	9.23	12	77%	
PM25	ANNUAL	STING	1ST	1.29	8.10	9.39	12	78%	
PM10	24-HR	ALL	6TH	41.05	96.00	137.05	150	91%	Max impact occurs inside Stinger Welding fence.
PM10	24-HR	STING	6TH	40.98	96.00	136.98	150	91%	

ARM2 with minimum and maximum ambient ratios of 0.5 and 0.9, respectively for NOx to NO2 conversion.
The PM2.5 modeled concentration includes a secondary contribution (see attached MERPs calculation).
The area is non-attainment for PM10. However, PM10 was modeled and compared to the SILS and NAAQS.
Modeled emission are from the 2008 Coolidge application and represent startup/shut down rates. Stack parameters were also obtained from the 2008 application.
NO2 background values are the 2018-19 design values from Tucson (AQS No. 4-19-1028).
PM10 bacground values were calculated from the 2017-19 monitor in Coolidge (AQS No. 4-21-3004) which demonstates attainment.
PM2.5 background values are the 2018-19 design values from Orange Grove (AQS No. 4-19-0011).
"ALL" source group represents all 28 turbines at Coolidge and nearby Stinger Welding.

MERPS Calculation

Secondary PM2.5 Calculation (Use Source 4007, Gila Co, AZ - 500 TPY, 10m Release)

Precursor	Modeled Emissions of Hypothetical Source (MER) (TPY)	Release Height of Hypothetical Source (m)	Project Emissions (TPY)	Max 24-hr Impact of Hypothetical Source (MIHS) (ug/m3)	Max Annual Impact of Hypothetical Source (MIHS) (ug/m3)	24-hr Project Impact (ug/m3)	Annual Project Impact (ug/m3)
NOx	500	10	141.50	0.011	0.001	0.003	0.0003
SO2	500	10	4.70	0.035	0.002	0.000	0.0000
					Total	**0.003**	**0.0003**

Project Impact = max impact hypothetical source divided by emissions of hypo source multiplied by the project emissions

Example 24hr NOx:

0.011 ug/m3 divided by 500 TPY times 141.5 TPY = 0.003 ug/m3

Ozone Impact Calculation (Use Source 4007, Gila Co, AZ - 500 TPY, 10m Release)

Precursor	Modeled Emissions of Hypothetical Source (MER) (TPY)	Release Height of Hypothetical Source (m)	Project Emissions (TPY)	Max 8-hr Impact of Hypothetical Source (MIHS) (ppb)	Calculated 8-hr Project Impact (ppb)	
NOx	500	10	141.5	1.226	0.35	
VOC	500	10	50.2	0.025	0.003	
				Total	**0.35**	Ozone SIL = 1.0 ppb

Project Impact = max impact hypothetical source divided by emissions of hypo source multiplied by the project emissions

Example 8hr NOx:

1.226 ppb divided by 500 TPY times 141.5 TPY = 0.35 ppb

REFERENCES

1. Guideline on Air Quality Models, Appendix W of 40 CFR Part 51, U.S. Environmental Protection Agency, 2017).

2 . Air Dispersion Modeling Guidelines for Arizona Air Quality Permits, Air Quality Permit Section, Arizona Department of Environmental Quality, November 1, 2019.

3. Auer, Jr., A.H. "Correlation of Land Use and Cover with Meteorological Anomalies." Journal of Applied Meteorology, 17:636-643, 1978.

4. 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.

5. Ambient Monitoring Guidelines for Prevention of Significant Deterioration, EPA-450/4-87-007, EPA, May 1987.

6. Monitoring Guidelines at p. 9.

7. United States Census Bureau, population in 2019 was 462,789. https://www.census.gov/quickfacts/fact/table/pinalcountyarizona/PST045219.

Pinal County, population in 2020 was 425,264. https://www.pinalcountyaz.gov/News/Pages/Article.aspx?myID=1632
.

8. U.S. EPA, DRAFT Guidance for Ozone and Fine Particulate Matter Permit Modeling, February 10, 2020.

APPENDIX C

Construction Phase Emissions Calculations

Emission Summary

Source	Emissions (tons/yr)					
	VOC	CO	NO_X	$PM/PM_{10}/PM_{2.5}$	SO_2	CO_2
Construction Vehicles and Equipment	5.69	39.67	100.40	3.22	3.66	2876.61
Light Duty Construction Vehicle Tailpipe Emissions	0.19	2.74	0.19	0.02	0.02	103.77
Wind Erosion - Storage Piles	-	-	-	0.01	-	-
Haul Roads Vehicle Traffic	-	-	-	0.02		-
Total	5.88	42.41	100.59	3.27	3.68	2980.38

Annual Emissions (Max Emitting Year)

Equipment Type	HP	VMT	Load Factor	Annual Hours of Use [1]	Emission Factors [2,3]						Max Annual Emissions (tpy)					
					HC	CO	NO_X	$PM/PM_{10}/PM_{2.5}$	SO_2	CO_2	VOC [4]	CO	NO_X	$PM/PM_{10}/PM_{2.5}$	SO_2	CO_2
Construction Vehicles and Equipment																
Mowers	25	NA	0.590	0.000	0.446	2.270	4.493	0.234	0.16	13.2	0.000	0.000	0.000	0.000	0.000	0.000
Bulldozers	130	NA	0.590	0.000	0.362	1.393	3.942	0.188	0.16	106	0.000	0.000	0.000	0.000	0.000	0.000
Dump Trucks	500	NA	0.800	2523.429	0.178	1.354	4.168	0.114	0.16	7.6	0.248	1.883	5.797	0.159	0.223	9.589
Portable Generators	100	NA	0.430	0.000	0.374	2.485	4.756	0.201	0.16	75	0.000	0.000	0.000	0.000	0.000	0.000
Jackhammers	25	NA	0.430	0.000	0.856	6.386	5.232	0.489	0.16	13.2	0.000	0.000	0.000	0.000	0.000	0.000
Delivery Trucks	500	NA	0.800	7508.571	0.178	1.354	4.168	0.114	0.16	7.6	0.738	5.604	17.248	0.472	0.662	28.533
Fork Lifts	100	NA	0.430	8071.714	0.393	3.802	4.519	0.269	0.16	31.2	0.349	3.383	4.020	0.240	0.142	125.919
75-ton Crane	420	NA	0.430	8735.143	0.170	0.885	4.387	0.077	0.16	129	0.687	3.579	17.742	0.310	0.647	563.417
250-ton Crane	420	NA	0.430	8071.714	0.170	0.885	4.387	0.077	0.16	129	0.635	3.307	16.395	0.287	0.598	520.626
Excavators	250	NA	0.590	0.000	0.330	1.201	3.846	0.169	0.16	245	0.000	0.000	0.000	0.000	0.000	0.000
Air Compressors	25	NA	0.430	27477.000	0.856	6.386	5.232	0.489	0.16	14.4	0.648	4.836	3.962	0.370	0.121	197.834
Air Tools	25	NA	0.430	6726.429	0.856	6.386	5.232	0.489	0.16	13.2	0.159	1.184	0.970	0.091	0.030	44.394
Tuggers	500	NA	0.800	5005.714	0.178	1.354	4.168	0.114	0.16	7.6	0.492	3.736	11.499	0.315	0.441	19.022
Concrete Pumps	100	NA	0.430	331.714	0.374	2.485	4.756	0.201	0.16	77.9	0.014	0.091	0.174	0.007	0.006	12.920
Welders	25	NA	0.430	16770.000	0.856	6.386	5.232	0.489	0.16	11.3	0.396	2.951	2.418	0.226	0.074	94.751
Pumps	100	NA	0.430	24731.143	0.374	2.485	4.756	0.201	0.16	77.9	1.019	6.774	12.967	0.548	0.436	963.278
Road Pavers	500	NA	0.800	2523.429	0.178	1.354	4.168	0.114	0.16	233	0.248	1.883	5.797	0.159	0.223	293.979
Cement Trucks	500	NA	0.800	617.143	0.178	1.354	4.168	0.114	0.16	7.6	0.061	0.461	1.418	0.039	0.054	2.345
Light Duty Construction Vehicle Tailpipe Emissions																
LDGV	NA	187714.286	NA		0.903	13.222	0.903	0.093	0.113	501.504	0.187	2.736	0.187	0.019	0.023	103.771
Total											**5.881**	**42.409**	**100.591**	**3.242**	**3.681**	**2980.377**

[1] Equipment that have zero hours of annual use are used in phases that do not overlap with the phase in which the worst-case annual emissions will occur. Hours of use are scaled by the load factor that represents how long a piece of equipment typically operates during a workday

[2] Emission factors for construction vehicles and equipment were obtained from Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling Compression-Ignition are in units of g/hp-hr. Emission factors for light duty construction vehicle tailpipe emissions were obtained from Chapter 5 of the 2002 Periodic Ozone Emission Inventory by the Maricopa Association of Governments and are in units of g/mi.

[3] CO2 Emission factor for LDGV obtained from the Updated Emission Factors of Air Pollutants from Vehicle Operations in GREETTM Using MOVES. And U.S. EPA. Greenhouse Gas and Energy Consumption Rates for On-Road Vehicles: Updates for MOVES 2014. Available Online at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100NNUQ.pdf.

[4] VOC is conservatively approximated as being equal to HC.

Storage Piles

Source	Pollutants	Number of Piles	Hours Stored per Year (hrs/yr)	Emission Factor (lbs/hr/pile)	Emissions (tons/yr)
Wind Erosion - Aggregate Pile	PM_{10}	5	1800	0.00005	0.000225
	PM			0.0001	0.00045
Wind Erosion - Dirt/Sand Pile	PM_{10}	10	1800	0.0006	0.0054
	PM			0.0012	0.0108
			Totals	**PM_{10}**	**0.005625**
				PM	**0.01125**

Haul Roads - Vehicle Traffic

Source	Pollutants	Vehicle Miles Travelled per Year	Emission Factor (lbs/VMT)	Emissions (tons/yr)
Skidsteer and Wheeled Loaders	PM_{10}	100	0.19	0.010
	PM		0.73	0.037
Ready Mix Trucks	PM_{10}	100	0.17	0.009
	PM		0.66	0.033
		Totals	**PM_{10}**	**0.018**
			PM	**0.070**

Note: Storage pile and haul road emission factors were obtained from the ADEQ General Permit Application for Concrete Batch Plants. No Concrete Batch Plant will be associated with this project.

EXHIBIT B-2 – GROUNDWATER AVAILABILITY ASSESSMENT

This page intentionally left blank.

SWCA®
ENVIRONMENTAL CONSULTANTS
Sound Science. Creative Solutions.®

20 East Thomas Road, Suite 1700
Phoenix, Arizona 85012
Tel 602.274.3831 Fax 602.274.3958
www.swca.com

TECHNICAL MEMORANDUM

To: William McClellan, Spence Wilhelm, and Joseph Gardner, Salt River Project

From: Chris Garrett, Hydrologist

Date: November 24, 2021

Re: **Coolidge Expansion Groundwater Availability Assessment / SWCA Project No. 00065028-000-PHX**

PURPOSE OF MEMO

The purpose of this technical memorandum is to assess the physical and regulatory availability of the proposed water supply for the Coolidge Expansion project, in order to demonstrate that the proposed water supply would be sufficient for the project and use of that water supply would be consistent with both regulation and groundwater management direction in the region.

HYDROLOGIC SETTING

General Hydrologic Framework

The Coolidge Expansion project is located on 100 acres in Pinal County (Township 6 South Range 8 East Section 10), in an area designated under Arizona's groundwater regulatory framework as the Eloy subbasin of the Pinal Active Management Area (AMA). Physically, the Eloy groundwater subbasin is part of the basin-and-range physiographic province of Central Arizona, which is characterized by deep alluvial basins separated by mountain ranges generally trending northwest to southeast. Extensive, deep, and productive aquifers are associated with the alluvial basins. For the purposes of groundwater supply, the consolidated rock of the bounding mountain ranges is considered to be an impervious boundary to the alluvial basin aquifers.

The Eloy subbasin is located in the eastern part of the Pinal AMA and is bounded by the Sacaton and San Tan Mountains to the north, by the Tortilla Mountains and Picacho Mountains to the east (Figure 1). To the west, the Eloy subbasin is separated from the Maricopa-Stanfield subbasin by a subsurface ridge of shallow, buried bedrock referred to generally as Casa Grande Ridge. This ridge trends in a north-south direction from the Sacaton Mountains to the Silver Reef Mountains and lies about 150 feet below the land surface (Liu et al. 2014).

ADWR generally divides the alluvial aquifers in the Pinal AMA into four major hydrogeologic units (Liu et al 2014). From top to bottom these are:

- Upper Alluvial Unit (UAU). The UAU consists of largely unconsolidated interbedded sand and gravel, with some finer-grained materials present as discrete lenses. In the vicinity of the project, the UAU is estimated to be about 350 feet thick.

- Middle Silt and Clay Unit (MSCU). The MSCU is a fine-grained unit that consists primarily of silt, clay, and sand. In the vicinity of the project, the MSCU is estimated to be from 1,250 to 1,600 feet thick.

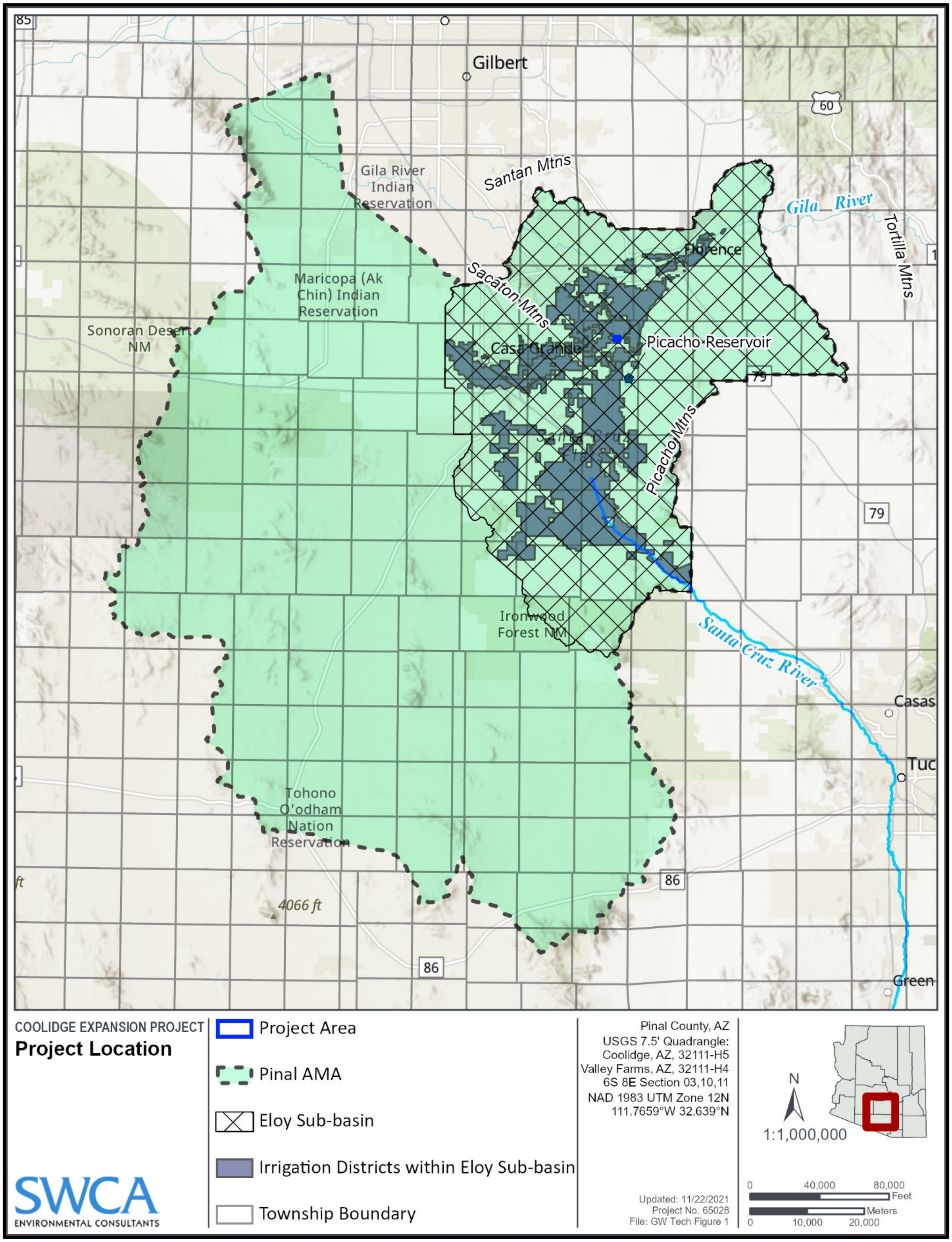
- Lower Conglomerate Unit (LCU). The LCU is the deepest water-bearing unit and consists of semi- to fully-consolidated coarse sediments, such as granite fragments, cobbles, boulders, sands, and gravels. In the vicinity of the project, the LCU is estimated to be from 1,500 to 2,000 feet thick.

- Hydrogeologic Bedrock Unit (HBU). Hydrologically, the underlying bedrock unit is considered to be impermeable and not part of the productive aquifer.

The thickness of alluvial aquifer materials in the subbasin ranges from several hundred feet along the margins of the basin, to almost 10,000 feet in the center of the basin. Taken together, the productive aquifer (UAU, MSCU, LAU) in the vicinity of the project site is estimated to be roughly 3,000 to 4,000 feet thick (Liu et al 2014; Richard et al. 2007). The on-site wells are completed in the UAU and MSCU.

In the Pinal AMA, recharge to the aquifer occurs both naturally and from anthropogenic activities. Natural recharge includes mountain-front recharge, infiltration from major stream channels (primarily the Gila River and the Santa Cruz River), and groundwater underflow from adjacent basins. Anthropogenic recharge includes agricultural return flow, canal infiltration, recharge from Picacho Reservoir, effluent recharge (Casa Grande Wastewater Treatment Plant), and artificial recharge either directly or through groundwater-savings facilities. The largest source of recharge is agriculture incidental recharge and canal losses, which account for about 80 percent of all inflows.

Discharge of groundwater from the Pinal AMA aquifers largely consists of pumping (over 90 percent of all discharge), relatively small amounts of evapotranspiration along riparian areas where groundwater is relatively shallow, and groundwater discharge to adjacent basins. Groundwater near the project generally flows from the southeast to the northwest, where it generally discharges as underflow into the East Salt River Valley.


Gilbert
60
Santan Mtns
Gila River Indian Reservation
Gila River
Tortilla Mtns
Florence
Sacaton Mtns
Maricopa (Ak Chin) Indian Reservation
Sonoran Desert NM
Casa Grande
Picacho Reservoir
79
Picacho Mtns
Ironwood Forest NM
Santa Cruz River
Casas
Tuc
Tohono O'odham Nation Reservation
86
4066 ft
Green
COOLIDGE EXPANSION PROJECT
Project Location
Project Area
Pinal AMA
Eloy Sub-basin
Irrigation Districts within Eloy Sub-basin
Township Boundary
SWCA
ENVIRONMENTAL CONSULTANTS
Pinal County, AZ
USGS 7.5' Quadrangle:
Coolidge, AZ, 32111-H5
Valley Farms, AZ, 32111-H4
6S 8E Section 03,10,11
NAD 1983 UTM Zone 12N
111.7659°W 32.639°N
Updated: 11/22/2021
Project No. 65028
File: GW Tech Figure 1
N
1:1,000,000
0 40,000 80,000 Feet
0 10,000 20,000 Meters

Approximately 150 registered wells are located within 1 mile of the proposed project area,[1] as shown in Appendix A (Arizona Department of Water Resources [ADWR] 2021a, 2021b) (Figure 2). The ADWR well registry files (also known as the 55-files) generally have information provided to ADWR at the time the well is drilled, which may or may not reflect current conditions. However, about half of these wells are also found in the ADWR Groundwater Site Inventory (GWSI). Unlike the well registry files, the ADWR GWSI contains verified field measurements over time, including water levels, pumping rates, and water quality.

The well records confirm that the alluvial sediments near the project site are both deep and highly productive. The vast majority of wells are drilled less than 1,000 feet deep, with several exceptions including one well drilled to a depth of 2,500 feet. Reported pumping capacities are as high as 1,950 gallons per minute (gpm).

Site-specific drilling, well construction, and water quality monitoring have also been conducted for the existing Coolidge Generating Station (AMEC 2009; Schlumberger 2011). These studies estimated that on-site wells could produce from 1,000 to 1,800 gpm, but recommended drawing water from a depth above 400 feet, due to elevated concentrations of total dissolved solids at depth (discussed further below).

Groundwater Levels and Trends

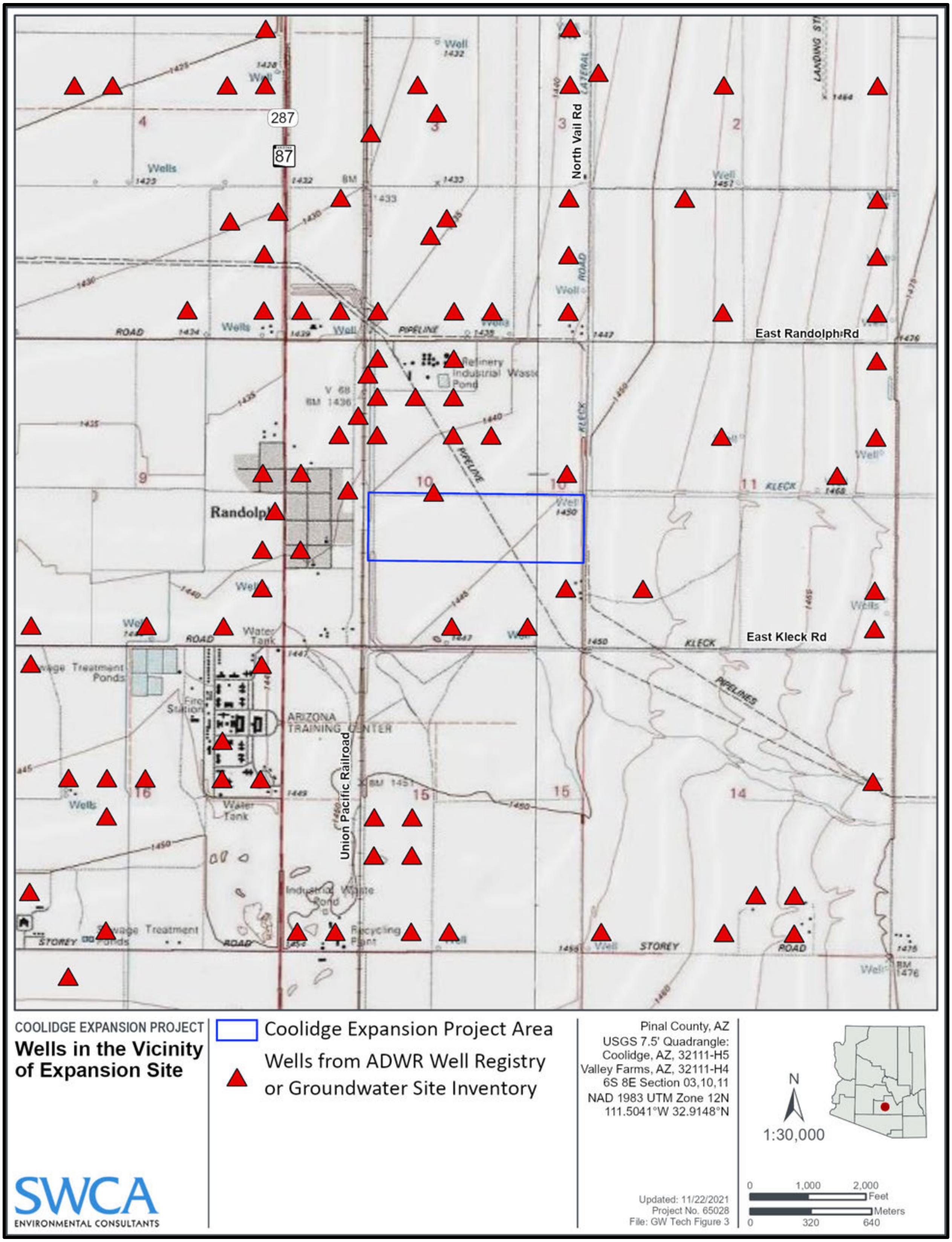
Several wells in the near vicinity of the project are index wells, which means that ADWR monitors their water levels on a regular basis. These wells represent the best source for understanding long-term water level trends in the vicinity of the project. Hydrographs for two of these wells are shown Appendix B, and well locations are shown in Figure 3.

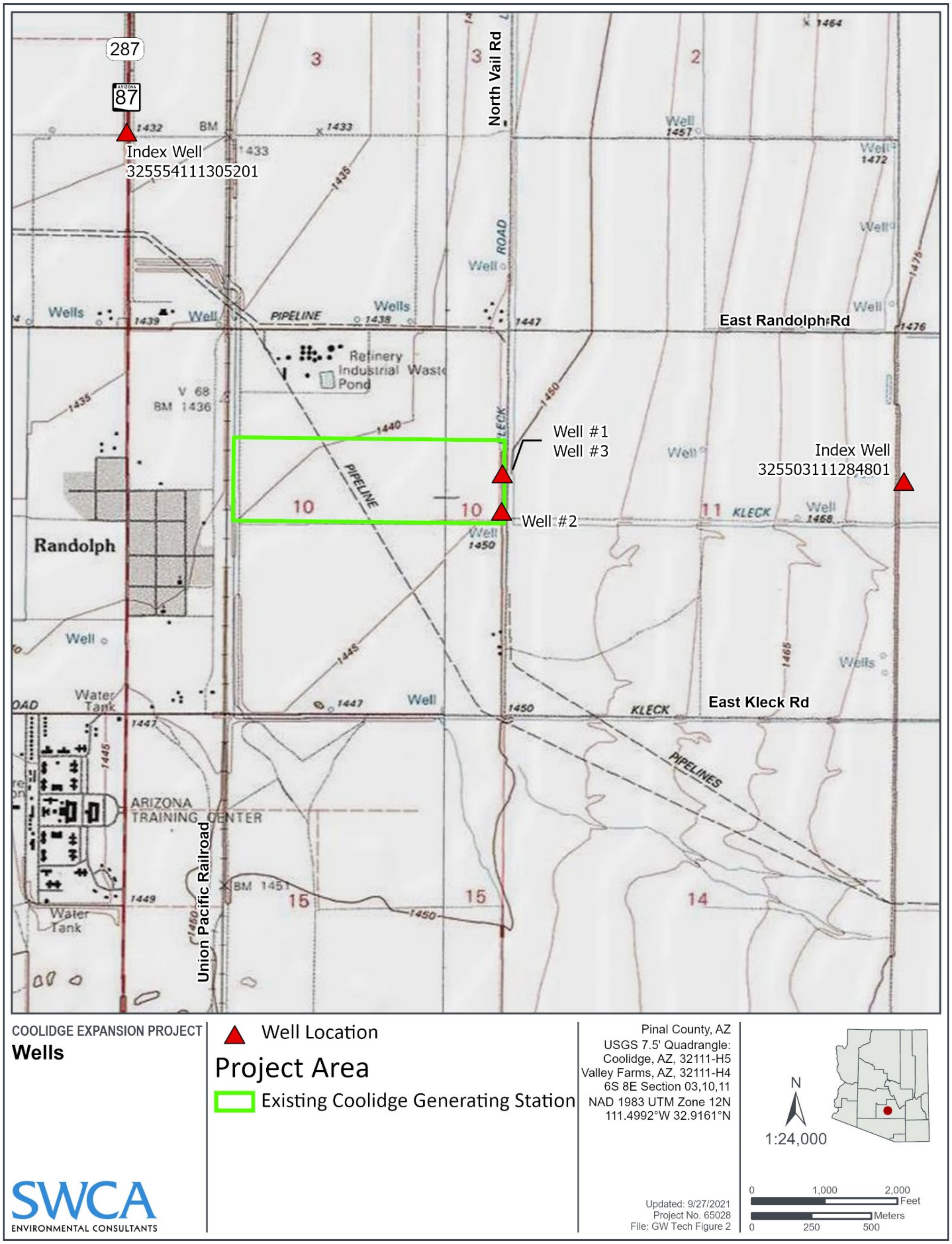
The groundwater levels shown in Appendix B follow a typical trend in the Pinal AMA. The post-war boom in agriculture in Pinal County was supplied almost entirely by groundwater, and as a result groundwater levels in the basin declined steeply until the 1970s. Near the Coolidge Expansion project, the decline in groundwater levels reached well over 100 feet, as shown in Figure B-1 in Appendix B. However, a number of statewide trends that started in the 1970s resulted in a halt and then a reversal of groundwater level declines in the basin. These include reduced groundwater pumping, increased use of Central Arizona Project (CAP) water, and flood recharge from large flood events along the Gila and Santa Cruz Rivers. As a result, by the turn of the century groundwater levels in the vicinity of the project had largely recovered to 1940s levels. In the last two decades groundwater levels have held relatively steady, though in recent years they appear to have started to decline again.

The estimated depth to water at the project site could range from about 70 feet, based on nearby index wells (hydrographs shown in Appendix B), to around 100 feet, based on the site-specific well sampling (note that this sampling occurred roughly a decade ago). The most recent groundwater levels available from the ADWR GWSI indicate that depth to water ranges from 63 to 103 feet below ground surface[2].

[1] Records were obtained from the ADWR GWSI and Well Registry for Sections 2, 3, 4, 9, 10, 11, 14, 15, and 16 of Township 6 South, Range 8 East.

[2] An additional 11 recent water level measurements were obtained from the same sections listed in the previous footnote. All water levels were measured in either 2019 or 2020, and ranged from 63 to 103 feet with an average of 85 feet.


North Vail Rd
East Randolph Rd
East Kleck Rd
Union Pacific Railroad
Randolph
ARIZONA TRAINING CENTER
Refinery Industrial Waste Pond
Sewage Treatment Ponds
Fire Station
Water Tank
Industrial Waste Pond
Recycling Plant
PIPELINE
PIPELINES
KLECK
STOREY
ROAD
287
87
COOLIDGE EXPANSION PROJECT
Wells in the Vicinity of Expansion Site
Coolidge Expansion Project Area
Wells from ADWR Well Registry or Groundwater Site Inventory
Pinal County, AZ
USGS 7.5' Quadrangle:
Coolidge, AZ, 32111-H5
Valley Farms, AZ, 32111-H4
6S 8E Section 03,10,11
NAD 1983 UTM Zone 12N
111.5041°W 32.9148°N
N
1:30,000
0 1,000 2,000 Feet
0 320 640 Meters
SWCA ENVIRONMENTAL CONSULTANTS
Updated: 11/22/2021
Project No. 65028
File: GW Tech Figure 3


287
87
Index Well
325554111305201
North Vail Rd
East Randolph Rd
Well #1
Well #3
Well #2
Index Well
325503111284801
Randolph
East Kleck Rd
Union Pacific Railroad
ARIZONA TRAINING CENTER
Refinery Industrial Waste Pond
PIPELINE
PIPELINES
COOLIDGE EXPANSION PROJECT
Wells
Well Location
Project Area
Existing Coolidge Generating Station
Pinal County, AZ
USGS 7.5' Quadrangle:
Coolidge, AZ, 32111-H5
Valley Farms, AZ, 32111-H4
6S 8E Section 03,10,11
NAD 1983 UTM Zone 12N
111.4992°W 32.9161°N
N
1:24,000
0 1,000 2,000 Feet
0 250 500 Meters
Updated: 9/27/2021
Project No. 65028
File: GW Tech Figure 2
SWCA
ENVIRONMENTAL CONSULTANTS

Groundwater Quality

The Pinal AMA generally has groundwater quality that is acceptable for most uses. However, there are known water quality concerns in the basin including areas of high dissolved solids, nitrates, and fluoride. The most pertinent and detailed source for assessing groundwater quality available near the site is from the site-specific water quality obtained from exploratory drilling conducted for the Coolidge Generating Station (AMEC 2009) and water quality collected after drilling three production wells (Schlumberger 2011). Water quality results are shown in Tables 1 and 2.

Prior to drilling wells for the Coolidge Generating Station, water samples from exploratory boring were collected at specific depths in the aquifer and analyzed for water quality. The depth-specific results are shown in Table 1 for common inorganic analytes. The drilling found that overall water quality deteriorated at depth with high levels of dissolved solids, sulfate, and fluoride. As a result, recommendations from the investigation included focusing water production to depths of less than 400 feet.

Table 1. Depth-Specific Water Quality Samples Collected Near the Project Site (June 2008)

Analyte	Units	Depth of 1,804 feet	Depth of 850 feet	Depth of 700 feet	Depth of 520 feet	Depth of 335 feet	Depth of 295 feet	Depth of 240 feet	Notes
Total dissolved solids	mg/L	16,000	5,700	7,700	8,500	1,200	1,300	720	Secondary non-enforceable standard of 500 mg/L for drinking water; water generally less than 1,000 mg/L is considered fair (World Health Organization 2017)
Nitrate	mg/L	NT	NT	0.94	<0.50	7.4	5.5	3.1	Arizona aquifer water quality standard of 10 mg/L
Sulfate	mg/L	NT	2,500	1,300	1,200	250	300	140	Secondary non-enforceable standard of 250 mg/L for drinking water
Arsenic	mg/L	NT	NT	0.0086	0.0093	0.003	<0.003	0.0037	Arizona aquifer water quality standard of 0.050 mg/L
Fluoride	mg/L	NT	1.7	2.8	3.1	0.61	0.77	0.98	Arizona aquifer water quality standard of 4.0 mg/L

Source: AMEC (2009)
NT – Not tested due to limited sample volume
Mg/L – milligrams per liter

Following the exploratory water sampling, three production wells were drilled for the Coolidge Generating Station (Wells #1, #2, and #3 on Figure 3), and water quality samples were collected from two of these wells (Schlumberger 2011). Guided in part by the findings, the screened intervals of these production wells were limited to less than 600 feet. Water quality results for Wells #1 and #2 are shown in Table 2. Relatively high concentrations of total dissolved solids, nitrate, and sulfate were observed, consistent with the depth-specific sampling.

Table 2. Water Quality Samples Collected from Coolidge Generating Station Production Wells

Analyte	Units	Well #1 Well Reg. 55-218256 Screened from 260–580 feet (August 2009)	Well #2 Well Reg. 55-218257 Screened from 220–580 feet (July 2009)	Notes
Total dissolved solids	mg/L	650	2,600	Secondary non-enforceable standard of 500 mg/L for drinking water; water generally less than 1,000 mg/L is considered fair (World Health Organization 2017)
Nitrate	mg/L	3.2	10	Arizona aquifer water quality standard of 10 mg/L
Sulfate	mg/L	120	760	Secondary non-enforceable standard of 250 mg/L for drinking water
Arsenic (dissolved)	mg/L	0.0092	<0.0050	Arizona aquifer water quality standard of 0.050 mg/L
Fluoride	mg/L	1.3	1.1	Arizona aquifer water quality standard of 4.0 mg/L

Source: Schlumberger (2011)
Mg/L – milligrams per liter

Land Subsidence

An undesirable effect of the pumping of groundwater from alluvial sediments is subsidence, or lowering, of the land surface. Land subsidence has occurred in multiple locations in Arizona since the early 1990s, with some areas estimated to have subsided more than 18 feet since that time.

Land subsidence is caused by the compaction of alluvium once groundwater is removed from the void space between particles. The pores in the alluvium that were held open by water pressure collapse, causing lowering of the land surface over wide areas. In addition, where subsidence occurs over areas of extreme bedrock topography, differential subsidence can occur. This occurs when two parts of the surface are subsiding at different rates, which can cause earth fissures at the surface.

The Eloy sub-basin is a known area of subsidence and is actively monitored by ADWR. Subsidence monitoring using satellite-based Interferometric Synthetic Aperture Radar (InSAR) allows subsidence to be quantified in detail across the entire basin. An example of the subsidence that has occurred in the project area in the 11 years between 2010 and 2021 is shown in Appendix C (ADWR 2021c). Over this time period, from 0 to 10 centimeters of subsidence has occurred in the project area, up to roughly 1 centimeter per year. No earth fissures have been identified in the near vicinity of the Coolidge Expansion project; the nearest earth fissures occur roughly 3 to 4 miles eastward, near the margin of the basin.

REGULATORY FRAMEWORK

Arizona Management of Groundwater Resources

Groundwater overdraft has been recognized as a problem in Arizona since before World War II. In 1980, Arizona passed the Groundwater Management Act (Arizona Revised Statutes [ARS], Title 45, Chapter 2), which established a statewide system of groundwater management, including requiring groundwater rights within areas of critical management known as AMAs.

Groundwater may not be pumped within an AMA without authorization from ADWR. Authorization can take several forms:

- The Groundwater Management Act established a number of Irrigation Grandfathered Rights, based on historic agricultural uses. These rights are for a specific annual volume of groundwater with extraction and use tied to a specific piece of land.
- The Groundwater Management Act also established Type 1 Non-Irrigation Grandfathered Rights, which are associated with retired agricultural land, with the use of the water tied to a specific piece of land.
- Another form of groundwater right established were Type 2 Non-Irrigation Grandfathered Rights, which are for specific uses other than retired agricultural land and can be transferred to new locations.
- There are also a number of withdrawal permits that ADWR can issue for specific uses, including for dewatering, drainage, poor quality water, mineral extraction, and industrial use.
- Later additions to the groundwater management code in 1986 and 1994 included programs to manage the storage of surface water underground in various ways. Storing water underground results in the assignment of "long-term storage credits". These long-term storage credits can be later recovered from groundwater wells that have been permitted to do so.

Management Direction for the Pinal AMA

The 1980 Groundwater Management Act established a management goal for each AMA. Unlike the other major AMAs—Phoenix, Tucson, and Prescott—which have a management goal of safe-yield (in which groundwater use does not exceed natural recharge), the management goal of the Pinal AMA has always been focused on the continued use of groundwater rather than safe-yield:

> The management goal of the Pinal active management area is to allow development of non-irrigation uses as provided in this chapter and to preserve existing agricultural economies in the active management area for as long as feasible, consistent with the necessity to preserve future water supplies for non-irrigation uses. (ARS 45-562.B)

In subsequent management plans for the Pinal AMA, ADWR noted that "this goal is unquantified in the Groundwater Code. The law does not specify how much water must be preserved for non-irrigation uses, nor does it list any criteria by which to determine how long agricultural economies should be preserved." (ADWR 1991). Faced with this loose definition, ADWR developed an interpretation of the management goal to be "the preservation of groundwater between 1,000 and 1,200 feet below land surface for future non-irrigation uses" (ADWR 1991). In other words, agricultural demands would be able to use any groundwater above 1,000 feet (pumping from deeper than this was anticipated to be uneconomical for most agricultural users), which would leave accessible groundwater for future residential, commercial, and industrial uses. This goal commonly has been termed "planned depletion" (ADWR 1999).

In the latest management plan (the Fourth Management Plan, currently in effect), ADWR has explicitly moved away from the concept of "planned depletion" and instead determined that "in the [Pinal AMA], groundwater is managed to ensure that all users have a groundwater supply into the future." (ADWR 2020).

While specific goals and interpretations have varied over time, common to all groundwater management in the Pinal AMA since the adoption of the 1980 Groundwater Management Code is the concept that the trend in the Pinal AMA will be the continued use of groundwater, with a long-term transition from agricultural groundwater uses to non-agricultural groundwaters uses, including industrial uses. The regulatory structure in place in the Pinal AMA is designed to ensure this transition is done in a manner that tends to reduce groundwater use overall. Two pertinent examples of this inherent reduction include the following:

- The conversion of Irrigation Grandfathered Rights to Type 1 Non-Irrigation Grandfathered Rights generally involves a reduction in groundwater use. As a specific example, the Coolidge Generating Station previously converted 100 acres of an existing Irrigation Grandfathered Right to a Type 1 Non-Irrigation Right (58-111884.0011). The water duty for the original irrigation right was 4 acre-feet per acre, resulting in a right to pump about 370 acre-feet of groundwater per year. Once converted, however, the Type 1 Non-Irrigation Right was reduced to 279 acre-feet. This is because by law the conversion is capped at a per-acre water duty of 3 acre-feet (ARS 45-469.F). In essence, the conversion of this water right automatically reduced future groundwater use by 25 percent.

- When using long-term storage credits, generally only 95 percent of the stored water is allowed to be recovered (ARS 45-852.01). This provides for an overall improvement in aquifer storage in the long term, while still allowing flexibility for recovering groundwater for use.

Specific Management Direction for Large-Scale Power Plants

ADWR regulates conservation requirements for large-scale power plants, as described in the Fourth Management Plan:

> The objective of the Industrial Conservation Program is to move industrial users within the Pinal AMA (PAMA) to the greatest level of water use efficiency economically attainable given the use of the latest available water conservation technology. The 4MP also provides incentives to encourage industrial users to replace groundwater supplies with renewable supplies. Efficient use of groundwater and the replacement of groundwater sources with renewable supplies contribute to the achievement and maintenance of the PAMA water management goal. (ADWR 2020)

The Industrial Conservation Program applies to industrial users, which are defined as “a person who uses groundwater withdrawn pursuant to a Type 1 or Type 2 non-irrigation grandfathered right (GFR) or a withdrawal permit for an industrial use.” Note that if a facility instead obtains water from a water provider, requirements are encompassed in the Municipal Conservation Program.

Within the Industrial Conservation Program, there are separate requirements for steam electric generation or combined-cycle power plants, and for cooling towers associated with combustion turbine power plants. The Coolidge Expansion project would be a combustion turbine peaking power plant. The requirements for a combustion turbine power plant under the Industrial Conservation Program apply only under three conditions:

- ADWR regulates power plants that produce or are designed to produce more than 25 megawatts of electricity.
- ADWR regulates combustion turbine power plants with cooling capacity of 250 tons or more.
- The power plant obtains water under a groundwater right or industrial withdrawal permit, and not from a municipal provider.

However, while the Coolidge Expansion project would produce more than 25 megawatts, peaking plants are specifically not included in this category. The existing Coolidge Generating Station is identified in the Fourth Management Plan and is noted not to be included: “In addition, there is a peaking plant in [Pinal AMA] that does not meet the definition of a Large-scale Power Plant.” (ADWR 2020)

Because the Coolidge Expansion project is a peaking plant, the specific requirements for combustion turbine power plants are not applicable. As a general industrial user, the Coolidge Expansion project would have to comply with general conservation requirements outlined in the Industrial Conservation Program (§ 6-602). These include the following:

1. Avoid waste and make diligent efforts to recycle water.
2. Do not use water for non-residential single-pass cooling or heating purposes, unless the water is reused for other purposes.
3. Use low-flow plumbing fixtures.
4. Use plants listed in the ADWR Low Water Use/Drought Tolerant Plant List for the Pinal AMA for landscaping to the maximum extent feasible and use a water-efficient irrigation system.
5. Do not serve or use groundwater for the purpose of watering landscaping plants within any publicly owned right-of-way of a highway, street, road, sidewalk, curb, or shoulder which is used for travel in any ordinary mode, including pedestrian travel, unless the plants are listed in ADWR's Low Water Use/Drought Tolerant Plant List for the Pinal AMA.
6. Do not serve or use groundwater for the purpose of maintaining water features, including fountains, waterfalls, ponds, water courses, and other artificial water structures, within any publicly owned right-of-way of a highway, street, road, sidewalk, curb, or shoulder which is used for travel in any ordinary mode, including pedestrian travel.

Specific Management Direction for Municipal Water Suppliers

The nearby area is served by Arizona Water Company. Arizona Water Company is considered a municipal water supplier by ADWR under the Fourth Management Plan, and as such must comply with the Municipal Conservation Program. Part of the Municipal Conservation Program is that entities known as "individual users" have specific conservation requirements. Specific individual user requirements are identified for turf-related facilities, public rights-of-way, and large cooling towers not belonging to a power facility. If water were obtained from Arizona Water Company, the proposed project does not have specific individual user requirements under the Municipal Conservation Program. However, Arizona Water Company still has specific conservation requirements for the overall system, and if obtaining water from Arizona Water Company, the Coolidge Expansion project may be required to meet other conservation requirements and best management practices implemented by Arizona Water Company.

Future Projections within the Pinal AMA

ADWR has a long history of assessing groundwater conditions in the Pinal AMA and projecting groundwater use into the future, starting in 1989 with the first Pinal AMA groundwater flow model (Wickham and Corkhill 1989). The results of the most recent modeling effort by ADWR for Pinal AMA were published in 2019, generally raising concerns about future groundwater supplies in the Pinal AMA (ADWR 2019). This modeling effort projected groundwater conditions through the year 2115 and incorporated all known groundwater demands including groundwater supplies already committed and approved for assured water supplies and recovery of long-term storage credits. Municipal and industrial demands were maintained at 2015 levels, and agricultural demands were projected based on a number of factors. Overall, the combined projections show that annual rates of groundwater pumping decrease somewhat over the next century, but not substantially so.

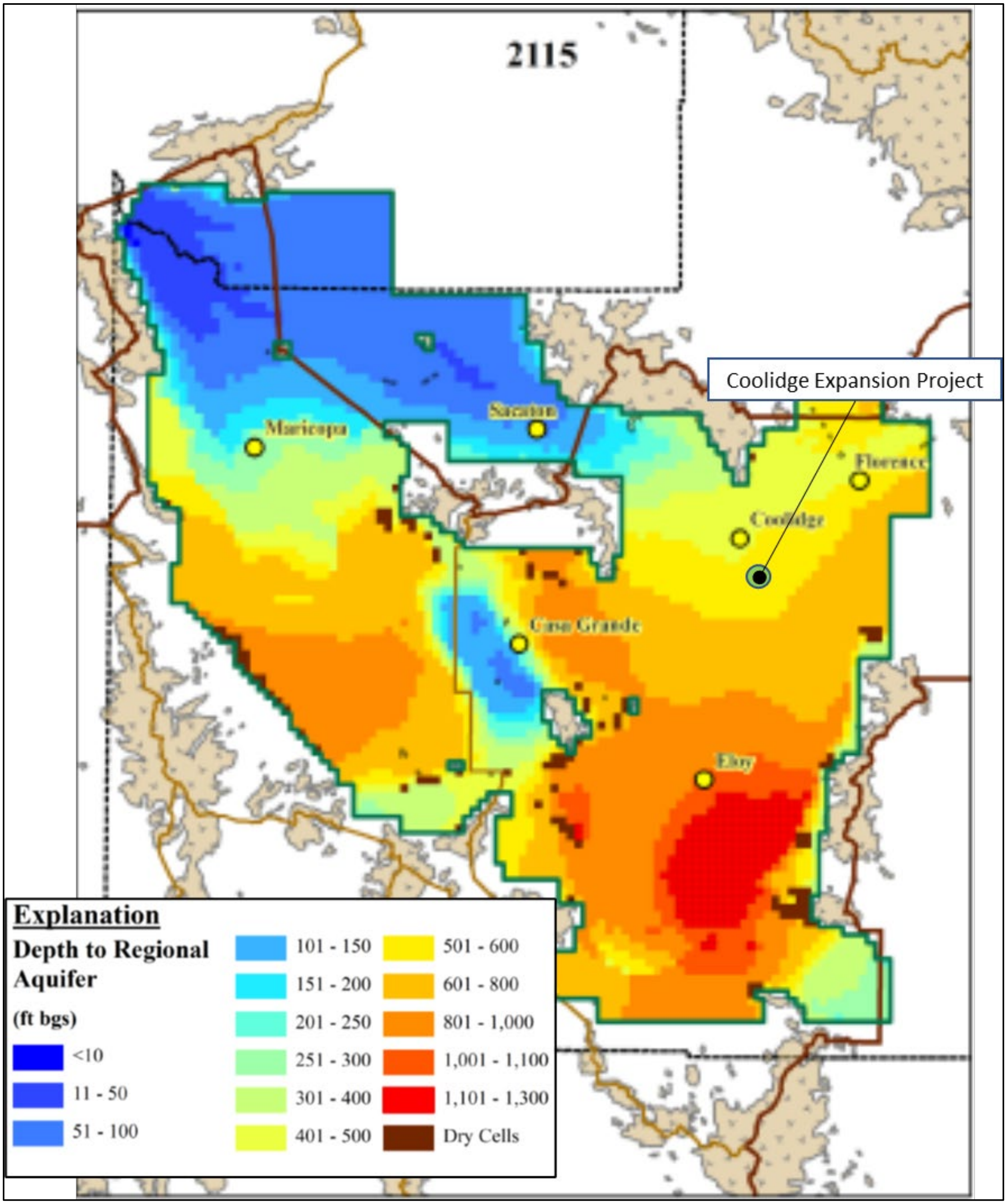


Figure 4. Excerpt from ADWR's 2019 Pinal AMA modeling report, showing predicted depth to groundwater at end of planning period (2115) (ADWR 2019)

The modeling report focused on whether committed or projected water supplies could physically be obtained from the aquifer. The modeling found that of the roughly 80 million acre-feet projected to be required by the year 2115, only 72 million acre-feet were physically available, suggesting that the Pinal AMA may experience a long-term shortfall of 8 million acre-feet (ADWR 2019).

The modeled shortfalls noted are for the Pinal AMA as a whole, and it is important to recognize that because the model is based on physical availability, the specific location of the pumping determines whether a shortfall is anticipated. Most of the critical shortfalls are predicted to occur south of Eloy, roughly 15–20 miles from the project area. By contrast, based on ADWR's modeling for their 100-year planning horizon, in the immediate vicinity of the project the following conditions are anticipated:

- Current (2015) depth to water used in the model = 100–150 feet below ground surface. This is largely consistent with the site-specific information available.
- Projected (2115) depth to water resulting from modeled groundwater demands = 500–600 feet below ground surface.
- Projected (2115) drawdown resulting from modeled groundwater demands = 400–500 feet.
- Remaining saturated thickness of aquifer above 1,110 feet in 2115 = 500–600 feet.

Based on the modeling, groundwater supplies are likely to remain physically available in the vicinity of the project site for ADWR's 100-year planning horizon, with substantial remaining saturated thickness in the aquifer. The life expectancy for the Coolidge Expansion Project is estimated to be 30 years which is a shorter duration than 100 years. In addition, the Coolidge Expansion Project will not contribute to long term shortfall in the Pinal AMA because the water supply will be sourced from long-term storage credits.

Ramifications of Colorado River Supplies and the Drought Contingency Plan

The delivery of surface water from the Colorado River via the CAP is an important source for overall water supplies in the Pinal AMA. With respect to water supplies from the Colorado River, the State of Arizona is currently operating under a Drought Contingency Plan. The Drought Contingency Plan was signed in May 2019 by all seven Colorado River basin states, the U.S. Department of the Interior, and the U.S. Bureau of Reclamation. The provisions of the plan expire in 2026. This plan imposes additional restrictions on the delivery of Colorado River water; these restrictions are in addition to interim guidelines previously agreed to by the seven Colorado River upper and lower basin states.

The Colorado River Compact of 1922 is the foundation of the "Law of the River," which governs Colorado River water management. State apportionments were established in agreements approved subsequent to the Colorado River Compact, and other laws and court decisions have further added to the Law of the River. The Drought Contingency Plan was developed in recognition of ongoing shortages in the Colorado River watershed and is designed to reduce the risks of Lake Mead declining to critical elevations by requiring Arizona, California, and Nevada to contribute additional water to Lake Mead storage at predetermined elevations and creating additional flexibility to incentivize additional voluntary conservation of water to be stored in the lake. These new contributions of water by each lower basin state are an overlay and are in addition to the shortage volumes outlined in the Colorado River Interim Guidelines for Lower Basin Shortages and the Coordinated Operations for Lake Powell and Lake Mead (known as the 2007 Guidelines) (U.S. Bureau of Reclamation 2007). Like the shortage elements of the 2007 Guidelines, new contributions would increase as Lake Mead's elevation declines, providing protection against Lake Mead's declining to critically low elevations. The Drought Contingency Plan also provides for the potential recovery of contributions later, should Lake Mead conditions improve significantly.

Every year in August, the U.S. Bureau of Reclamation makes a 24-month projection of anticipated reservoir levels, which in turn determines the level of restrictions that will be in place for the coming year. In August 2021, projections indicated that Lake Mead reservoir water levels (on January 1, 2022) would be at or below 1,075 feet and at or above 1,050 feet (U.S. Bureau of Reclamation 2021). This is the first time that Lake Mead has reached what are known as "Tier 1" conditions in the Drought Contingency Plan. Under these management protocols, Arizona foregoes 512,000 acre-feet of allocated Colorado River water.

These restrictions do not mean the complete absence of Colorado River water for Arizona. Arizona's allocation from the Colorado River is 2.8 million acre-feet, of which one-half is allocated to main-stem users, and the other one-half is accessed by users via the CAP aqueduct. To date, voluntary restrictions under the 2007 Interim Guidelines and Drought Contingency Plan have not greatly impacted individual users, as most of the 192,000 acre-feet of forbearance under Tier 0 shortages came from the excess CAP water pool, which reduced water available for groundwater replenishment activities but avoided drastic effects on contracted users. Under Tier 1 shortages, the reductions would spread more widely and in particular would heavily impact agricultural users in Pinal County (or more specifically, the reductions come from the "CAP Ag Pool" allotment). Within Arizona, passage of the Drought Contingency Plan also provided for mitigation measures (including wet water replacement and financial compensation) that are meant to reduce impacts on end users. In Pinal County, this includes funding to rehabilitate groundwater infrastructure (wells) to increase access to groundwater by those entities that had been using a CAP allotment.

With respect to the Coolidge Expansion project, there are two primary ramifications from the ongoing shortages on the Colorado River:

- The long-term groundwater supply already has been modeled by ADWR to be insufficient over the next 100 years. That modeling was reported in 2019 and appears to assume full delivery of CAP Ag Pool water through 2030. This assumption is now incorrect. This means the groundwater shortage eventually facing users in the Pinal AMA may be worse than that modeled by ADWR and reported in 2019. The overall effect of the CAP reductions will depend on how individual agricultural users respond. For example, some agricultural lands may be fallowed rather than switching to groundwater pumping.
- Shortages of Colorado River water will reduce the amount of water available for underground storage of water (either directly or through groundwater savings facilities) though existing credits would still be available for purchase and use.

EFFECTS OF PROPOSED PROJECT WATER SUPPLY

Proposed Water Supply

The Coolidge Expansion project is estimated to require up to 233 acre-feet per year. Multiple options for obtaining this water supply were considered:

- Previously, the Coolidge Generating Station converted 100 acres of an existing Irrigation Groundwater Right to a Type 1 Non-Irrigation Grandfathered Right (58-111844.0011). An additional 98 acres remain from the original Irrigation Groundwater Right that could be converted. The amount of the new right after the conversion would be determined by ADWR but based on the previous conversion could be assumed to be roughly 273 acre-feet.
- The Coolidge Generating Station has acquired long-term storage credits through the purchase of CAP water delivered to the Hohokam Irrigation District Groundwater Savings Facility. The current long-term storage account balance is approximately 5,600 acre-feet, as well as additional

credits that are stored under SRP's account in the Pinal AMA. To recover this water, an ADWR Recovery Well Permit is required. Well #1 and Well #2 are permitted to recover up to 350 acre-feet per year and up to 717 acre-feet per year, respectively, of water from the long-term storage account. To date, the long-term storage account has not been used, as plant water demand has not exceeded the limit of the existing Type 1 Non-Irrigation Grandfathered Water Right.

- Alternatively, the Coolidge Expansion project could potentially obtain water directly from the Arizona Water Company Pinal Valley system.

After consideration, the second option was selected for the water supply for the Coolidge Expansion project. The water supply will be 100% derived from the recovery of long-term storage credits from the current balance of 5,600 AF and additional credits that are stored under SRP's account in the Pinal AMA. The water will be recovered from wells permitted by ADWR as recovery wells.

Effects of Proposed Water Supply

Reduction of overall groundwater use in Pinal AMA

The selection of long-term storage credits for the water supply for the project is the option that most reduces overall groundwater use in the Pinal AMA. To obtain long-term storage credits, groundwater is either physically recharged into the aquifer, or surface water is delivered to an entity so that entity does not have to pump groundwater under an existing groundwater right. In this case, the long-term storage credits were obtained by delivering CAP water to the Hohokam Irrigation District Groundwater Savings Facility. From a water accounting perspective, this mechanism is equivalent to using the CAP water directly at the facility. In addition, the act of recharging the water through a groundwater savings facility also results in a 5% addition to the aquifer that is not recovered.

Adherence to conservation requirements

As noted above, the Coolidge Expansion project would be considered a general industrial user and would have to comply with general conservation requirements outlined in the Industrial Conservation Program (§ 6-602). The two most substantial of these include the following:

1. Avoid waste and make diligent efforts to recycle water.
2. Do not use water for non-residential single-pass cooling or heating purposes, unless the water is reused for other purposes.

The Coolidge Expansion project does not use single-pass cooling. Overall, water consumption is anticipated to be similar to that of the existing Coolidge Generating Station. Based on reported operational data for 2016–2018, as shown in Table 3, the average water use (as measured in gallons per megawatt hour [MWh]) is substantially less than that for other generating plants in Arizona, as well as nationwide.

Table 3. Typical Water Use by Coolidge Generating Station, Compared to Averages

Year	Reported water use (acre-feet)*	Reported water use (milligal)	Reported generation (MWh)†	Calculated water use (gallons) per MWh
2020	198.41	64.7	499,566	129
2019	125.86	41.0	330,191	124

Year	Reported water use (acre-feet)*	Reported water use (milligal)	Reported generation (MWh)†	Calculated water use (gallons) per MWh
2018	64.22	20.9	155,333	135
2017	71.69	23.4	167,265	140
2016	72.22	23.5	167,695	140
Arizona Average‡				825
National Average¶				2,050

Notes:
* As reported to ADWR for groundwater right 58-111844.011 (ADWR 2021d)
† As reported to U.S. Energy Information Administration (USEIA) (2021a)
‡ As reported to USEIA (2021b); based on 2019 June usage reported for 18 natural gas power plants in Arizona
¶ As reported to USEIA (2021c); based on 2019 June usage reported for 418 natural gas power plants across the United States

Physical Availability of Groundwater

From a regulatory perspective, while the groundwater being used is considered to be water recovered from a groundwater savings facility, the groundwater must still be physically available at the point of recovery. Physically, this groundwater is available at the project site and under the most recent projections would remain physically available through 2115 even with substantial projected groundwater drawdown of 400 to 500 feet in the vicinity of the project. However, one ramification of these falling water levels is that water quality may substantially deteriorate as wells are deepened to access poor-quality groundwater below depths of 600 feet. This could require treatment prior to use or could reduce the available cycles before blowdown.

CONCLUSIONS

1. The Pinal AMA is an area of intensive groundwater use and is anticipated to experience substantial groundwater demands over the next 100 years, resulting in shortfalls within the basin overall.
2. The water supply selected for the proposed Coolidge Expansion project is the most sustainable of the options available, and would reduce groundwater use for the property site within the Pinal AMA.
3. The proposed plant would meet the conservation requirements under the Industrial Conservation Program and would use substantially less water than other similar facilities.
4. The recovered groundwater is physically available at the facility and is anticipated to be physically available based on modeled water conditions over the next 100 years.

LITERATURE CITED

AMEC Earth & Environmental, Inc. 2009. Exploration Analysis Report, Coolidge Generating Station, Exploratory Boring Program, Pinal County, Arizona. AMEC Project No. 08-115-05005. January 26.

Arizona Department of Water Resources (ADWR). 1991. Second Management Plan, 1990–2000, Pinal Active Management Area. January.

———. 1999. Third Management Plan, 2000–2010, Pinal Active Management Area. December.

———. 2019. 2019 Pinal Model and 100-Year Assured Water Supply Projection Technical Memorandum. October 11.

———. 2020. Pinal Active Management Area, Fourth Management Plan. December 14.

———. 2021a. Registry of Wells in Arizona (55-files). Available at: https://gisweb3.azwater.gov/WellReg. Accessed September 10, 2021.

———. 2021b. Groundwater Site Inventory. Available at: https://gisweb3.azwater.gov/gwsi. Accessed September 10, 2021.

———. 2021c. Total Land Subsidence in the Eloy Sub-Basin, Pinal County, Based on Radarsat-2 Satellite Interferometric Synthetic Aperture Radar (InSAR) Data, Time Period of Analysis: 11.0 Years, 05/15/2010 to 04/11/2021. Available at: https://new.azwater.gov/sites/default/files/PicachoArea05-2010to04-2021_8x11.pdf. Accessed October 13, 2021.

———. 2021d. Annual Water Withdrawal and Use Report, Groundwater Right 58-111884.0011. Available at: https://infoshare.azwater.gov/docushare/dsweb/HomePage. Accessed October 13, 2021.

Liu, S., K. Nelson, D. Yunker, W. Hipke, and F. Corkhill. 2014. Regional Groundwater Flow Model of the Pinal Active Management Area, Arizona, Model Update and Calibration. Arizona Department of Water Resources Model Report No. 26. February.

Richard, S.M., T.C. Shipman, L.C. Greene, and R.C. Harris. 2007. Estimated Depth to Bedrock in Arizona. Arizona Geological Survey Digital Geologic Map Series DGM-52, Version 1.0.

Schlumberger Water Services. 2011. Transcanada Coolidge Power, Well Drilling Report. Report No. 2873. March.

U.S. Bureau of Reclamation. 2007. Record of Decision: Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lake Powell and Lake Mead: Final Environmental Impact Statement. Washington, D.C.: U.S. Bureau of Reclamation. December 13.

———. 2021. Operation Plan for Colorado River System Reservoirs, August 2021 24-Month Study. August.

U.S. Energy Information Administration (USEIA). 2021a. Open Data Access Portal for Coolidge Generation Station, Net Generation, Annual. Available at: https://www.eia.gov/opendata/qb.php?category=6968&sdid=ELEC.PLANT.GEN.56948-ALL-ALL.A. Accessed October 13, 2021.

———. 2021b. Thermoelectric cooling water data. Available at: https://www.eia.gov/electricity/data/water/. Accessed October 13, 2021.

Wickham, M.P., and E.F. Corkhill. 1989. Pinal Active Management Area Regional Groundwater Flow Model Phase One: Hydrogeologic Framework, Water Budget and Phase One Recommendations. Arizona Department of Water Resources Modeling Report Number 1.

World Health Organization. 2017. Guidelines for Drinking-water Quality. Fourth Edition Incorporating the First Addendum.

APPENDIX A

Combined Records from ADWR Well Registry and Groundwater Site Inventory within Approximately 1 Mile of Project Area

Table A-1. Combined Records from ADWR Well Registry and Groundwater Site Inventory (GWSI) within Approximately 1 Mile of Project Area

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
Well #1		D-06-08-10ADD	218256	COOLIDGE POWER LLC		154	620	658	18		5/12/2009	
Well #2		D-06-08-10ADD	218257	COOLIDGE POWER LLC		154	640	620	18		5/4/2010	
Well #3		D-06-08-10ADD	218942	COOLIDGE POWER LLC								
Index Well	325503111284801	D-06-08 11ADA1	617559	PINAL LAND HOLDNGS, LLC	11/12/2020	73.2	365		18	UNUSED	6/15/1951	
Index Well	325554111305201	D-06-08 S04ADD1	605731	BRIGHTON 875, LLC	11/12/2020	70.7	600	600	20	UNUSED	9/27/1939	0
	325500111305501	D-06-08 09ADD			1/6/2014	76.9	400		16	UNUSED	12/6/1956	
	325432111314301	D-06-08 09CCD	605689	PINAL LAND HOLDINGS	12/3/2003	76.8	468	430	20	IRRIGATION	1/1/1949	500
	325447111305401	D-06-08 09DAD	605354	BARTLETT FARMS INC.	1/7/2019	76.2	700	16	20	UNUSED	1/1/1955	900
	325431111311801	D-06-08 09DCC	605357	BARTLETT FARMS INC.	1/7/2019	88.8	504	700	20	IRRIGATION	4/27/1946	800
	325439111305601	D-06-08 09DDA1	605355	BARTLETT FARMS INC.	11/9/1988	59.8	84	0	12	UNUSED	1/1/1935	0
	325439111305501	D-06-08 09DDA2	605356	BARTLETT FARMS INC.	12/18/2013	70.9	450	14	20	IRRIGATION	1/1/1935	400
	325429111310601	D-06-08 09DDC	605346	BARTLETT FARMS INC.	11/7/1988	127.9	700	700	16	IRRIGATION	12/30/1980	800
	325458111295101	D-06-08 10ADD	617778	COOLIDGE POWER LLC	11/4/1998	59.3	806	400	20	IRRIGATION	8/6/1956	1,180
	325458111304001	D-06-08 10BCA			12/18/2013	54.3	500		16	UNUSED	2/1/1947	
	325429111301901	D-06-08 10DCC	617779	PINAL LAND HOLDINGS, LLC	1/8/2019	91.4	1,330		20	UNUSED	4/22/1961	
	325440111295301	D-06-08 10DDA	617774	MCFARLAND, BC	1/10/1994	74.7	450		20	DOMESTIC	1/1/1940	
	325431111300101	D-06-08 10DDC	617780	PINAL LAND HOLDINGS, LLC	12/3/2003	67.6	800	176	20	UNUSED	6/9/1954	
	325507111291801	D-06-08 11ACB	617557	PINAL LAND HOLDNGS, LLC	11/4/1998	91.5	600		20	IRRIGATION	3/14/1961	
	325503111285001	D-06-08 11ADA2	617558	PINAL LAND HOLDNGS, LLC						IRRIGATION		

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
	325500111285901	D-06-08 11ADC	617560	PINAL LAND HOLDNGS, LLC			1216		20	IRRIGATION	5/4/1959	
	325440111284901	D-06-08 11DDA	617561	PINAL LAND HOLDNGS, LLC	1/9/2019	63.1	500		12	UNUSED	7/1/1950	
	325439111284901	D-06-08 11DDD	617562	PINAL LAND HOLDINGS, LLC	1/9/2019	243.6	300		12	IRRIGATION	1/1/1951	
	325342111294701	D-06-08 14CCC	625234	PINAL LAND HOLDNGS, LLC	11/8/2017	108.8	450	450	20	IRRIGATION	5/1/1953	600
	325348111292401	D-06-08 14CDA			1/13/1958	109.49	225			UNUSED	2/1/1950	
	325342111290401	D-06-08 14DCD1	504821	COOPER, TJ	11/12/1993	104	360	360	6	DOMESTIC	12/4/1983	20
	325339111302001	D-06-08 15DCC	625235	PINAL LAND HOLDNGS, LLC	11/8/1988	89.9	186	400	20	UNUSED	4/1/1944	500
	325428111305301	D-06-08 16AAA	615428	AZ STATE LAND DEPT.	1/7/2019	90.8	630	600	16	IRRIGATION	4/21/1971	750
	325405111310501	D-06-08 16ADC	615429	AZ STATE LAND DEPT.	1/7/2019	88.1	400	600	20	IRRIGATION	1/12/1950	750
	325403111305301	D-06-08 16ADD	615430	AZ STATE LAND DEPT.	1/7/2019	93	600	600	20	IRRIGATION	1/1/1960	100
	325405111313601	D-06-08 16BDC1	605686	PINAL LAND HOLDINGS, LLC			320	480	20	IRRIGATION	1/1/1933	500
	325407111320701	D-06-08 16BDC2	605687	ANDREW & JOELLA FERGUSON	12/5/2007	81.4	395	593	20	UNUSED	3/11/1950	800
	325403111312301	D-06-08 16BDD	605688	PINAL LAND HOLDINGS, LLC			600	600	16	IRRIGATION	1/1/1959	800
	325337111312401	D-06-08 16CDD	615432	AZ STATE LAND DEPT.	1/7/2019	103.1	910	900	20	IRRIGATION	6/9/1978	1,000
	325340111313701	D-06-08 16DCD					229		16	UNUSED	1/1/1933	
	325630111284901	D-06-08 N02DAD					300			IRRIGATION		
	325605111285801	D-06-08 N02DCA	610585	PINAL LAND HOLDINGS, LLC	12/16/2013	111.3	490	190	20	IRRIGATION	2/7/1950	800
	325624111284701	D-06-08 N02DDA	610584	PEN, JOHN & LOIS	12/4/2013	120.1	402	400	20	IRRIGATION	2/10/1952	450
	325641111295101	D-06-08 N03DAA	605240	KELLY & MEGAN FREEMAN	12/3/2007	91.7	352	300	20	IRRIGATION	7/18/1951	800
	325640111295001	D-06-08 N03DDA	605241	KELLY & MEGAN FREEMAN	1/11/2019	59.2	2,305	2,305	18	UNUSED	4/10/1964	1,000

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
	325640111295101	D-06-08 N03DDD			12/16/2013	88.2	400		20	UNUSED	2/23/1940	
	325628111305401	D-06-08 N04DAD			12/19/2013	59.7	400		16	UNUSED	6/10/1961	
	325551111305501	D-06-08 N04DDD			5/1/1951	89	235			IRRIGATION	5/1/1951	
	325559111292301	D-06-08 S02BDA	617563	PINAL LAND HOLDINGS, LLC	1/11/2019	77.8	365		20	IRRIGATION	1/27/1947	
	325550111292001	D-06-08 S02BDD			1/11/2019	59.4	250		20	UNUSED	1/1/1929	
	325525111291901	D-06-08 S02CDD	617775	MCFARLAND, BC	1/11/2019	64.3			20	UNUSED		
	325532111285201	D-06-08 S02DAA	617565	PINAL LAND HOLDNGS, LLC	11/12/2020	254.8	250		20	IRRIGATION	1/1/1929	
	325531111285301	D-06-08 S02DAD	617777	PINAL LAND HOLDNGS, LLC	11/8/2010	106.5	700		20	IRRIGATION	10/23/1948	
	325526111284801	D-06-08 S02DDD	617776	PINAL LAND HOLDNGS, LLC	12/16/2013	82.6				IRRIGATION		
	325547111295301	D-06-08 S03ADD	605237	A. WAYNE & HELEN L. FREEMAN	1/11/2019	83.5	380	360	20	IRRIGATION	11/18/1950	700
	325614111302101	D-06-08 S03BAA	605347	BARTLETT FARMS INC.	8/21/1996	107	500	500	20	UNUSED	1/1/1946	800
	325603111303601	D-06-08 S03BBD			11/10/1998	63.4	700		20	IRRIGATION	9/1/1957	
	325548111303401	D-06-08 S03BDC	605349	BARTLETT FARMS INC.	1/7/2019	87	600	600	20	UNUSED	1/1/1950	800
	325550111302101	D-06-08 S03BDD1			11/7/1988	80.5	250		20	UNUSED	1/1/1940	
	325549111302101	D-06-08 S03BDD2	605348	BARTLETT FARMS INC.	12/5/2007	82.5	2500	1,800	20	UNUSED	2/23/1956	1,600
	325547111302401	D-06-08 S03CAA					388		20	UNUSED		
	325531111303601	D-06-08 S03CCA	605352	BARTLETT FARMS INC.	12/5/2007	82.4	600	600	16	IRRIGATION	1/1/1975	600
	325524111305601	D-06-08 S03CCD			1/7/2019	81.6	516		20	IRRIGATION	3/13/1950	
	325522111301501	D-06-08 S03DCC	605238	A. WAYNE & HELEN L. FREEMAN	1/7/2019	83	800	800	20	UNUSED	1/1/1956	700
	325524111300701	D-06-08 S03DCD	809361	KELLY FREEMAN		230	570	570	16	UNUSED	4/1/1963	

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
	325532111295101	D-06-08 S03DDA	605239	A. WAYNE & HELEN L. FREEMAN	1/11/2019	94.4	460	300	20	IRRIGATION	4/1/1948	700
	325524111295201	D-06-08 S03DDD	605242	PETERSON, GE	1/13/1977	144.7	310	300	20	DOMESTIC	1/1/1918	10
	325612111305301	D-06-08 S04AAA1	605735	EVERGREEN-PYRAMID HIGHWAY CORNERS, LLC		175	414	414	16	UNUSED	1/1/1958	300
	325608111305301	D-06-08 S04AAA2	605733	EVERGREEN-PYRAMID HIGHWAY CORNERS, LLC		175	300	300	16	IRRIGATION	1/1/1962	850
	325609111305301	D-06-08 S04AAA3	605737	BRIGHTON 875, LLC	12/19/2013	71.1	400	380	16	UNUSED	1/1/1970	500
	325549111310401	D-06-08 S04ADC1			1/3/2019	80.7	375		20	UNUSED	1/9/1947	
	325548111310401	D-06-08 S04ADC2	501562	BRIGHTON 875, LLC	12/19/2013	72.7	340	340	16	IRRIGATION	4/1/1982	575
	325548111305601	D-06-08 S04ADD2	605738	BRIGHTON 875, LLC	11/10/1998	64.2	402	402	16	IRRIGATION	12/28/1969	600
	325549111312301	D-06-08 S04BDD1	605734	OWENS MORTGAGE INVESTMENT FUND	11/10/1998	67.2	312	312	20	IRRIGATION	3/1/1954	450
	325549111312901	D-06-08 S04BDD2	605736	OWENS MORTGAGE INVESTMENT FUND	11/10/1993	88.6	385	366	16	IRRIGATION	6/24/1959	500
	325522111310701	D-06-08 S04DCD	606013	BRIGHTON 875, LLC	12/19/2013	54.5	500	500	20	UNUSED		700
	325534111305701	D-06-08 S04DDA	606012	BRIGHTON 875, LLC	11/10/1993	87.9	600	600	16	IRRIGATION	8/5/1966	700
	325523111305701	D-06-08 S04DDD1	606011	STEARNS BANK, NA	2/26/1942	55.2	460	460	20	DOMESTIC	1/1/1939	300
	325522111305601	D-06-08 S04DDD2	606017	STEARNS BANK, NA			500		20	IRRIGATION		180
	325522111305801	D-06-08 S04DDD3	606010	BRIGHTON VILLAGE LANDBANK, LLC	3/18/1985	215.9	600	600	20	IRRIGATION	1/1/1977	600
	325639111284801	D-06-08-02AAA	610583	PINAL LAND HOLDINGS, LLC		153	1,440	1,297	13		5/3/2003	1,950
		D-06-08-02ADD	533191	SW GAS CORP.		0	230	0	0		10/22/1991	0
		D-06-08-02CAC	617564	PINAL LAND HOLDNGS, LLC		0	0	0	0			0

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
		D-06-08-03000	907688	EL PASO NATURAL GAS, ATTN: WILLIAM BALTZ		59	60	60	8		8/29/2007	
		D-06-08-03ADA	605236	KELLY & MEGAN FREEMAN		160	300	300	20		1/1/1947	700
		D-06-08-03BAD	605350	BARTLETT FARMS INC.		300	200	200	20		1/1/1940	0
		D-06-08-03BBB	527351	SOUTHWEST GAS CORP.		0	228	0	0		5/6/1990	0
		D-06-08-03BBD	605351	BARTLETT FARMS INC.		300	700	700	20		1/1/1950	800
		D-06-08-03CCC	620627	HANNAH, E		170	400	400	12		1/1/1974	35
		D-06-08-03CCC	620628	HANNAH, E		170	230	230	6		1/1/1950	20
		D-06-08-03CCD	605353	BARTLETT FARMS INC.		300	500	500	20		1/1/1935	600
		D-06-08-03CDC	201338	SALT RIVER PROJECT		0	250	80	6		12/15/2003	
		D-06-08-03CDC	230281	EL PASO NATURAL GAS CO. LLC. A KINDER MORGAN COMPANY			500	500	13		5/28/2019	
		D-06-08-03CDC	908684	EL PASO NATURAL GAS COMPANY		125	410	410	6		4/1/2008	30
		D-06-08-03DDD	805408	N.S.K. & B. PRTSHP.		0	350	240	20		12/31/1955	35
		D-06-08-04AB0	516243	SIMPSON, RHYNE JR.		0	20	0	6		1/13/1987	0
		D-06-08-04ADC	605732	BRIGHTON 875, LLC		165	375	375	16		4/15/1982	550
		D-06-08-09ADD	213269	ADEQ (ATTN: SAMAR BHUYAN)		43	55	53	2		9/28/2006	
		D-06-08-09ADD	213270	ADEQ (ATTN: SAMAR BHUYAN)		43	55	53	2		9/27/2006	
		D-06-08-09ADD	213271	ADEQ (ATTN: SAMAR BHUYAN)		43	55	53	2		9/28/2006	

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
		D-06-08-09ADD	213272	ADEQ (ATTN: SAMAR BHUYAN)		43	55	53	2		9/27/2006	
		D-06-08-09ADD	595761	ADEQ (ATTN: SAMAR BHUYAN)		41	57	54	2		8/26/2003	
		D-06-08-09ADD	595763	ADEQ (ATTN: SAMAR BHUYAN)		36	50	50	4		11/22/2002	
		D-06-08-09ADD	595766	ADEQ (ATTN: SAMAR BHUYAN)		36	50	50	4		11/21/2002	
		D-06-08-09ADD	908223	ADEQ (ATTN: SAMAR BHUYAN)		43	56	55	2		12/13/2007	
		D-06-08-09ADD	908224	ADEQ ATTN: SAMAR BHUYAN)		43	56	55	2		12/13/2007	
		D-06-08-09ADD	908225	ADEQ (ATTN: SAMAR BHUYAN)		43	57	55	5		12/14/2007	
		D-06-08-09ADD	917235	ADEQ		35	40	40			8/21/2014	
		D-06-08-09CCD	533192	SW GAS CORP.		0	230	0	0		10/22/1991	0
		D-06-08-09DDA	595758	ADEQ (ATTN: SAMAR BHUYAN)		36	50	50	4		11/27/2002	
		D-06-08-10000	910661	WESTERN EMULSIONS, INC.		23	30		8		4/23/2009	
		D-06-08-10000	923943	EDP RENEWABLES NORTH AMERICA LLC (ATTN: ERIC DESMARALS)			40				2/28/2020	
		D-06-08-10ABB	525240	SUNBELT REFINING CO.		0	0	0	0			0
		D-06-08-10ABC	524748	SUNBELT REFINING CO.		0	35	0	10		6/13/1989	0
		D-06-08-10ACA	218940	COOLIDGE POWER LLC								
		D-06-08-10ACB	218941	COOLIDGE POWER LLC								

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
		D-06-08-10B00	910128	COOLIDGE POWER, LLC ATTN: JOHN CASSADY								
		D-06-08-10BAB	524747	SUNBELT REFINING CO.		30	36	7	6		6/13/1989	0
		D-06-08-10BAC	522760	COOLIDGE LAND ACQUISITION COMPANY, LLC		0	0	0	0			0
		D-06-08-10BAC	524749	SUNBELT REFINING CO.		20	30	7	6		6/12/1989	0
		D-06-08-10BAD	522759	COOLIDGE LAND ACQUISITION COMPANY, LLC		180	493	493	12		1/29/1989	137
		D-06-08-10BAD	525241	SUNBELT REFINING CO.		18	30	30	2		8/7/1989	0
		D-06-08-10BCA	624101	TGF PROPERTIES LLC		250	600	600	20		1/1/1945	600
		D-06-08-10BCC	202727	ADEQ (ATTN: SAMAR BHUYAN)		40	59	59	4		3/25/2004	
		D-06-08-10BCC	640485	MOORE, M		0	0	0	0			0
		D-06-08-10BDB	217827	COOLIDGE POWER CORPORATION								
		D-06-08-10BDB	217828	COOLIDGE POWER CORPORATION								
		D-06-08-10CBC	536634	SW GAS CORP.		50	230	0	0		10/6/1992	0
		D-06-08-11AAA	805285	MCFARLAND, BONNYE,C		10	0	0	0		12/31/1929	0
		D-06-08-11CCA	530066	VAIL 160 LLC		80	300	300	10		11/30/1990	0
		D-06-08-11DDD	518655	CONNOLLY INVEST CORP.		0	0	0	0			0
		D-06-08-11DDD	523310	CONNOLLY INVEST CORP.		0	0	0	0			0
		D-06-08-14ADD	227270	EL PASO NATURAL GAS COMPANY LLC			500				7/2/2017	

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
		D-06-08-14ADD	550668	EL PASO NATURAL GAS CO. LLC., A KINDER MORGAN COMPANY		0	500	114	8		9/17/1995	0
		D-06-08-14DCA	507832	COOPER, THEODORE,J		160	440	260	6		4/30/1984	15
		D-06-08-14DCB	507871	JEFFREY SCOTT MARTIN		180	350	350	6		4/27/1984	10
		D-06-08-15CAA	202084	AARON ZOBRIST								
		D-06-08-15CAB	203457	SUNCRAFT CONSTRUCTION LLC								
		D-06-08-15CAC	596799	STEVE & KATHY BOWERS		104	355	355	7		5/31/2003	20
		D-06-08-15CAD	205740	DANIEL & ELISA SALAZAR								
		D-06-08-15CCC	909949	SCOTT E. & CINDY L. CASLER		132	390	390	6		10/26/2008	20
	325336111303901	D-06-08-15CCD	618029	PROLER INTERNTL CORP.		320	520	520	20		11/20/1976	500
		D-06-08-15CDD	596744	JOHN & ROSE LAXAMANA		105	385	385	7		3/10/2003	
		D-06-08-15CDD	915090	CASEY AND CYBIL GREEN		95	408	408	5		12/13/2013	20
		D-06-08-16ACC	610752	D E S		340	600	600	16		1/1/1960	750
		D-06-08-16ADB	482515	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			65	65	4		1/1/2000	
		D-06-08-16ADB	569533	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT		73	90	90	4		8/4/1998	
		D-06-08-16ADB	571851	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT								
		D-06-08-16ADB	571852	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			90	90	4			

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
		D-06-08-16ADB	571853	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			90	90	4			
		D-06-08-16ADB	571854	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			90	90	4			
		D-06-08-16ADB	571855	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			90	90	4			
		D-06-08-16ADB	580675	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			75				5/23/2000	
		D-06-08-16ADB	595852	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			65	65	4		1/21/2003	
		D-06-08-16ADB	595854	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			65	65	4		1/20/2003	
		D-06-08-16ADB	595856	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			65	65	4		1/17/2003	
		D-06-08-16ADB	595857	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			65	65	4		1/22/2003	
		D-06-08-16ADB	595859	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			65	65	4		1/16/2003	
		D-06-08-16ADB	595861	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			65	65	4		4/24/2003	
		D-06-08-16ADB	595863	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			80	80	2		1/23/2003	

Shown on Figure 3	GWSI ID	Cadastral location	Well Reg. ID	Owner Name	Date of Most Recent GWSI Water Level	Depth to Water (feet)*	Well Depth (feet)	Casing Depth (feet)	Casing Diameter (inches)	Well Use	Date Drilled	Pumping Rate (gpm)
		D-06-08-16ADB	595865	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			80	80	2		1/23/2003	
		D-06-08-16ADB	595866	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			80	80	2		1/23/2003	
		D-06-08-16ADB	595867	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			80	80	2		1/16/2003	
		D-06-08-16ADB	595868	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			80	80	2		1/15/2003	
		D-06-08-16ADB	595871	ARIZONA DEPARTMENT OF ADMINISTRATION RISK MANAGEMENT			80	80	2		1/14/2003	
		D-06-08-16ADD	610751	D E S		240	600	600	20		1/1/1960	100
		D-06-08-16BBA	592290	STATE OF ARIZONA		68	110	110	5		5/28/2002	
		D-06-08-16CAA	610753	ECONOMIC SECURITY		240	600	600	20		12/31/1970	750
		D-06-08-16CCA	610755	ECONOMIC SECURITY		200	600	600	20		12/31/1965	1,000
	325343111312301	D-06-08-16CCC	615431	AZ STATE LAND DEPT.		200	600	600	20		1/1/1965	1,000
		D-06-08-16CDD	610754	D E S		245	900	900	20		3/1/1977	1,000

Source: ADWR (2021a, 2021b)

* Water level shown represents GWSI water level, if available. Otherwise, water level represents information from ADWR well registry files, which typically is the water level when drilled.

APPENDIX B

Representative Long-Term Hydrographs

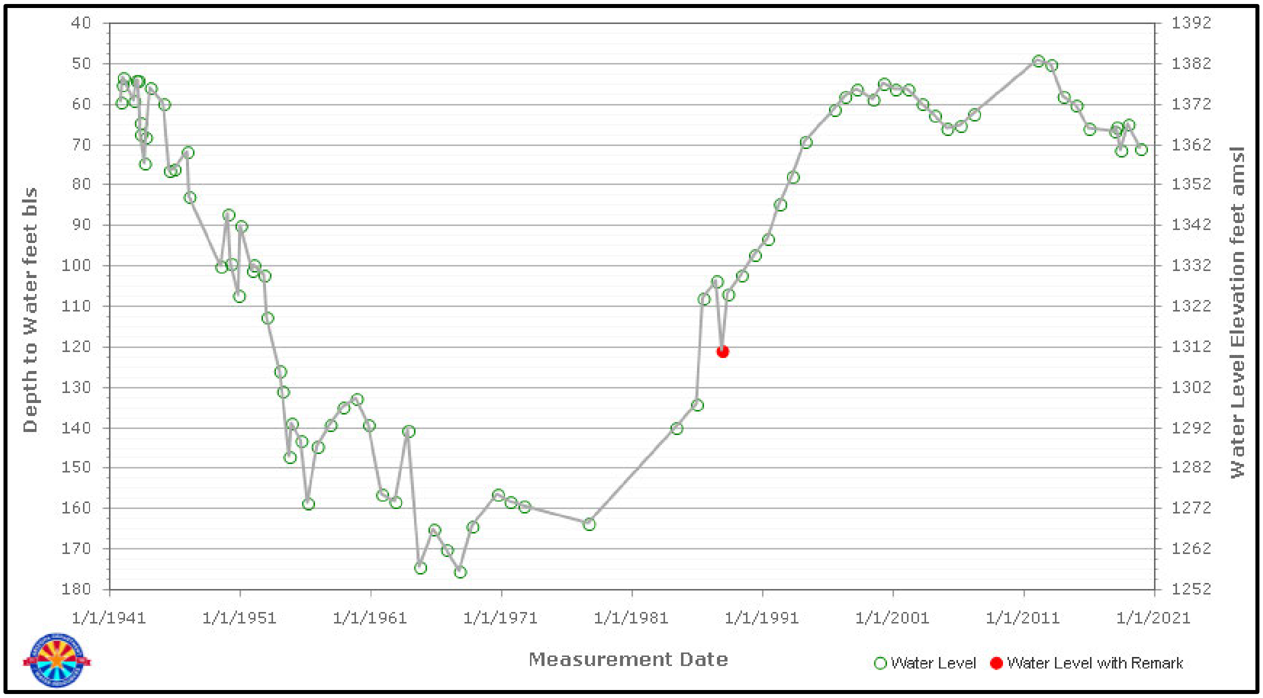


Figure B-1. Hydrograph of water levels in GWSI Well Site 325554111305201 (located approximately 1 mile northwest of the project area).

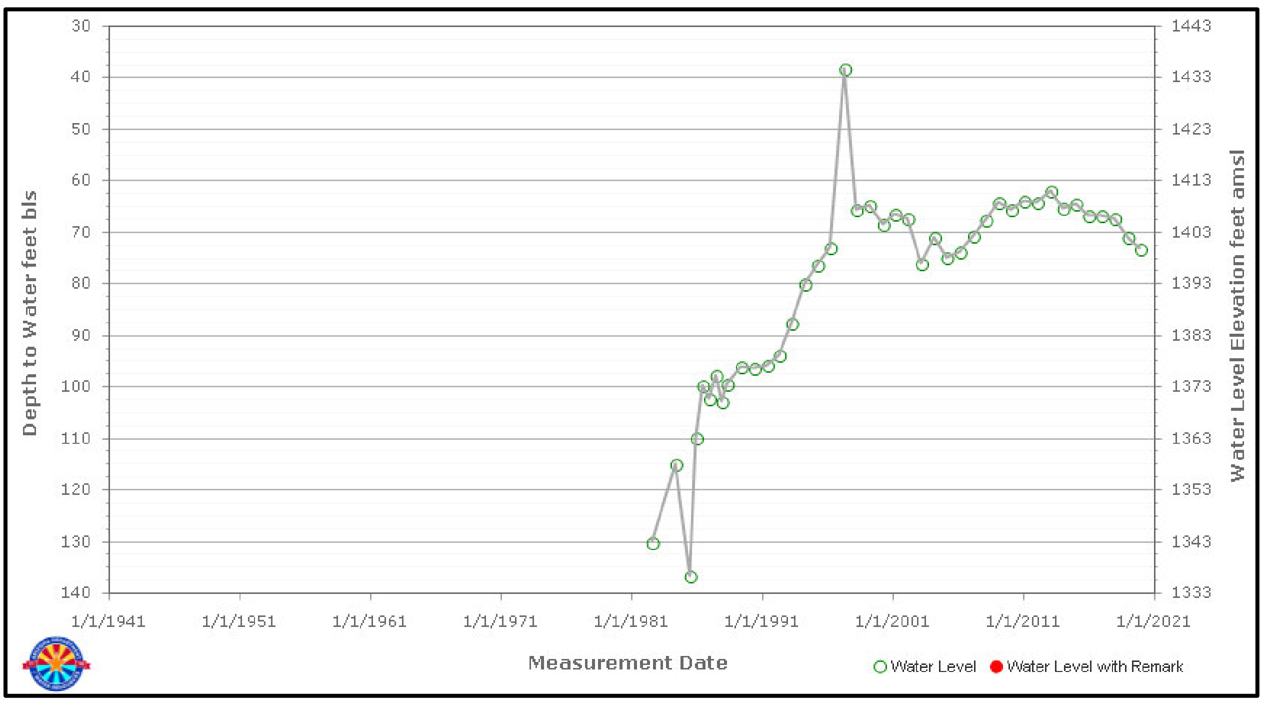
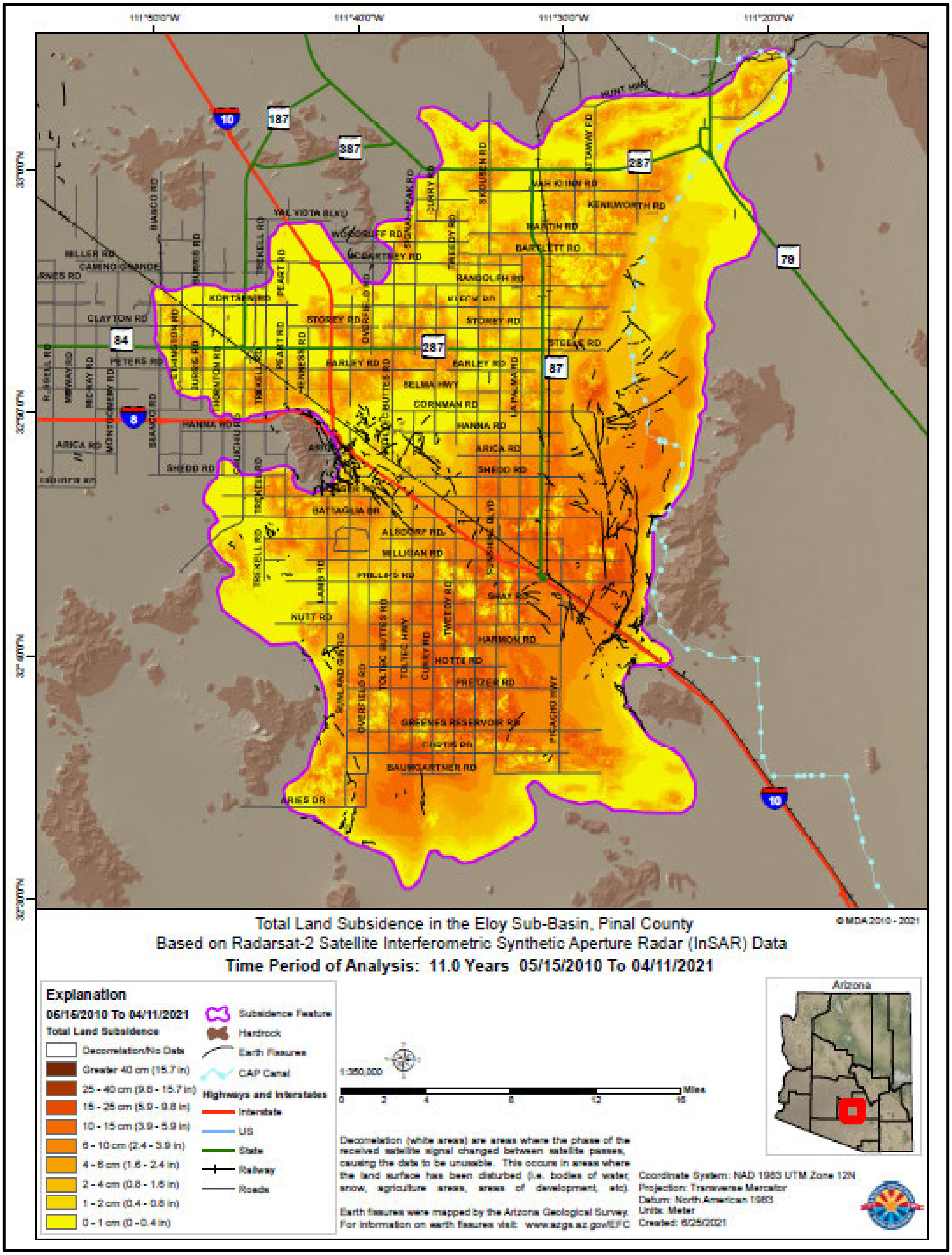


Figure B-2. Hydrograph of water levels in GWSI Well Site 325503111284801 (located approximately 1 mile east of the project area).

APPENDIX C

Land Subsidence Occurring in the Project Area Between 2010 and 2021


Total Land Subsidence in the Eloy Sub-Basin, Pinal County
Based on Radarsat-2 Satellite Interferometric Synthetic Aperture Radar (InSAR) Data
Time Period of Analysis: 11.0 Years 05/15/2010 To 04/11/2021
© MDA 2010 - 2021
Explanation
05/15/2010 To 04/11/2021
Total Land Subsidence
Decorrelation/No Data
Greater 40 cm (15.7 in)
25 - 40 cm (9.8 - 15.7 in)
15 - 25 cm (5.9 - 9.8 in)
10 - 15 cm (3.9 - 5.9 in)
6 - 10 cm (2.4 - 3.9 in)
4 - 6 cm (1.6 - 2.4 in)
2 - 4 cm (0.8 - 1.6 in)
1 - 2 cm (0.4 - 0.8 in)
0 - 1 cm (0 - 0.4 in)
Subsidence Feature
Hardrock
Earth Fissures
CAP Canal
Highways and Interstates
Interstate
US
State
Railway
Roads
1:350,000
Miles
Decorrelation (white areas) are areas where the phase of the received satellite signal changed between satellite passes, causing the data to be unusable. This occurs in areas where the land surface has been disturbed (i.e. bodies of water, snow, agriculture areas, areas of development, etc).
Earth fissures were mapped by the Arizona Geological Survey. For information on earth fissures visit: www.azgs.az.gov/EFC
Coordinate System: NAD 1983 UTM Zone 12N
Projection: Transverse Mercator
Datum: North American 1983
Units: Meter
Created: 6/25/2021
Arizona