5.1 Air Quality

5.1.1 Introduction

The Hidden Hills Solar Electric Generating System (HHSEGS) will be located on privately owned land in Inyo County, California, adjacent to the Nevada border. It will comprise two solar fields and associated facilities: the northern solar plant (Solar Plant 1) and the southern solar plant (Solar Plant 2). Each solar plant will generate 270 megawatts (MW) gross (250 MW net), for a total net output of 500 MW. Solar Plant 1 will occupy approximately 1,483 acres (or 2.3 square miles), and Solar Plant 2 will occupy approximately 1,510 acres (or 2.4 square miles). A 103-acre common area will be established on the southeastern corner of the site to accommodate an administration, warehouse, and maintenance complex, and an onsite switchyard. A temporary construction laydown and parking area on the west side of the site will occupy approximately 180 acres.

Each solar plant will use heliostats—elevated mirrors guided by a tracking system mounted on a pylon—to focus the sun's rays on a solar receiver steam generator (SRSG) atop a tower near the center of each solar field. The solar power tower technology for the HHSEGS project design incorporates an important technology advancement, the 750-foot-tall solar power tower. One principle advantage of the HHSEGS solar power tower design is that it results in more efficient land use and greater power generation. The new, higher, 750-foot solar power tower allows the heliostat rows to be placed closer together, with the mirrors at a steeper angle. This substantially reduces mirror shading and allows more heliostats to be placed per acre. More megawatts can be generated per acre and the design is more efficient overall.

In each solar plant, one Rankine-cycle steam turbine will receive steam from the SRSG (or solar boiler) to generate electricity. The solar field and power generation equipment will start each morning after sunrise and, unless augmented, will shut down when insolation drops below the level required to keep the turbine online. Each solar plant will include a natural-gas-fired auxiliary boiler, used to augment the solar operation when solar energy diminishes or during transient cloudy conditions, as well as a startup boiler, used during the morning startup cycle, and a nighttime preservation boiler, used to maintain system temperatures overnight. On an annual basis heat input from natural gas will be limited by fuel use and other conditions to less than 10 percent of the heat input from the sun.

To save water in the site's desert environment, each solar plant will use a dry-cooling condenser. Cooling will be provided by air-cooled condensers, supplemented by a partial dry-cooling system for auxiliary equipment cooling. Raw water will be drawn daily from onsite wells located in each power block and at the administration complex. Groundwater will be treated in an onsite treatment system for use as boiler make-up water and to wash the heliostats.

Two distinct transmission options are being considered because of a unique situation concerning Valley Electric Association (VEA). Under the first option, the project would interconnect via a 230-kilovolt (kV) transmission line to a new VEA-owned substation

(Tap Substation) at the intersection of Tecopa Road[1] and Nevada State Route (SR) 160 (the Tecopa/SR 160 Option). The other option is a 500-kV transmission line that interconnects to the electric grid at the Eldorado Substation (the Eldorado Option), in Boulder City, Nevada.

A 12- to 16-inch-diameter natural gas pipeline will be required for the project. It will exit the HHSEGS site at the California-Nevada border and travel on the Nevada side southeast along the state line, then northeast along Tecopa Road until it crosses under SR 160. From this location a 36-inch line will turn southeast and continue approximately 26 miles, following the proposed Eldorado Option transmission line corridor, to intersect with the Kern River Gas Transmission (KRGT) pipeline. A tap station will be constructed at that point to connect it to the KRGT line. The total length of the natural gas pipeline will be approximately 35.3 miles.

The transmission and natural gas pipeline alignments will be located in Nevada, primarily on federal land managed by the U.S. Bureau of Land Management (BLM), except for small segments of the transmission line (both options) in the vicinity of the Eldorado Substation, which is located within the city limits of Boulder City, Nevada. A detailed environmental impact analysis of the transmission and natural gas pipeline alignments will be prepared by BLM.

HHSEGS will include 10 natural-gas-fired boilers, ranging in size from 12 to 500 million British thermal units per hour (MMBtu/hr). Each of the two power blocks will include three 500 MMBTU/hr natural-gas-fired auxiliary boilers that will be used to augment the solar operation when solar energy diminishes or during transient cloudy conditions. The auxiliary boilers may also be used to extend daily power generation. However, on an annual basis heat input from natural gas will be limited by fuel use and other conditions to less than 10 percent of the heat input from the sun. Each power block will also include one 249 MMBtu/hr natural-gas-fired startup boiler that will be used during the morning startup cycle to assist the plant in coming up to operating temperature more quickly. Additionally, each solar plant will have one small 12 MMBtu/hr nighttime preservation boiler to maintain system temperatures overnight. Additional emitting units at each plant include an emergency diesel generator, a diesel fire pump engine, and a small wet-surface air cooler.

HHSEGS will not be a major stationary source under Great Basin Unified Air Pollution Control District (GBUAPCD) New Source Review (NSR) regulations because maximum facility emissions of each criteria pollutant will be below 250 pounds per day. The project will not be a major source under the federal Prevention of Significant Deterioration (PSD) program because its potential emissions will be than 100 tons per year (tpy) of each PSD criteria pollutant, and less than 100,000 tons per year of greenhouse gases (GHG).

This section describes existing air quality conditions; maximum potential impacts from the project; compliance with applicable laws, ordinances, regulations and standards (LORS); and mitigation measures that will keep maximum project impacts below applicable thresholds of significance. The methodology and results of the air quality analysis used to assess potential impacts are also presented. The analysis has been conducted according to

[1] The road is also called Tecopa Highway and Old Spanish Trail Highway. The names are generally used interchangeably.

the California Energy Commission (CEC) power plant siting requirements and also addresses GBUAPCD air permitting requirements.

HHSEGS will use the latest, most efficient generation technology to generate electricity in a manner that will minimize the amount of fuel needed, emissions of criteria pollutants, and potential effects on ambient air quality. Other beneficial environmental aspects of the project that avoid or minimize air quality impacts include the following:

- Use of solar technology to generate electricity with minimal use of fossil fuel
- Use of clean-burning natural gas for support equipment
- Low-sulfur content of the natural gas, which reduces sulfur dioxide (SO_2) emissions and subsequent sulfate fine particulate generation
- Optimized stack heights to reduce ground-level concentrations of exhaust pollutants below public health-related significance thresholds

Details of the air quality assessment of the project are contained in the following subsections:

- Section 5.1.2, Laws, Ordinances, Regulations, and Standards, describes applicable LORS pertaining to air quality aspects of the project.
- Section 5.1.3, Affected Environment, describes the local environment surrounding the project site, including topography, climate, and existing air quality. The most representative meteorological data—including wind speed and direction, temperature, relative humidity, and precipitation—and the most representative recent ambient concentration measurements for criteria air pollutants are summarized.
- Section 5.1.4, Environmental Analysis, evaluates the maximum potential air quality impacts due to the project's emissions of nitrogen oxides (NOx), carbon monoxide (CO), sulfur oxides (SOx), volatile organic compounds (VOCs), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). Emission estimates for these pollutants are presented for the construction phase of the project, as well as for operation of the installed equipment over a full range of operating modes, including commissioning, startups and shutdowns, maintenance activities, and normal operation with operable pollution control systems. A dispersion modeling analysis for nitrogen dioxide (NO_2), CO, SO_2, PM_{10}, and $PM_{2.5}$ is presented; the results show that the project would not cause or significantly contribute to exceedances of the California Ambient Air Quality Standards (CAAQS) or National Ambient Air Quality Standards (NAAQS). Emissions of GHGs from the project are also described.
- Section 5.1.5, Cumulative Air Quality Impacts, addresses the cumulative impacts of project emissions with other potential new sources of air pollution in the area around the project.
- Section 5.1.6, Consistency with Laws, Ordinances, Regulations, and Standards, describes how the project will comply with applicable LORS pertaining to air quality aspects of the project.
- Section 5.1.7, Mitigation Measures, describes mitigation for project air quality impacts.

- Section 5.1.8, Involved Agencies and Agency Contacts, lists the agency personnel contacted during preparation of the air quality assessment.
- Section 5.1.9, Permits Required and Permit Schedule, lists the air quality permits required for the project and provides a permit schedule for the project.
- Section 5.1.10, References, lists the references used to conduct the air quality assessment.

Additional air quality data are presented in other sections of this Application for Certification (AFC), including an evaluation of toxic air pollutants (see Section 5.9, Public Health) and information relating to the fuel characteristics, heat rate, and startup and operating limits of HHSEGS (see Section 2.0, Project Description).

5.1.2 Laws, Ordinances, Regulations, and Standards

Each level of government—federal, state, and local—has adopted specific regulations that regulate emissions from stationary sources, several of which are applicable to this project. Each of these regulatory programs is discussed in the following sections.

5.1.2.1 Federal LORS

The U.S. Environmental Protection Agency (EPA) implements and enforces the requirements of many of the federal environmental laws. The federal Clean Air Act, as most recently amended in 1990, provides EPA with the legal authority to regulate air pollution from stationary sources such as the project. EPA has promulgated the following stationary source regulatory programs to implement the requirements of the 1990 Clean Air Act:

- Prevention of Significant Deterioration
- New Source Review
- Standards of Performance for New Stationary Sources (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAPS)
- Title IV: Acid Deposition Control
- Title V: Operating Permits

5.1.2.1.1 Prevention of Significant Deterioration Program

Authority: Clean Air Act §160-169A, 42 USC §7470-7491; 40 CFR Parts 51 and 52

Requirements: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. PSD applies to pollutants for which ambient concentrations do not exceed the corresponding NAAQS (i.e., attainment pollutants). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., national parks and wilderness areas).

The PSD requirements apply to any project that is a new major stationary source or a major modification to an existing major stationary source. A major source is a listed facility (one of 28 PSD source categories listed in the federal Clean Air Act) that emits at least 100 tpy of any criteria pollutant, or any other facility that emits at least 250 tpy. Effective July 1, 2011, a stationary source that emits both more than 100,000 tpy of GHGs and more than 100 tpy of any individual GHG, is also considered to be a major stationary source. A major modification is any project at a major stationary source that results in a significant increase in emissions of any PSD pollutant. A PSD pollutant is a criteria pollutant for which the area is in attainment with the NAAQS.

A significant increase for a PSD pollutant is an increase above the significant emission rate for that pollutant (Table 5.1-1). It is important to note that, once PSD is triggered by any pollutant, PSD requirements apply to any PSD pollutant with an emission increase above the significance level, regardless of whether the facility is major for that pollutant.

TABLE 5.1-1
PSD Significant Emission Thresholds

Pollutant	PSD Significant Emission Threshold (tpy)[a]
NOx	40
SO_2	40
CO	100
VOC	40
PM_{10}	15
$PM_{2.5}$	10
Lead	0.6
GHG[b]	75,000

[a]40 CFR 52.21 (b)(1)(23).

[b]PSD/Title V GHG Tailoring Rule, June 3, 2010.

The principal requirements for the PSD program include those outlined below.

- Pre- and/or postconstruction air quality monitoring may be required.
- Emissions of the PSD pollutants that are subject to PSD review must be controlled using best available control technology (BACT).
- Air quality impacts in combination with other increment-consuming sources must not exceed maximum allowable incremental increases. Air quality impacts of all sources in the area plus ambient pollutant background levels cannot exceed NAAQS.
- The air quality impacts nearby PSD Class I areas (specific national parks and wilderness areas) must be evaluated.
- The air quality impacts on growth, visibility, soils and vegetation must be evaluated.

Air Quality Monitoring

At its discretion, EPA may require preconstruction and/or postconstruction ambient air quality monitoring for PSD sources if representative monitoring data are not already available. Preconstruction monitoring data must be gathered over a one-year period to characterize local ambient air quality. Postconstruction air quality monitoring data must be collected as deemed necessary by EPA to characterize the impacts of proposed project emissions on ambient air quality.

Best Available Control Technology

BACT must be applied to any new or modified major source to minimize the emissions increase of those pollutants exceeding the PSD emission thresholds. EPA defines BACT as an emissions limitation based on the maximum degree of reduction for each subject pollutant—considering energy, environmental, and economic impacts—that is achievable through the application of available methods, systems, and techniques. BACT must be as stringent as any emission limit required by an applicable NSPS or NESHAP.

Air Quality Impact Analysis

An air quality dispersion analysis must be conducted to evaluate impacts of significant emission increases from new or modified facilities on ambient air quality. PSD source emissions must not cause or contribute to an exceedance of any ambient air quality standard, and the increase in ambient air concentrations must not exceed the allowable increments shown in Table 5.1-2. Once PSD review is triggered for a project, all pollutants with emission increases above the PSD significance thresholds are subject to this requirement.

TABLE 5.1-2
PSD Increments and Significant Impact Levels

Pollutant	Averaging Time	SILs ($\mu g/m^3$)[a]	Maximum Allowable Class II Increments[b]
NO_2	Annual	1.0	25
	1-hr	7.53[c]	No 1-hr increment
SO_2	Annual	1.0	20
	24-hr	5	91
	3-hr	25	512
	1-hr	7.83[c]	No 1-hr increment
CO	8-hr	500	No CO increments
	1-hr	2,000	
PM_{10}	Annual	1.0	17
	24-hr	5	30
$PM_{2.5}$	Annual	0.3	4
	24-hr	1.2	9

[a]40 CFR 51.165 (b)(2).

[b]40 CFR 52.21 (c)

[c]EPA has not yet defined significance impact levels (SILs) for one-hour NO_2 or SO_2 impacts. However, EPA has suggested that, until SILs have been promulgated, interim values of 4 ppb (7.53 $\mu g/m^3$) for NO_2 and 3 ppb (7.83 $\mu g/m^3$) for SO_2 may be used. These values will be used in this analysis wherever a SIL would be used for NO_2 or SO_2.

$\mu g/m^3$ = micrograms per cubic meter

Protection of Class I Areas

The potential increase in ambient air quality concentrations for attainment pollutants within Class I areas closer than approximately 100 km may need to be quantified if the new or modified PSD source were to have a sufficiently large emission increase as evaluated by the Class I area Federal Land Managers. In such a case, a Class I visibility impact analysis would also be performed.

Growth, Visibility, Soils, and Vegetation Impacts

Impairment to visibility, soils, and vegetation resulting from PSD source emissions as well as associated commercial, residential, industrial, and other growth must be analyzed. This analysis includes cumulative impacts to local ambient air quality.

Administering Agency: EPA.

5.1.2.1.2 Nonattainment New Source Review

Authority: Clean Air Act §171-193, 42 USC §7501 et seq.; 40 CFR Parts 51 and 52

Requirement: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of ambient quality standards. In general, this program is implemented at the local level with EPA oversight.

- Emissions must be controlled to the lowest achievable emission rate (LAER).
- Sufficient offsetting emissions reductions must be obtained following the requirements in the regulations to continue reasonable further progress toward attainment of applicable NAAQS.
- The owner or operator of the new facility must confirm that major stationary sources owned or operated by the same entity in California are in compliance or on schedule for compliance with applicable emissions limitations in this rule.
- The administrator must find that the implementation plan has been adequately implemented.
- An analysis of alternatives must show that the benefits of the proposed source significantly outweigh any environmental and social costs.

Nonattainment new source review jurisdiction has been delegated to the GBUAPCD for all pollutants and is discussed further under local LORS section below.

Administering Agency: GBUAPCD, with EPA oversight.

5.1.2.1.3 New Source Performance Standards

Authority: Clean Air Act §111, 42 USC §7411; 40 CFR Part 60

Requirements: Establishes national standards of performance to limit the emissions of criteria pollutants (air pollutants for which EPA has established NAAQS) from new or reconstructed facilities in specific source categories. Applicability of these regulations depends on equipment size, process rate, and date of construction. HHSEGS will be subject to the following NSPS:

Standards of Performance for Electric Utility Steam Generating Units

The requirements of Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, are applicable to the auxiliary boilers. For natural-gas-fired units, Subpart Da includes the following emission limits:

- NOx: 0.20 lb/MMBtu (30-day average)
- SO_2: 1.4 lb/MWh (30-day average)
- PM: 0.015 lb/MMBtu

Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

The requirements of Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, are applicable to the startup boilers. For natural-gas-fired units, Subpart Db includes the following emission limits:

- NOx: 0.20 lb/MMBtu (24-hour average basis)
- SO_2: 0.20 lb/MMBtu

Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

The requirements of Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, are applicable to the nighttime preservation boilers. For these small natural-gas-fired units, Subpart Dc includes the following emission limit:

- SO_2: 0.5 lb/MMBtu

The PM limits of Subpart Dc do not apply to boilers with a heat input capacity below 30 MMBtu/hr, such as the nighttime preservation boilers.

Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, will be applicable to the emergency engines and the fire pump engines. Further discussion of the applicability of these regulations is included in the Section 5.1.6.

All of these standards are enforced at the local level with federal and state oversight.

Administering Agency: GBUAPCD, with EPA and California Air Resources Board oversight.

5.1.2.1.4 National Emission Standards for Hazardous Air Pollutants

Authority: Clean Air Act §112, 42 USC §7412

Requirements: Establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established) from facilities in specific source categories. These standards are implemented at the local level with federal oversight.

National Emission Standards for Reciprocating Internal Combustion Engines

The requirements of 40 CFR 63 Subpart ZZZZ (National Emission Standards for Reciprocating Internal Combustion Engines) will apply to the emergency compression-ignition engines that are part of the project. For emergency engines in this size range, compliance with the requirements of Subpart ZZZZ is achieved by purchasing engines that comply with the applicable NSPS (40 CFR 60 Subpart IIII).

National Emission Standards for Area Sources: Industrial/ Commercial/Institutional Boilers
40 CFR 63 Subpart JJJJJJ (National Emission Standards for Area Sources: Industrial/ Commercial/Institutional Boilers) does not include requirements for natural-gas-fired boilers, so this regulation will not apply to the any of the boilers at HHSEGS.

Administering Agency: GBUAPCD, with EPA oversight.

5.1.2.1.5 Acid Rain Program

Authority: Clean Air Act §401 (Title IV), 42 USC §7651

Requirement: Requires the monitoring and reporting of emissions of acidic compounds and their precursors from combustion power generating equipment larger than 25 MW. The principal source of these compounds is the combustion of fossil fuels. Therefore, Title IV established national standards to monitor, record, and, in some cases, limit SO_2 and NOx emissions from electrical power generating facilities. These standards are implemented at the local level with federal oversight. GBUAPCD has received delegation authority to implement Title IV.

Administering Agency: GBUAPCD, with EPA oversight.

5.1.2.1.6 Title V Operating Permits Program

Authority: Clean Air Act §501 (Title V), 42 USC §7661

Requirements: Requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, Phase II acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. GBUAPCD has received delegation authority for this program.

Administering Agency: GBUAPCD, with EPA oversight.

5.1.2.2 State LORS: California

The California Air Resources Board (CARB) was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update, as necessary, the state's ambient air quality standards; to review the operations of the local air pollution control districts; and to review and coordinate preparation of the SIP for achievement of the federal ambient air quality standards. CARB has implemented the following state or federal stationary source regulatory programs in accordance with the requirements of the federal Clean Air Act and California Health & Safety Code (H&SC):

- State Implementation Plan
- California Clean Air Act
- Nuisance Regulation
- Toxic Air Contaminant Program

- Air Toxics "Hot Spots" Act
- CEC and CARB Memorandum of Understanding
- California Climate Change Regulatory Program

5.1.2.2.1 State Implementation Plan

Authority: H&SC §39500 et seq.

Requirements: Required by the federal Clean Air Act, the SIP must demonstrate the means by which all areas of the state will attain and maintain NAAQS within the federally mandated deadlines. CARB reviews and coordinates preparation of the SIP. Local districts must adopt new rules (and/or revise existing rules) and demonstrate that the resulting emission reductions, in conjunction with reductions in mobile source emissions, will result in the attainment of NAAQS. The relevant GBUAPCD Rules and Regulations that have also been incorporated into the SIP are discussed with the local LORS.

Administering Agency: GBUAPCD, with CARB and EPA oversight.

5.1.2.2.2 California Clean Air Act

Authority: H&SC §40910 − 40930

Requirements: Established in 1989, the California Clean Air Act requires local districts to attain and maintain both national and state ambient air quality standards at the "earliest practicable date." Local districts must prepare air quality plans demonstrating the means by which the ambient air quality standards will be attained and maintained.

Administering Agency: GBUAPCD, with CARB oversight.

5.1.2.2.3 Nuisance Regulation

Authority: H&SC §41700

Requirements: Provides that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property."

Administering Agency: GBUAPCD and CARB

5.1.2.2.4 Toxic Air Contaminant Program

Authority: H&SC §39650 − 39675

Requirements: Established in 1983, the Toxic Air Contaminant Identification and Control Act created a two-step process to identify toxic air contaminants and control their emissions. CARB identifies and prioritizes the pollutants to be considered for identification as toxic air contaminants, and also assesses the potential for human exposure to a substance; the Office of Environmental Health Hazard Assessment (OEHHA) evaluates the corresponding health effects. Both agencies collaborate in the preparation of a risk assessment report, which concludes whether a substance poses a significant health risk and should be identified as a toxic air contaminant. In 1993, the Legislature amended the program to identify the 187 federal hazardous air pollutants as toxic air contaminants. CARB reviews the emission sources of an identified toxic air contaminant and, if necessary, develops air toxics control measures to reduce the emissions.

Administering Agency: GBUAPCD and CARB

5.1.2.2.5 Air Toxic "Hot Spots" Act

Authority: H& SC §44300-44384; 17 California Code of Regulations (CCR) §93300-93347

Requirements: Established in 1987, the Air Toxics "Hot Spots" Information and Assessment Act (also known as AB 2588) supplements the toxic air contaminant program, by requiring the development of a statewide inventory of air toxics emissions from stationary sources. The program requires affected facilities to prepare (1) an emissions inventory plan that identifies relevant air toxics and sources of air toxics emissions; (2) an emissions inventory report quantifying air toxics emissions; and (3) a health risk assessment, if necessary, to characterize the health risks to the exposed public. Facilities whose air toxics emissions are deemed to pose a significant health risk must issue notices to the exposed population. In 1992, the Legislature amended the program to further require facilities whose air toxics emissions are deemed to pose a significant health risk to implement risk management plans to reduce the associated health risks. This program is implemented at the local level with state oversight.

Administering Agency: GBUAPCD and CARB

5.1.2.2.6 CEC and CARB Memorandum of Understanding

Authority: CA Pub. Res. Code §25523(a); 20 CCR §1752, 1752.5, 2300-2309 and Div. 2, Chap. 5, Appendix B, Part (g)(8)(K)

Requirements: Provides for the inclusion of air district permit requirements in the CEC's decision on an application for certification to assure protection of environmental quality. The AFC is required to include information concerning air quality protection.

Administering Agency: CEC

5.1.2.2.7 California Climate Change Regulatory Program

Authority: Stats. 2006, Ch. 488 and H&SC § 38500-38599

Requirements: The State of California adopted the Global Warming Solutions Act of 2006 (Assembly Bill [AB] 32) on September 27, 2006, which requires sources within the state to reduce carbon emissions to 1990 levels by the year 2020.

AB 32 set the following milestone dates for CARB to take specific actions:

- June 30, 2007: Identify a list of discrete early action GHG emission reduction measures (first report published April 20, 2007, with additional measures adopted on October 25, 2007).
- January 1, 2008: Establish a statewide GHG emission cap for 2020 that is equivalent to 1990 emissions.
- January 1, 2008: Adopt mandatory reporting rules for significant sources of GHGs.

- January 1, 2009: Adopt a scoping plan that will indicate how GHG emission reductions will be achieved from significant GHG sources through regulations, market-based compliance mechanisms, and other actions, including recommendation of a de minimis threshold for GHG emissions, below which sources would be exempt from reduction requirements.
- January 1, 2011: Adopt regulations to achieve maximum technologically feasible and cost-effective GHG emission reductions, including provisions for both market-based and alternative compliance mechanisms.
- January 1, 2012: Regulations adopted prior to January 1, 2010, become effective.

Specific actions taken by CARB that relate to power plants and other industrial facilities include the establishment of GHG monitoring and reporting requirements, and the adoption of a cap-and-trade program for GHG emissions. The latter program is currently undergoing legal challenge.

On January 25, 2007, the PUC and CEC jointly adopted an interim Greenhouse Gas Emissions Performance Standard (EPS) in an effort to help mitigate the effects of climate change. The EPS is a facility-based emissions standard requiring that all new long-term commitments for base load generation to serve California consumers be with power plants that have emissions no greater than a combined-cycle gas turbine plant. That level is established at 1,100 pounds of CO_2 per megawatt-hour.

The AFC is required to include the project's emission rates of greenhouse gases (CO_2, CH_4, N_2O, and SF_6) from combustion sources, cooling towers, fuels and materials handling processes, delivery and storage systems, and from all onsite secondary emission sources. The required information is presented below.

Administering Agencies: CARB, PUC and CEC.

5.1.2.3 Local LORS: California

When the state's air pollution statutes were reorganized in the mid-1960s, local air pollution control districts (APCDs) were required to be established in each county of the state (H&SC §4000 et seq.). There are three different types of districts: county, regional, and unified. In addition, special air quality management districts (AQMDs), with more comprehensive authority over non-vehicular sources as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California, (H&SC §40200 et seq.).

Air pollution control districts and air quality management districts in California have principal responsibility for:

- Developing plans for meeting the state and federal ambient air quality standards;
- Developing control measures for non-vehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards;
- Implementing permit programs established for the construction, modification, and operation of sources of air pollution; and

- Enforcing air pollution statutes and regulations governing non-vehicular sources, and for developing employer-based trip reduction programs.

5.1.2.3.1 Great Basin Unified Air Pollution Control District Rules and Regulations

Authority: CA Health & Safety Code §40001

Requirements: Prohibit emissions and other discharges (such as smoke and odors) from specific sources of air pollution in excess of specified levels.

Administering Agency: GBUAPCD, with CARB oversight.

Permits Required

Under Regulation II, Rule 200 (Permits Required) and Rule 209-A, section E (Power Plants), GBUAPCD administers the air quality regulatory program for the construction, alteration, replacement, and operation of new power plants. As part of the AFC process, the project will be required to obtain a preconstruction Determination of Compliance (DOC) from the GBUAPCD. Regulation II, Rule 200 incorporates other GBUAPCD rules that govern how sources may emit air contaminants through the issuance of air permits (i.e., Authority to Construct [ATC] and Permit to Operate [PTO]). This permitting process allows the GBUAPCD to review new and modified air pollution sources to ensure compliance with all applicable prohibitory rules and to ensure that appropriate emission controls are used. Projects that are reviewed under the CEC AFC process must obtain a final DOC (FDOC) from the local air district prior to construction of the new power plant. Upon approval of the AFC by the CEC with conditions incorporating the requirements of the FDOC, the FDOC will confer upon the applicant all of the rights and privileges of an ATC. Once the project commences operations and demonstrates compliance with the ATC, GBUAPCD will issue a PTO. The PTO specifies conditions that the facility must meet to comply with all applicable air quality rules, regulations, and standards.

An application for a Determination of Compliance will be filed with GBUAPCD at approximately the same time as the AFC is filed with the CEC.

New Source Review Requirements

There are three basic requirements within the NSR rules. First, BACT and/or LAER requirements must be applied to any new source with potential emissions above specified threshold quantities. Second, all potential emission increases of nonattainment pollutants or precursors from the proposed source above specified thresholds must be offset by real, quantifiable, surplus, permanent, and enforceable emission decreases in the form of ERCs. Third, an ambient air quality impact analysis must be conducted to confirm that the project does not cause or contribute to a violation of a national or California AAQS or jeopardize public health.

The first two of these three NSR provisions (BACT and emission offset requirements) are included in GBUAPCD's Regulation II, Rule 209-A, section D. The third NSR provision (to confirm via a modeling analysis that the project does not cause or contribute to a violation of applicable air quality or public health standards) is included in Regulation II, Rule 216.

New Source Review Requirements for Air Toxics

The GBUAPCD's NSR rule for air toxics (Regulation II, Rule 220, Construction or Reconstruction of Major Sources of Hazardous Air Pollutants) describes the requirements, procedures, and standards for evaluating the potential impact of toxic air contaminants (TACs) from new sources and modifications to existing sources.

New Source Performance Standards

The GBUAPCD's New Source Performance Standards (Regulation IX, New Source Performance Standards) incorporate the federal NSPS from 40 CFR Part 60. The applicability and requirements of the New Source Performance Standards are discussed above under the federal regulations section.

Federal Programs and Permits

The federal Title IV acid rain program requirement and Title V operational permit requirements are in GBUAPCD's Rule 217 (Additional Procedures for Issuing Permits to Operate for Sources Subject to Title V of the Federal Clean Air Act Amendments of 1990). The applicability and requirements of these programs and permits are discussed above under the federal regulations section.

Public Notification

If project emissions exceed the air quality impact assessment (AQIA) trigger levels, public notice under Rule 209-A is required. The Applicant expects that the GBUAPCD Air Pollution Control Officer will provide this notice in a timely manner. The AQIA trigger levels for new sources are 15 pounds per hour or 150 pounds per day of NOx, VOC, SOx, PM_{10} or $PM_{2.5}$, and 150 pounds per hour or 1,500 pounds per day of CO.

Permit Fees

The GBUAPCD requirements regarding permit fees are specified in Regulation III. This regulation establishes the filing and permit review fees for specific types of new sources, as well as annual renewal fees and penalty fees for existing sources.

Prohibitions

The GBUAPCD prohibitions for specific types of sources and pollutants are addressed in Regulation IV. The prohibitory rules that potentially apply to the project are listed below.

Rule 400 – Visible Emissions: This rule prohibits any source from discharging emissions of any air contaminant that is darker in shade than that designated as Number 1 on the Ringelmann Chart for a period or periods aggregating more than 3 minutes in any period of 60 consecutive minutes.

Rule 401 – Fugitive Dust: This rule requires that reasonable precautions be taken to prevent visible particulate matter from being airborne. Examples of reasonable precautions include proper roadway maintenance; the use (where practical) of hoods, fans, and filters; and the use of water or chemicals to control dust from demolition, construction, road grading, or clearing of land.

Rule 402 – Nuisance: This rule prohibits the discharge from a facility of air contaminants that cause injury, detriment, nuisance, or annoyance to the public, or cause damage to business or property.

Rule 404-A – Particulate Matter Emission Standards: This rule prohibits the discharge from any source of particulate matter in excess of 0.30 grain per dry standard cubic foot (0.67 grams per dry standard cubic meter) of gas.

Rule 404-B – Oxides of Nitrogen: This rule applies to fuel-burning equipment with a maximum heat input rate in excess of 1.5 billion Btu/hr (gross) (1500 MMBtu/hr HHV). All of the fuel burning equipment proposed for installation at HHSEGS has a maximum heat input rate below this threshold, so this rule is not applicable to the project.

Rule 416 – Sulfur Compounds and Nitrogen Oxides: This rule prohibits emissions from a single source in excess of the following:

- Sulfur compounds as SO_2: 0.2% by volume
- NOx, calculated as NO_2: 140 lb/hr from any new boiler

5.1.2.3.2 Inyo County Renewable Energy Ordinance

For projects not subject to the CEC's exclusive jurisdiction, the Inyo County Renewable Energy Ordinance requires developers of renewable energy projects to apply for and obtain from the County Planning Commission a renewable energy impact determination that identifies environmental and other impacts expected to result from such project and mitigation for those impacts. The identification of potential air quality impacts and mitigation required by the Renewable Energy Ordinance is provided in this AFC.

All applicable LORS are summarized in Table 5.1-3.

TABLE 5.1-3
Laws, Ordinances, Regulations, and Standards Applicable to Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	AFC Section Explaining Conformance
Federal					
Clean Air Act (CAA) §160-169A and implementing regulations, Title 42 United States Code (USC) §7470-7491 (42 USC 7470-7491), Title 40 Code of Federal Regulations (CFR) Parts 51 & 52 (40 CFR 51 & 52) (Prevention of Significant Deterioration Program)	Requires PSD review and facility permitting for construction of new or modified major stationary sources of air pollution. PSD review applies to pollutants for which ambient concentrations are not greater than NAAQS.	EPA	PSD Permit with conditions limiting emissions	Agency approval to be obtained before start of construction	5.1.6.1
CAA §171-193, 42 USC §7501 et seq. (New Source Review)	Requires NSR facility permitting for construction or modification of specified stationary sources. NSR applies to pollutants for which ambient concentrations are higher than NAAQS.	GBUAPCD with EPA oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.1
CAA §401 (Title IV), 42 USC §7651 (Acid Rain Program)	Requires quantification of NO_2 and SO_2 emissions, and requires operator to hold allowances.	GBUAPCD with EPA oversight	Acid Rain permit	Application to be submitted 18 months prior to start of operation.	5.1.6.1
CAA §501 (Title V), 42 USC §7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	GBUAPCD with EPA oversight	Title V permit	Application to be submitted 12 months after start of operation.	5.1.6.1
CAA §111, 42 USC §7411, 40 CFR Part 60 (NSPS)	Establishes national standards of performance for new stationary sources.	GBUAPCD with EPA oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.1

TABLE 5.1-3
Laws, Ordinances, Regulations, and Standards Applicable to Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	AFC Section Explaining Conformance
CAA §112, 42 USC §7412, 40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants [NESHAPs])	Establishes national emission standards for hazardous air pollutants.	GBUAPCD with EPA oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.1
State					
California Health & Safety Code (H&SC) §41700 (Nuisance Regulation)	Prohibits discharge of such quantities of air contaminants that cause injury, detriment, nuisance, or annoyance.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.2
H&SC §44300-44384; CCR §93300-93347 (Toxic “Hot Spots” Act)	Requires preparation and biennial updating of facility emission inventory of hazardous substances; risk assessments.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.2
California Public Resources Code §25523(a); 20 CCR §1752, 2300-2309 (CEC/CARB Memorandum of Understanding)	Requires that CEC’s decision on AFC include requirements to assure protection of environmental quality; AFC required to address air quality protection.	CEC	CEC Conditions of Certification that include the conditions in the FDOC.	Agency approval to be obtained before start of construction	5.1.6.2
Global Warming Solutions Act and other GHG reduction measures	Reduce emissions of GHGs; operator must purchase and surrender GHG allowances.	CEC and CARB	CEC Conditions of certification requiring reporting of GHG emissions and compliance with ARB program requirements.	Agency approval to be obtained before start of construction	5.1.6.2
Local					
California Health & Safety Code (H&SC) §40001 (Air pollution–general)	Prohibits emissions and other discharges (such as smoke and odors) from specific sources of air pollution in excess of specified levels.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3

TABLE 5.1-3
Laws, Ordinances, Regulations, and Standards Applicable to Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	AFC Section Explaining Conformance
GBUAPCD Regulation II, Rule 200 (Permits required) and Rule 209-A.E (Power Plants)	Administers air quality regulation program for power plants.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Regulation II, Rules 209-A.D and 216 (New Source Review)	Establishes criteria for siting new and modified emission sources.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Regulation II, Rule 220 (Construction or Reconstruction of Major Sources of HAPs)	Establishes procedures for review and control of toxic air contaminants from new sources.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Regulation IX, New Source Performance Standards	Incorporates federal NSPS standards.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Rule 217 (Federal permits)	Implements Acid Rain and Title V permit programs.	GBUAPCD with EPA oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Rule 209-A	Public Notification Requirement	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Regulation III (Permit Fees)	Permit fees	GBUAPCD		Payment of fees required at time of application	5.1.6.3

TABLE 5.1-3
Laws, Ordinances, Regulations, and Standards Applicable to Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	AFC Section Explaining Conformance
GBUAPCD Rule 400 (Visible Emissions)	Prohibits visible emissions above certain levels.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Rule 401 (Fugitive Dust)	Requires that reasonable precautions be taken to prevent visible particulate matter from being airborne.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Rule 402 (Nuisance)	Prohibits emissions and other discharges (such as smoke and odors) from specific sources of air pollution in excess of specified levels.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Rule 404-A (Particulate Matter)	Limits emissions of particulate matter.	GBUAPCD with CARB oversight	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3
GBUAPCD Rule 416 (Sulfur Compounds and Nitrogen Oxides)	Limits NO_x and SO_2 emissions from combustion sources.	GBUAPCD	FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction	5.1.6.3

5.1.3 Affected Environment

This section describes the regional climate and meteorological conditions that influence the transport and dispersion of air pollutants, as well as the existing air quality within the project region. The data presented in this section are representative of the project site.

The project site is located in the southeastern corner of Inyo County, California. The approximately 3,277-acre site is roughly triangular-shaped, and is bordered on the south by Tecopa Road and on the northeast by the California/Nevada border. The southwest corner of the site is at latitude and longitude 36.01526°N and -115.91270°W, respectively.

5.1.3.1 Geography and Topography

The project site is on the edge of Nevada's southwestern plateau at approximately 2,600 feet above mean sea level, approximately 45 miles west of Las Vegas. The project site is generally flat, and lies in a valley located between the Spring Mountain range to the east (highpoint: Charleston Peak at 11,918 feet above sea level), and the Nopah Mountains to the west (highpoint: Nopah Point at over 6,394 feet above mean sea level).

5.1.3.2 Meteorology and Climate

Consistent with the typical weather of a high desert climate, southeastern Inyo County is generally characterized by low precipitation, hot summers, and cold winters. Daytime temperatures during the summer months often reach into the 100s, although gentle breezes, extremely low humidity, and the relatively high elevation combine to keep nighttime temperatures down to the 70s and low 80s. Spring and fall temperatures range from the 60s in March to the 80s and 90s in May. Temperatures in September are usually in the 90s and drop off to the 60s by late November. Winter nights are usually cold, with temperatures dropping to the 30s for short periods. Daytime temperatures are typically in the 50s, with clear skies. The mountain ranges surrounding the area also have a major influence on climate, serving as a meteorological boundary that effectively removes moisture from the air flowing into the valley.

The nearest full-time meteorological monitoring station to the project site is maintained by the National Weather Service Cooperative Network and is located at Pahrump, on SR 160 at the southern tip of Nye County, Nevada—at latitude 35°16'N, longitude 115°59'W. Based on 97 years of data collection (1914–2010), the annual average temperature measured in the area is 61.8 degrees Fahrenheit (°F). The hottest month, July, has an average maximum temperature of 101.6°F and an average minimum temperature of 67.3°F. The coldest month, December, has an average maximum temperature of 57.9°F and an average minimum temperature of 26.6°F.

Monthly mean precipitation at Pahrump ranges from 0.84 inches in February to 0.09 inches in June. The average annual precipitation in the project area is about 4.7 inches, half of which falls from December through March. Relative humidity levels are low, with relative humidity averaging about 29% annually. Long-term average temperature and precipitation data are summarized in Table 5.1-4.

TABLE 5.1-4
Average Temperatures and Precipitation in Pahrump, NV (1914-2010)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Average Maximum Temperature (°F)	57.3	62.5	68.0	75.5	85.2	95.2	101.6	99.8	92.6	81.5	67.5	57.9	78.7
Average Minimum Temperature (°F)	26.9	32.0	36.8	43.1	52.1	59.9	67.3	65.5	56.7	44.7	33.8	26.6	45.5
Precipitation (inches)	0.66	0.84	0.55	0.31	0.2	0.09	0.31	0.32	0.34	0.23	0.37	0.5	4.7

Source: Western Regional Climate Center (http://www.wrcc.dri.edu/cgi-bin/cliMAIN.pl?nv5890)

At the Pahrump station, the prevailing wind direction is from the south through southeast, and the average wind speed is 2.1 meters per second. Winds are typically of light to moderate strength. Composite annual and quarterly wind roses are shown in Figures 5.1-1 through 5.1-5 (figures are provided at the end of this section). Individual annual and quarterly wind roses and quarterly wind frequency distributions for the project area are provided in Appendix 5.1A.

5.1.3.3 Overview of Air Quality Standards

EPA has established NAAQS for ozone, NO_2, CO, SO_2, PM_{10}, $PM_{2.5}$, and airborne lead. Areas with ambient levels above these standards are designated by EPA as "nonattainment areas" subject to planning and pollution control requirements that are more stringent than standard requirements.

CARB has established California ambient air quality standards for ozone, CO, NO_2, SO_2, sulfates, PM_{10}, $PM_{2.5}$, airborne lead, hydrogen sulfide, and vinyl chloride at levels designed to protect the most sensitive members of the population, particularly children, the elderly, and people who suffer from lung or heart diseases.

Both state and national air quality standards consist of two parts: an allowable concentration of a pollutant, and an averaging time over which the concentration is to be measured. Allowable concentrations are based on the results of studies of the effects of the pollutants on human health, crops and vegetation, and, in some cases, damage to paint and other materials. The averaging times are based on whether the damage caused by the pollutant is more likely to occur during exposures to a high concentration for a short time (one hour, for instance), or to a relatively lower average concentration over a longer period (8 hours, 24 hours, or 1 month). For some pollutants there is more than one air quality standard, reflecting both short-term and long-term effects. Table 5.1-5 presents the NAAQS and California ambient air quality standards for selected pollutants. The California standards are generally set at concentrations lower than the federal standards and, in some cases, have shorter averaging periods.

TABLE 5.1-5
National and California Ambient Air Quality Standards

Averaging Time	Averaging Time	California Standards		Federal Standards		
		Concentration	Method	Primary	Secondary	Method
Ozone	1 Hour	0.09 ppm ($180\ \mu g/m^3$)	Ultraviolet Photometry	—	Same as Primary Standard	Ultraviolet Photometry
	8 Hour	0.07 ppm ($137\ \mu g/m^3$)		0.075 ppm ($147\ \mu g/m^3$)		
Respirable Particulate Matter (PM_{10})	24 Hour	$50\ \mu g/m^3$	Gravimetric or Beta Attenuation	$150\ \mu g/m^3$	Same as Primary Standard	Inertial Separation and Gravimetric Analysis
	Annual Arithmetic Mean	$20\ \mu g/m^3$		—		
Fine Particulate Matter ($PM_{2.5}$)	24 Hour	No Separate State Standard		$35\ \mu g/m^3$ a	Same as Primary Standard	Inertial Separation and Gravimetric Analysis
	Annual Arithmetic Mean	$12\ \mu g/m^3$	Gravimetric or Beta Attenuation	$15.0\ \mu g/m^3$		
Carbon Monoxide (CO)	8 Hour	9.0 ppm ($10\ mg/m^3$)	Non-Dispersive Infrared Photometry (NDIR)	9 ppm ($10\ mg/m^3$)	None	Non-Dispersive Infrared Photometry (NDIR)
	1 Hour	20 ppm ($23\ mg/m^3$)		35 ppm ($40\ mg/m^3$)		
Nitrogen Dioxide (NO_2)	Annual Arithmetic Mean	0.030 ppm ($57\ \mu g/m^3$)	Gas Phase Chem-iluminescence	53 ppb ($100\ \mu g/m^3$)	Same as Primary Standard	Gas Phase Chem-iluminescence
	1 Hour	0.18 ppm ($339\ \mu g/m^3$)		100 ppb [b] ($188\ \mu g/m^3$)	None	
Sulfur Dioxide (SO_2)	24 Hour	0.04 ppm ($105\ \mu g/m^3$)	Ultraviolet Fluorescence	—	—	Ultraviolet Fluorescence Spectro-photometry (Pararosaniline Method)
	3 Hour	—		—	0.5 ppm ($1300\ \mu g/m^3$)	
	1 Hour	0.25 ppm ($655\ \mu g/m^3$)		75 ppbc ($196\ \mu g/m^3$)	—	
Lead	30 Day Average	$1.5\ \mu g/m^3$	Atomic Absorption	—	—	—
	Calendar Quarter	—		$1.5\ \mu g/m^3$	Same as Primary Standard	High Volume Sampler and Atomic Absorption
	Rolling 3-Month Average	—		$0.15\ \mu g/m^3$		

TABLE 5.1-5
National and California Ambient Air Quality Standards

Averaging Time	Averaging Time	California Standards		Federal Standards		
		Concentration	Method	Primary	Secondary	Method
Visibility Reducing Particles	8 Hour	Extinction Coefficient of 0.23 per kilometer—visibility of ten miles or more due to particles when relative humidity is less than 70 percent. Method: Beta Attenuation and Transmittance through Filter Tape.		No Federal Standards		
Sulfates	24 Hour	25 $\mu g/m^3$	Ion Chromatography			
Hydrogen Sulfide	1 Hour	0.03 ppm ($42\ \mu g/m^3$)	Ultraviolet Fluorescence			
Vinyl Chloride	24 Hour	0.01 ppm ($26\ \mu g/m^3$)	Gas Chromatography			

[a] To attain this standard, the 3-year average of the 98th percentile of the daily concentrations must not exceed 35 $\mu g/m^3$.

[b] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average must not exceed 100 ppb.

[c] To attain this standard, the 3-year average of the 99th percentiles of the daily maximum 1-hour average must not exceed 75 ppb.

ppm= parts per million

Source: California Air Resources Board (09/08/10)

5.1.3.4 Existing Air Quality

All ambient air quality data presented in this section were obtained from data published by CARB on the ADAM website and/or by EPA on the AIRS data website. Ambient air concentrations of ozone, NO_2, SO_2, CO, PM_{10}, and $PM_{2.5}$ are recorded at monitoring stations throughout California and Nevada. The immediate area surrounding the project site is sparsely populated valley, bordered by mountain ranges to the east and west. There is no single air quality monitoring station in the region that collects all pollutants of interest; most stations record measurements for only one or two criteria pollutants, except for those stations located in urban areas. The monitoring stations were generally positioned to represent area-wide ambient conditions rather than the localized impacts of any particular emission source or group of sources. In rural areas of the county, pollutant concentrations are not expected to vary dramatically from one location to the next, because the emission sources are few and widely distributed.

Monitoring locations were chosen based on their proximity to and representativeness of conditions at the project site. The monitoring locations listed in Table 5.1-6 were deemed representative of the project location, and were chosen to represent background pollutant concentrations for the project area. The locations of these monitoring stations relative to the project site are shown in Figure 5.1-6.

TABLE 5.1-6
Representative Background Ambient Air Quality Monitoring Stations

Pollutant	Monitoring Station	Distance to Project Site
Ozone, NO_2, PM_{10}, $PM_{2.5}$	Jean, NV (Clark County)	34 miles
CO	Barstow, CA (San Bernardino County)	97 miles
SO_2, NO_2	Trona, CA (San Bernardino County)	82 miles
Lead	San Bernardino, CA (San Bernardino County)	150 miles

Ozone. Ozone is an end-product of complex reactions between VOC and NOx in the presence of ultraviolet solar radiation. VOC and NOx emissions from vehicles and stationary sources, combined with daytime wind flow patterns, mountain barriers, temperature inversions, and intense sunlight, generally result in the highest o concentrations. For purposes of federal air quality planning, the entire GBUAPCD is classified as an attainment area with respect to national ambient standards for ozone; however, in early 2009 CARB submitted its recommendations for area designations for the revised federal 8-hour ozone standard. That recommendation included the redesignation of southern Inyo County (including the project area) to nonattainment for ozone. With respect to state standards, the entire GBUAPCD is classified as nonattainment for the 8-hour ozone standard, with the exception of Alpine County; and either unclassified (Alpine and Inyo counties) or nonattainment (Mono County) for the 1-hour state ozone standard. Table 5.1-7 shows the measured ozone levels at the Jean, Nevada, station during the period from 2001 to 2010. Note that the number of exceedances of the 1-hour and 8-hour ozone CAAQS is not included on this table, as those statistics are not tabulated for monitoring stations outside of California. However, it can be seen that the highest 8-hour averages at Jean have exceeded the California state standard of 0.07 ppm every year from 2001 through 2010, while monitored concentrations were above the state 1-hour standard of 0.09 ppm from 2001 through 2003 and again in 2007.

TABLE 5.1-7
Ozone Levels in Clark County, Nevada, Jean Monitoring Station, 2001-2010 (ppm)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Highest 1-Hour Average	0.098	0.099	0.095	0.094	0.103	0.092	0.092	0.087	0.082	0.082
Number of Days Exceeding Old Federal Standard (0.12 ppm, 1-hour)[a]	0	0	0	0	0	0	0	0	0	0
Highest 8-hour Average	0.082	0.093	0.089	0.083	0.092	0.083	0.088	0.078	0.079	0.076
Number of Days Exceeding Federal Standard (0.075 ppm, 8-hour)[b]	8	18	24	10	17	13	12	1	0	0

[a] EPA revoked the 1-hour ozone standard in all areas on June 15, 2005.

[b] To attain this standard, the 3-year average of the fourth-highest maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm. (Effective May 27, 2008).

Source: EPA AIRData website (http://www.epa.gov/air/data/index.html).

Nitrogen Dioxide. NO_2 is formed primarily from reactions in the atmosphere between NO (nitric oxide) and oxygen (O_2) or ozone. NO is formed during high-temperature combustion processes, when the nitrogen and oxygen in the combustion air combine. Although NO is much less harmful than NO_2, it can be converted to NO_2 in the atmosphere within a matter of hours, or even minutes, under certain conditions. The control of NO and NO_2 emissions is also important because of the role of both compounds in the atmospheric formation of ozone.

NO_2 concentrations were monitored at Jean until 2007. More recent NO_2 data are available from Trona, California. Table 5.1-8 shows NO_2 levels recorded at the Trona and Jean stations for the years 2001 through 2010, respectively.

Trona is located in the Searles Valley area of the Mojave Desert Air Basin, adjacent to the China Lake Naval Air Weapons Station at Ridgecrest. The Trona area is more developed than the project area, as well as being closer to the urban areas of southern California, so background concentrations of air pollutants are generally higher than concentrations in the project area. While NO_2 measured levels at Jean are more representative of levels at the project site, the concentrations measured at Trona are more current and conservatively overestimate NO_2 concentrations at the project site.

TABLE 5.1-8
Nitrogen Dioxide Levels in the Project Area, Trona and Jean (NV) Monitoring Stations, 2001-2010 (ppm)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Highest 1-Hour Average, Trona	0.055	0.051	0.052	0.055	0.053	0.050	0.055	0.062	0.049	0.052
Highest 1-Hour Average, Jean	0.038	0.043	0.041	0.032	0.039	0.036	[a]	[a]	[a]	[a]
Annual Average, Trona	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	a
Annual Average, Jean	0.004	0.004	0.004	0.004	0.004	0.004	[a]	[a]	[a]	[a]
Days Over State Standard (0.18 ppm, 1-hour)	0	0	0	0	0	0	0	0	0	0
Days Over Federal Standard (0.100 ppm, 1-hour)[b]	0	0	0	0	0	0	0	0	0	0

[a] Insufficient (or no) data were available to determine the number.

[b] The new federal 1-hour average NO_2 standard of 0.100 ppm was announced by EPA on February 9, 2010, and became effective April 12, 2010. To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average values at each monitor must not exceed 100 ppb.

Source: CARB ADAM Website (www.arb.ca.gov/adam/welcome.html).

For purposes of both state and federal air quality planning, GBUAPCD is in attainment with regard to NO_2. During the period from 2001 to 2010 (2007 for Jean), there were no violations of the CAAQS 1-hour standard (0.18 ppm) at either station. The highest 1-hour concentration recorded in the area during this 10-year period was 0.062 ppm at Trona in 2008. A new federal 1-hour NO_2 standard of 0.100 ppm became effective on April 12, 2010. To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within the GBUAPCD must not exceed 0.100 ppm; this standard has not been exceeded at either station since at least 2001. Table 5.1-8 also shows that annual average NO2 concentrations have remained well below the annual NAAQS (0.053 ppm) and annual CAAQS (0.030 ppm) at both stations during this period.

Carbon Monoxide. Carbon monoxide is a product of incomplete combustion and is emitted principally from automobiles and other mobile sources of pollution. It is also a product of combustion from stationary sources (both industrial and residential) burning fuels. Peak CO levels occur typically during winter months due to a combination of higher emission rates and stagnant weather conditions.

Table 5.1-9 shows the available data on maximum 1-hour and 8-hour average CO levels recorded at the Barstow, California, station during the period from 2001 to 2010. As indicated by this table, the maximum measured 1-hour average CO levels comply with the NAAQS and CAAQS (35.0 ppm and 20.0 ppm, respectively) and the maximum 8-hour values comply with the NAAQS and CAAQS of 9.0 ppm. The highest individual 1-hour and 8-hour CO concentrations at this station from 2001 through 2010 were 3.5 ppm and 1.5 ppm, recorded in 2006 and 2003, respectively. Because ambient CO concentrations are generally highest in the immediate vicinity of areas of high motor vehicle traffic, the concentrations at the Barstow monitoring station located in a more densely populated area compared to the project site provide a conservative overestimate of actual concentrations in the project site area. For purposes of both state and federal air quality planning, the GBUAPCD is in attainment with regard to CO.

TABLE 5.1-9
Carbon Monoxide Levels in San Bernardino County, Barstow Monitoring Station, 2001-2010 (ppm)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Highest 1-Hour Average	2.3	1.9	2.7	1.6	3.3	3.5	1.4	1.4	0.9	0.9
Highest 8-Hour Average	1.2	1.1	1.5	1.2	1.3	1.2	0.7	1.2	0.9	*
Days Over State Standard (9 ppm, 8-hour)	0	0	0	0	0	0	0	0	0	0
Days Over Federal Standard (9 ppm, 8-hour)	0	0	0	0	0	0	0	0	0	0

*Insufficient (or no) data were available to determine the number.

Note: Data completeness for CO concentrations at the Barstow station averaged 95 percent over the ten-year analysis period.

Sources: CARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AIRS Website (www.epa.gov/air/data/index.html)

Sulfur Dioxide. SO_2 is produced by the combustion of any sulfur-containing fuel. It is also emitted by chemical plants that treat or refine sulfur or sulfur-containing chemicals. Natural gas contains nearly negligible sulfur, whereas fuel oils may contain much larger amounts. Because of the complexity of the chemical reactions that convert SO_2 to other compounds (such as sulfates), peak concentrations of SO_2 occur at different times of the year in different parts of California, depending on local fuel characteristics, weather, and topography. The GBUAPCD is considered to be in attainment for SO_2 for purposes of state and federal air quality planning.

Table 5.1-10 shows the available data on maximum 1-hour, 3-hour, 24-hour, and annual average SO_2 levels recorded at the Trona, California, station during the period from 2001 to 2010. As indicated by this table, the maximum measured 1-hour average SO_2 levels comply with the new NAAQS (0.075 ppm) and CAAQS (0.25 ppm), the maximum 3-hour average SO_2 levels comply with the NAAQS (0.5 ppm), and the maximum 24-hour values comply with the CAAQS of 0.04 ppm. The federal 24-hour and annual standards for SO_2 have been superseded by the new 1-hour standard, which became effective on August 23, 2010.

TABLE 5.1-10
Sulfur Dioxide Levels in San Bernardino County, Trona Monitoring Station, 2001-2010 (ppm)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Highest 1-Hour Average	0.012	0.012	0.008	0.019	0.018	0.033	0.014	0.036	0.011	[a]
Highest 3-Hour Average	0.010	0.009	0.005	0.010	0.011	0.017	0.009	0.006	0.008	[a]
Highest 24-Hour Average	0.007	0.007	0.003	0.016	0.005	0.006	0.005	0.005	0.003	[a]
Annual Average	0.001	0.001	0.000	0.003	0.003	0.003	0.000	0.000	0.000	[a]
Days Over State Standard (0.25 ppm, 1-hour)	0	0	0	0	0	0	0	0	0	0
Days Over Federal Standard (75 ppb, 1-hour)[b]	0	0	0	0	0	0	0	0	0	0

[a] Insufficient (or no) data were available to determine the number.

[b] Final rule signed June 22, 2010, effective August 23, 2010. To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb.

Sources: CARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AIRS Website (www.epa.gov/air/data/index.html)

Respirable Particulate Matter (PM_{10}). Particulates in the air are caused by a combination of wind-blown fugitive dust; particles emitted from combustion sources and manufacturing processes; and organic, sulfate, and nitrate aerosols formed in the air from emitted hydrocarbons, sulfur oxides, and nitrogen oxides. Particulates with a diameter less than or equal to 10 microns are referred to as PM_{10}, and are regulated because they can be inhaled, leading to health effects. Fine particulates, referred to as $PM_{2.5}$ and having a diameter equal to or less than 2.5 microns, are a subset of PM_{10} that is also regulated. $PM_{2.5}$ standards are discussed later in this section.

PM_{10} is the most serious air quality issue in the GBUAPCD region, and the entire district is classified as nonattainment for the state PM_{10} standards. For purposes of federal air quality planning, the entire district is designated as "unclassified" with the exception of the Coso Junction area, which is designated attainment, and the three areas listed below, which are designated as nonattainment for the federal PM_{10} standards.

- Owens Lake is one of the largest single sources of PM_{10} in the United States. GBUAPCD has collaborated with the City of Los Angeles and the Los Angeles Department of Water and Power to implement dust control measures that have significantly reduced total PM_{10} emissions from the dry lakebed. Owens Lake is over 100 km west of the project site, separated by significant terrain and Death Valley National Park.

- Mono Lake also violates the federal PM_{10} standard, and the State Water Resources Control Board (SWRCB) has set requirements for raising the level of Mono Lake level as a mitigation measure. The lake has risen about 10 feet since the mid-90s and PM_{10} levels at some sites have decreased. Current estimates are that the lake level needs to rise an additional 9 feet in order to sufficiently control PM_{10} emissions. Mono Lake is several hundred miles northwest of the project site.
- The Mammoth Lakes area has high levels of PM_{10} in the winter months due to a combination of wood smoke and cinders used on icy roads for better traction during the winter. Mammoth Lakes is also several hundred miles northwest of the project site.

Although the PM_{10} monitoring site at Pahrump, Nevada, is closer to the project site than the Jean station, the Pahrump data are strongly affected by local windblown dust, and therefore are not representative of regional background concentrations. As noted by the Nevada Bureau of Air Quality Planning (NVBAQP, 2010):

> *Fast population growth in the '90s through mid-2006 created intensive development. Large parcels of land were cleared of vegetation, subdivided and prepared for housing construction. Dirt and gravel roads were constructed. Many of the planned housing developments never materialized and the lots are now disturbed, vacant areas.*
>
> *As a result of the disturbed, vacant land and the number of dirt and gravel roads, fugitive dust (particulate matter less than 10 microns, or PM) became a problem. The Pahrump valley is subject to high winds and these winds often create dust storms.*

However, the project site is not downwind of the Pahrump area under most meteorological conditions[2] and therefore would not be expected to be affected by the dust storms that create high localized PM_{10} concentrations in Pahrump. Consequently, PM_{10} concentrations monitored at Jean better represent conditions in the project area.

Table 5.1-11 shows the maximum PM_{10} levels recorded at the Jean, Nevada, monitoring station during the period from 2001 through 2010 and the arithmetic annual average concentrations for the same period. (The arithmetic annual average is simply the arithmetic mean of the daily observations.) This table shows that maximum 24-hour PM_{10} levels recorded at Jean exceeded the CAAQS state standard of 50 $\mu g/m^3$ from 2001 through 2009. The maximum daily concentration recorded at Jean during the analysis period was 208 $\mu g/m^3$ in 2002, although that is the only year in which 24-hour average concentrations exceeded the applicable federal standard. The maximum annual arithmetic mean concentration, recorded in 2005, was 17.0 $\mu g/m^3$, well below the federal annual standard of 50 $\mu g/m^3$. The federal annual PM_{10} standard was revoked by the EPA in 2006 due to a lack of evidence linking health problems to long-term exposure to coarse particle pollution. The project area is considered a federal attainment area for PM_{10}.

[2] See wind roses in Appendix 5.1A.

TABLE 5.1-11
PM_{10} Levels in Clark County, Nevada, Jean Monitoring Station, 2001-2010 (μg/m³)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Highest 24-Hour Average	75.0	208.0	124.0	71.0	66.0	62.0	60.0	96.0	81.3	49
Annual Arithmetic Mean	13.0	16.0	15.0	16.0	17.0	12.0	13.0	14.0	12.4	8.5
Days Over Federal Standard (150 μg/m³)*	0	1.1	0	0	0	0	0	0	0	0

*On December 17, 2006, the annual PM_{10} federal standard (50 μg/m³) was revoked.
Source: EPA AIRS Website (www.epa.gov/air/data/index.html)

Fine Particulates ($PM_{2.5}$). Fine particulates result from fuel combustion in motor vehicles and industrial processes, residential and agricultural burning, and atmospheric reactions involving NOx, SOx, and organics. Fine particulates are referred to as $PM_{2.5}$ and have a diameter equal to or less than 2.5 microns. In 1997, EPA established annual and 24-hour NAAQS for $PM_{2.5}$ for the first time. The most recent revision to the standard regulating the 3-year average of the 98th percentile of 24-hour $PM_{2.5}$ concentrations (35 µg/m³) became effective on December 17, 2006.

The $PM_{2.5}$ data in Table 5.1-12 show that the national 24-hour average NAAQS of 35 µg/m³ has not been exceeded in the project area during the ten-year analysis period. The maximum recorded 24-hour average value was 20.5 µg/m³ in 2001. The maximum annual arithmetic mean of 4.9 µg/m³, recorded in 2008, is below both the national standard of 15 µg/m³ and the California standard of 12 µg/m³. The GBUAPCD is in attainment with the state $PM_{2.5}$ standard, and is classified as “unclassifiable/attainment” for the federal $PM_{2.5}$ standards.

TABLE 5.1-12
$PM_{2.5}$ Levels in Clark County, Nevada, Jean Monitoring Station, 2001-2010 (μg/m³)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Highest 24-Hour Average (federal only)*	20.5	14.1	13.2	8.2	11.3	11.4	13.7	13.8	13.0	13.5
Annual Arithmetic Mean	4.2	4.0	3.7	3.4	3.8	3.5	4.0	4.9	4.0	3.5
Days Over Federal Standard (35 μg/m³)*	0	0	0	0	0	0	0	0	0	0

*EPA lowered the 24-hour standard from 65 μg/m3 to 35 μg/m3 on December 17, 2006. Compliance with this standard is based on the 3-year average of the 98th percentile daily concentrations.

Source: EPA AIRS Website (www.epa.gov/air/data/index.html)

Airborne Lead. Lead pollution has historically been emitted predominantly from the combustion of fuels. However, legislation in the early 1970s required a gradual reduction of the lead content of gasoline. Beginning with the introduction of unleaded gasoline in 1975, lead levels have been dramatically reduced throughout the U.S., and violations of the ambient standards for this pollutant have been virtually eliminated.

On October 15, 2008, EPA revised the federal ambient air quality standard for lead, lowering it from 1.5 µg/m³ to 0.15 µg/m³ for both the primary and the secondary standard. EPA determined that numerous health studies are now available that demonstrate health effects at much lower levels of lead than previously thought. EPA subsequently published the final rule in the Federal Register on November 12, 2008.

In addition to revising the level of the standard, EPA changed the averaging time from a quarterly average to a rolling three-month average. The level of the standard is "not to be exceeded" and is evaluated over a three-year period. Lead levels are measured as lead in total suspended particulate (TSP). The revised lead standard also includes new monitoring requirements.

Ambient lead levels are monitored in San Bernardino. Table 5.1-13 lists the federal air quality standard for airborne lead and the levels reported in San Bernardino between 2001 and 2010. Maximum quarterly levels are not reported on EPA's website. Because the maximum 24-hour averages must be higher than the quarterly average, the data show that lead levels are actually below the federal standard.[3]

TABLE 5.1-13
Airborne Lead Levels in San Bernardino County, San Bernardino Monitoring Station, 1997-2006 ($\mu g/m^3$)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Highest 24-hour Average	0.07	0.04	0.35	0.03	0.03	0.03	0.07	0.02	0.02	*
Days Over Federal Standard (1.5 $\mu g/m^3$, quarterly)	0	0	0	0	0	0	0	0	0	*

*Insufficient (or no) data were available to determine the number.
Source: EPA AirData website (http://www.epa.gov/air/data/index.html).

Particulate Sulfates. Sulfate compounds found in the lower atmosphere consist of both primary and secondary particles. Primary sulfate particles are directly emitted from open pit mines, dry lakebeds, and desert soils. Combustion of sulfur-containing fuels is another source of sulfates, both primary and secondary. Secondary sulfate particles are produced when oxides of sulfur (SOx) emissions are transformed into particles through physical and chemical processes in the atmosphere. Particles can be transported long distances.

The GBUAPCD is classified as an attainment area with respect to the state ambient standard for sulfates; there is no federal standard.

Other State-Designated Criteria Pollutants. Along with sulfates, California has designated hydrogen sulfide and visibility-reducing particles as criteria pollutants, in addition to the federal criteria pollutants. According to the GBUAPCD, the Coso geothermal development east of Coso Junction on the China Lakes Naval Weapons Center property has the potential to violate the state standard for hydrogen sulfide, but has not yet done so because the standard does not apply on the Naval Weapons Center property. The GBUAPCD has worked with the operators of that facility to minimize the emissions, and to date there have been no violations of the standards off the base. Currently, the Mono County and Inyo County portions of the GBUAPCD are classified as attainment for hydrogen sulfide, while the remainder of the district is "unclassified" for this pollutant. The entire GBUAPCD is classified as attainment for visibility-reducing particles.

[3] ARB no longer reports summary lead statistics on its website.

Attainment status for the project area is summarized in Table 5.1-14.

TABLE 5.1-14
2010 Attainment Status in Inyo County (Project Area)

	Attainment Status	
Pollutant	**Federal Standards**	**California Standards**
Ozone – 1-hour	Revoked 6/16/05	Unclassified
Ozone – 8-hour	Unclassified/Attainment*	Nonattainment
CO – 8-hour	Unclassified/Attainment	Attainment
NO_2	Unclassified/Attainment	Attainment
SO_2	Unclassified	Attainment
PM_{10}	Unclassified	Nonattainment
$PM_{2.5}$	Unclassified/Attainment	Attainment

*As discussed above, CARB proposed the redesignation of southern Inyo County to nonattainment for the federal 8-hour average ozone standard in early 2009; EPA has not yet acted on this redesignation request.

Source: CARB, Air Quality Data Branch, December 2009; available at http://www.arb.ca.gov/desig/adm/adm.htm (accessed May 2011)

5.1.4 Environmental Analysis

Ambient air quality impact analyses for the project have been conducted to satisfy the GBUAPCD and CEC requirements for analysis of impacts from criteria pollutants (NO_2, CO, PM_{10}, $PM_{2.5}$ and SO_2) and noncriteria pollutants during project construction and operation.[4] The analyses cover each phase of the project. Section 5.1.4.1 gives an overview of the analytical approach and the emitting units at the facility. Section 5.1.4.2 discusses facility operations. Section 5.1.4.3 presents the emissions for project operation and construction of the project. Section 5.1.4.4 discusses emissions and fuel use monitoring, and Section 5.1.4.5 presents the ambient air quality impacts of project construction and operation.

5.1.4.1 Overview of the Analytical Approach to Estimating Facility Impacts

The following sections describe the emission sources that have been evaluated, the results of the ambient impact analyses, and the evaluation of project compliance with the applicable air quality regulations, including the GBUAPCD's NSR requirements. These analyses are designed to confirm that the project's design features lead to less-than–significant impacts even with the following conservative analysis assumptions and procedures: maximum allowable emission rates, project operating schedules that lead to maximum emissions, worst-case meteorological conditions, and adding the worst-observed existing air quality to the highest potential ground-level impact from modeling, even when all of these situations could not physically occur at the same time.

[4] As discussed in Section 5.1-1, transmission and gas line construction will take place in Nevada.

5.1.4.1.1 Emitting Units

The project comprises two 250 MW (net) plants—Solar Plant 1 to the north and Plant 2 to the south—and a common area. The relative locations of the three areas are shown in Figure 2.1-2 (Section 2.0, Project Description).

Each plant will have eight emitting units, consisting of five natural-gas-fired boilers, two diesel fuel-fired emergency engines, and a wet surface air cooler. The common area will contain diesel fuel-fired emergency equipment consisting of a small emergency generator and a fire pump.

Three types of boilers will be used at each power block. Each boiler will be equipped with low-NOx burners and flue gas recirculation (FGR) for NOx control; CO will be controlled using good combustion practices; and particulate and VOC emissions will be minimized through the use of natural gas as the fuel. Specifications for the new boilers are summarized in Table 5.1-15.

To augment the solar output when solar energy diminishes or during transient cloudy conditions, each plant may utilize three 500 MMBtu/hr natural-gas-fired auxiliary boilers that may be operated up to several hours on summer weekdays. The auxiliary boilers may also be used to extend daily power generation. However, on an annual basis heat input from natural gas will be limited by fuel use and other conditions to less than 10 percent of the heat input from the sun.

Each plant will use one 249 MMBtu/hr natural-gas-fired startup boiler to preheat the solar boiler and steam turbine generator piping before solar energy is available. This will enhance project efficiency by allowing solar flux to maximize output more quickly than if solar heating alone were used to preheat the entire system. During cloudy days or in case of emergency shutdown, the startup boilers may be used to keep the system hot to facilitate plant restart.

Additionally, one small (12 MMBtu/hr) natural-gas-fired boiler, called a nighttime preservation boiler, will be used at each plant to provide superheated steam to keep the steam turbine generators and boiler pump gland systems under vacuum overnight and during other shutdown periods when steam is not available. Using these small boilers will be more efficient than allowing these systems to cool and then using the larger startup boilers to reestablish the vacuums in the morning. Because of their low heat input, the nighttime preservation boilers are exempt from GBUAPCD permitting requirements (District Rule 201.F, exempting "Steam generators…that have a maximum heat input rate of less than 15 million British Thermal Units (BTU) per hour (gross), and are fired exclusively with natural gas…").

TABLE 5.1-15
Natural Gas Boiler Specifications

		Auxiliary Boilers	Startup Boilers	Nighttime Preservation Boilers
Make & Model		Rentech or equivalent	Rentech D-type water tube or equivalent	Cleaver Brooks or equivalent
Fuel		Natural gas	Natural gas	Natural gas
Maximum Boiler Heat Input Rate		500 MMBtu/hr @ HHV	249 MMBtu/hr @ HHV	12 MMBtu/hr @ HHV
Steam Production Rate		350,000 lb/hr	200,000 lb/hr	8,000 lb/hr
Stack Exhaust Temperature		360°F	360°F	325°F
Exhaust Flow Rate		~155,300 acfm	~84,000 acfm	~3,700 acfm
Exhaust O_2 Concentration, dry volume		3.0%	3.0%	3.0%
Exhaust CO_2 Concentration, dry volume		10.2%	10.2%	10.2%
Exhaust Moisture Content, wet volume		16.3%	16.3%	16.3%
Emission Controls:	NOx	Low-NOx Burners/FGR (9.0 ppmvd NOx @ 3% O_2)	Low-NOx Burners/FGR (9.0 ppmvd NOx @ 3% O_2)	Low-NOx Burners/FGR (9.0 ppmvd NOx @ 3% O_2)
	CO	Combustion controls (50 ppmvd @ 3% O_2)	Combustion controls (25 ppmvd @ 3% O_2)	Combustion controls (50 ppmvd @ 3% O_2)
	VOC	Combustion controls (12.6 ppmvd @ 3% O_2)	Combustion controls (12.6 ppmvd @ 3% O_2)	Combustion controls (10 ppmvd @ 3% O_2)

Table 5.1-16 presents the nominal fuel properties for the CPUC-regulated natural gas to be used by the boilers.

TABLE 5.1-16
Nominal Fuel Properties—Natural Gas

Component Analysis		Chemical Analysis	
Component	Average Concentration, Volume	Constituent	Percent by Weight
CH_4	96.1%	C	71 %
C_2H_6	1.8%	H	24 %
C_3H_8	0.3%	N	3 %
Iso-C_4H_{10}	0.05%	O	2 %
n-C_4H_{10}	0.05%	S	0.75 gr/100 scf
iso-C_5H_{12}	0.01%	Higher Heating Value	1,020 Btu/scf
n-C_5H_{12}	0.01%		22,840 Btu/lb

TABLE 5.1-16
Nominal Fuel Properties—Natural Gas

Component Analysis		Chemical Analysis	
Component	**Average Concentration, Volume**	**Constituent**	**Percent by Weight**
C_6+	0.03%		
N_2	0.04%		
CO_2	1.24%		
S	<0.0001%		
Total	100%		

Each plant will also have one 2,500 kW diesel emergency generator at each power block to provide backup power to the facility in case of loss of line power; there will be one smaller 250 kW diesel emergency generator to provide emergency power to the common area (for a total of three emergency generators). Specifications for these emergency generators are provided in Table 5.1-17.

TABLE 5.1-17
Emergency Generator Specifications

	Power Blocks (2 total)	Common Area
Make & Model	Caterpillar C175-16 SCAC or equivalent	Caterpillar C9 ATAAC or equivalent
CARB Cert	U-R-001-0387 (Tier 2)	U-R-001-0373 (Tier 3)
Fuel	CARB diesel	CARB diesel
Generator Rating, kW	2,500	250
Engine Rating, bhp	3,354	335
Fuel Consumption, gallons/hr	175	19.4
Stack Exhaust Temperature	831.4°F	853.9°F
Exhaust Flow Rate	20,461 acfm	2,242 acfm

One diesel fire pump engine will be located in each power block as well as in the common area (total of three fire pump engines) to comply with fire codes. Typical specifications for these units are provided in Table 5.1-18.

TABLE 5.1-18
Specifications for the Diesel Fire Pump Engines

	Power Block Fire Pump Engines	Common Area Fire Pump Engine
Make & Model	Cummins CFP9E-F40 or equivalent	Cummins CFP9E-F20 or equivalent
CARB Cert	U-R-002-0521	U-R-002-0521
Fuel	CARB diesel	CARB Diesel
Engine Rating, bhp	271	233
Pump Speed, RPM	1470	1470
Fuel Consumption, gallons/hr	14.0	12.0
Stack Exhaust Temperature	1083°F	1033°F
Exhaust Flow Rate	1,584 acfm	1,527 acfm

Diesel Fuel Supply and Storage

Diesel fuel for the emergency generators and fire pump engines will be stored in individual day tanks located adjacent to the units. The fire pump engine day tanks will be located in the individual fire pump houses. The diesel generator day tanks will be located in the generator skid bases. Diesel fuel consumption rates and diesel tank capacities are shown in Table 5.1-19.

TABLE 5.1-19
Maximum Diesel Fuel Use and Tank Capacities

Engine	Maximum Fuel Consumption Rate, gal/hr	Target Fuel Supply, hours	Fuel Day Tank Capacity, gal
Emergency Diesel Generators, Power Blocks	175	8	1600
Emergency Diesel Generator, Common Area	19.4	8	180
Diesel Fire Pumps, Power Blocks	14	25	350
Diesel Fire Pump, Common Area	12	25	300

Diesel fuel for the mirror cleaning vehicles will be stored in an 8,000-gallon, double-walled, aboveground concrete storage tank. Nominal dimensions will be 23 feet long, 8 feet wide and 9 feet high.

The tanks are exempt from GBUAPCD permitting requirements per Rule 201.H.4 (exempting “Unheated storage of organic materials with an initial boiling point of 300 F or greater”).

Wet Surface Air Coolers

The main process steam cooling system will use dry cooling. The Applicant proposes to use one partial dry-cooling system (PDCS) in each power block for the auxiliary systems, including, but not limited to, generator and lube oil cooling for major equipment. PDCS was selected because dry cooling cannot provide adequate cooling for these systems when ambient temperatures exceed approximately 85°F. The PDCS is a closed-loop two-stage cooling system. In this system, the heat will be rejected using ambient air in a dry cooling system, followed by a closed-loop evaporative fluid cooler for additional cooling at higher ambient temperatures. Under most conditions, all cooling will be provided by the dry portion of the cooling system. The wet portion is operated only when the ambient temperature is 86°F or higher.

The dry cooling portion of the PDCS has no air emissions. The wet portion of the PDCS will be a small wet surface air cooler (WSAC). A WSAC uses mechanical, induced-draft technology in a closed circuit. In the fluid cooler, the process fluid to be cooled is pumped through coils and cooling water passes over the coils, cooling the process fluid by evaporation. In this system, the cooling water does not contact the process fluid. Particulate emissions result from evaporation of the cooling water that drifts from the fluid cooler. Deionized water will be used for makeup water. As a result, the total dissolved solids (TDS) level of the recirculating water will still be very low (400 ppmw) even after 20 cycles of concentration. High efficiency drift eliminators will help to minimize emissions from the WSACs. The WSACs are exempt from GBUAPCD permit requirements per District Rule 201.D.4 (exempting "[w]ater cooling towers…not used for evaporative cooling of process water…").

Oil/Water Separators and Evaporators

As discussed in Section 2.0, Project Description, HHSEGS will include small oil/water separators and evaporators at each power block. General plant drains will collect containment area washdown, sample drains, and drainage from facility equipment drains. Water from these areas will be collected in a system of floor drains, hub drains, sumps, and piping and routed to the collection system. Drains that potentially could contain oil or grease will first be routed through the oil/water separators. Water passing through the oil/water separator will be reduced in volume by small thermal evaporators that will operate intermittently, using either solar energy or steam as a source of heat.

The capacity of each oil/water separator will be 50 gallons per minute; however, the expected throughput, based on the water balance, is only 2 gallons per minute at each power block. The oil-water separators are exempt from permitting per District Rule 201.H.4 (exempting "containers, reservoirs or tanks used exclusively for: … unheated storage of organic materials with an initial boiling point of 300 F or greater.")

5.1.4.2 Facility Operations

The auxiliary boilers will be operated mainly on weekdays during the peak summer months (June through September) to augment the solar operation when solar energy diminishes or during transient cloudy conditions when solar insolation alone is not sufficient to generate adequate steam for the steam turbines. The auxiliary boilers will be started each summer weekday at about 2:30 p.m. and heated up using intermittent gas burner firing. At about 3:00 p.m. the boilers will start to generate steam and the load will be increased at a rate dictated by the boiler manufacturer. The auxiliary boilers are expected to reach full capacity by 6:00 p.m. and will continue to operate at full load for several hours. In this operating mode, all three boilers at a plant would be started, loaded, and operated in the same manner. On cloudy days, the auxiliary boilers may operate independently, depending on steam requirements, and may operate more hours at different loads. One auxiliary boiler at each power block would be maintained on hot standby mode (with very low heat input to maintain full pressure and minimum steam flow), while the other boilers would be on warm standby (in which a boiler is periodically started and held at low fire until it returns to the warm standby temperature). NOx emissions from the auxiliary boilers will be continuously monitored to ensure that daily NOx emissions remain below 230 pounds per day. The auxiliary boilers are not expected to operate between October and May. Maximum annual auxiliary boiler use will be the equivalent of 400 full-load hours per year per boiler. Heat input from natural gas will be limited to below 10 percent of the heat input from the sun, on an annual basis.

The startup boilers will be operated up to two hours per day in the morning to warm the main steam systems before solar energy is available to the solar boilers. During cloudy days or in case of emergency shutdown of the solar boilers, the startup boilers may be used to keep the system hot to facilitate plant restart. Daily maximum impacts from boiler operations were calculated assuming that each boiler would be fired up to 2 hours at full load on any given day.

The nighttime preservation boilers will operate during the nighttime hours (8 to 10 hours per day during the summer months, up to 12 hours per day during the winter months) to maintain system temperatures overnight.

Maximum annual startup boiler use will be the equivalent of 800 full-load hours per year per boiler; maximum annual nighttime boiler operation will be the equivalent of 4,000 full-load hours per year per boiler. The annual operating schedule is summarized in Table 5.1B-8, Appendix 5.1B.

Boiler heat inputs, as summarized in Table 5.1-15, correspond to the proposed individual unit emission limits. The natural gas fuel use limits that are proposed as permit conditions correspond to the operating schedule described above and are shown in bold in Table 5.1-20: hourly heat input to each unit, total combined daily heat input to all units at both plants, and total combined annual heat input to both plants.

Emission rates and operating parameters for the boilers are shown in Appendix 5.1B, Tables 5.1B-1, B-2 and B-3. Emission rates and operating parameters for the emergency engines are shown in Appendix 5.1B, Tables 5.1B-4 and B-5. Emission rates and operating parameters for the fire pump engines are shown in Appendix 5.1B, Tables 5.1B-6 and B-7. Daily and annual fuel use calculations are shown in Appendix 5.1B, Table 5.1B-9.

TABLE 5.1-20
Maximum Facility Natural Gas Fuel Use, Boilers (MMBtu)

Period	Auxiliary Boilers	Startup Boilers	Nighttime Preservation Boilers	Total Fuel Use (all boilers)
Per Hour (each unit)	**500**	**249**	**12.25**	3,522.5
Per Day (total, all units)	21,000	996	294	**22,290**
Per Year (total, all units)	1,200,000	398,400	97,976	**1,696,376**

Bold text indicates the natural gas fuel use limits that are proposed as permit conditions.

Emergency engines will be tested to ensure that they will function when needed. In order to provide maximum flexibility, it was assumed that each engine would use the 50 hours of testing allowed under the state stationary engine Airborne Toxics Control Measure (ATCM) plus an additional 150 hours per year of emergency operation.[5] It was also assumed that as a worst case, all engines would be tested at any given time. The engines would not be tested on days when the auxiliary boilers are operating. Combined annual fuel use in all engines, shown in bold in Table 5.1-21, will be limited by permit condition.

TABLE 5.1-21
Maximum Facility Diesel Fuel Use, Engines (MMBtu)

Period	Power Block Emergency Engines	Common Area Emergency Engine	Power Block Fire Pump Engines	Common Area Fire Pump Engine	Total Fuel Use (all engines)
Per Hour (each unit)*	11.9	1.3	1.0	0.8	27.7
Per Day (total, all units)	23.8	1.3	1.9	0.8	27.7
Per Year (total, all units)	9,520	528	653	381	**11,081**

*Based on 30-minute test operations.

As discussed above, the main process steam will be cooled using a dry cooling system. A PDCS will be used in each power block for auxiliary system cooling, including but not limited to lube and seal oil cooling for major equipment, and chemical feed system cooling requirements. Only the WSAC portion of the cooling system will have air emissions, and that portion of the cooling system is expected to operate only under high ambient temperature conditions.

5.1.4.3 Emissions Calculations

This section presents calculations of emissions increases from the proposed new boilers and engines. Tables containing the detailed calculations are included in Appendix 5.1B.

[5] For criteria pollutant emissions calculations, operations under emergency conditions are not included because those hours are not limited by the ATCM. However, for the calculation of greenhouse gas emissions, emergency operations must be included and emissions must be calculated based on total potential to emit. See Section 5.1.4.3.5, Greenhouse Gas Emissions.

5.1.4.3.1 Criteria Pollutant Emissions: Combustion Equipment

The boilers, emergency engines, and diesel fire pump engine emission rates have been calculated from vendor data, project design criteria, and established emission calculation procedures. The emission rates for the boilers are shown in the following tables. The emission rates for the diesel emergency and fire pump engines are shown in Tables 5.1B-4 through 5.1B-7 of Appendix 5.1B.

Boiler Emissions during Normal Operations. Emissions of NOx, CO, and VOC were calculated from emission limits (in ppmv @ 3% O_2) and the exhaust flow rates. The NOx emission limit reflects the use of low-NOx burners and flue gas recirculation. SOx emissions were calculated from the heat input (in MMBtu) and a SOx emission factor (in lb/MMBtu). The SOx emission factor of 0.0021 lb/MMBtu was derived from the maximum allowable (i.e., CPUC-approved tariff limit) fuel sulfur content of 0.75 grains per 100 standard cubic feet (gr/100 scf). Maximum emissions are based on the highest heat input rates shown in Table 5.1-15.

The VOC and CO emission limits reflect the use of good combustion practices. SOx, PM_{10}, and $PM_{2.5}$ emission rates are based on the use of natural gas as the fuel and good combustion practices.

Maximum hourly PM_{10} emissions are based on design specifications. $PM_{2.5}$ emissions were determined based on the assumption that all boiler exhaust particulate is less than 2.5 microns in diameter.

Emissions for the boilers are summarized in Table 5.1-22. The auxiliary and startup boilers are expected to have a 4:1 turndown ratio; the nighttime preservation boilers are expected to have a 5:1 turndown ratio. Full-load emission rates will be achieved throughout the turndown range. Emissions during other activities are discussed in more detail below.

TABLE 5.1-22
Maximum Hourly Emission Rates: Boilers, Normal Operations

Pollutant	ppmvd @ 3% O_2	lb/MMBtu	lb/hr
Auxiliary Boilers (each)			
NOx	9.0	0.011	5.4
SO_2*	1.7	0.002	1.1
CO	50	0.037	18.3
VOC	12.6	0.0053	2.6
$PM_{10}/PM_{2.5}$	n/a	0.005	2.5
Startup Boilers (each)			
NOx	9.0	0.011	2.7
SO_2*	1.7	0.002	0.5
CO	25	0.018	4.6
VOC	12.6	0.0053	1.3
$PM_{10}/PM_{2.5}$	n/a	0.005	1.25

TABLE 5.1-22
Maximum Hourly Emission Rates: Boilers, Normal Operations

Pollutant	ppmvd @ 3% O_2	lb/MMBtu	lb/hr
Nighttime Preservation Boilers (each)			
NOx	9.0	0.011	0.13
SO_2*	1.7	0.002	0.03
CO	50	0.037	0.45
VOC	10	0.004	0.05
$PM_{10}/PM_{2.5}$	n/a	0.005	0.06

*Based on maximum natural gas sulfur content of 0.75 grains/100 scf.

Auxiliary Boiler Emissions During Hot/Warm Standby. During cloudy conditions, when solar energy is not sufficient to keep the steam turbine online, the auxiliary boilers will be kept in warm or hot standby mode to allow them to ramp up to operating pressure within about 30 minutes. In hot stand-by, a boiler is maintained at full pressure with minimum steam flow by firing at up to about 5 percent of rated heat input. In warm standby, a boiler is periodically started and held at low fire until it returns to a preset warm standby temperature. Because of the extremely low heat input experienced during these modes, combustion is less efficient and NOx, VOC, CO, and PM_{10} emission concentrations are elevated. However, hourly mass emission rates during these standby modes will be lower than full load emission rates because of the extremely low heat input rate. Hourly emission rates for the auxiliary boilers during hot standby are summarized in Table 5.1-23. Hourly emission rates for the boilers during warm standby operations will be even lower because firing will be intermittent.

TABLE 5.1-23
Maximum Hourly Emission Rates: AuxiliaryBoilers, Hot/Warm Standby Operations

Pollutant	ppmvd @ 3% O_2	lb/MMBtu	lb/hr
Auxiliary Boilers (each)			
NOx	100	0.12	3.0
SO_2*	1.7	0.002	0.05
CO	250	0.18	4.6
VOC	25	0.0105	0.3
$PM_{10}/PM_{2.5}$	n/a	0.01	0.25

*Based on maximum natural gas sulfur content of 0.75 grains/100 scf.

Boiler Emissions During Startup/Shutdown. The auxiliary boilers may require up to 6 hours to achieve permitted emission limits (at 25 percent load) after an extended period of shutdown (cold start). The startup boilers may require up to 5 hours to achieve permitted limits, while the nighttime preservation boilers are expected to require less than 4 hours. Emissions during cold startup of each boiler were calculated assuming an average heat input rate over the startup period equivalent to half the minimum load (12.5 percent of maximum hourly heat input for the auxiliary and startup boilers and 10 percent of maximum hourly heat input for the nighttime preservation boilers). Expected emissions during a cold startup of the auxiliary and startup boilers are shown in Table 5.1-24; startup emissions for the nighttime preservation boilers are shown in Table 5.1-25. Emissions were calculated assuming that only one auxiliary or nighttime preservation boiler at each plant will be in cold startup at a time, and a boiler would require the full number of hours for startup and have the emissions shown only when other boilers are not operating and available to provide preheat steam. The startup boilers may undergo a cold startup when the nighttime preservation boilers are in operation.

A cold startup of an auxiliary boiler is expected to occur about once every 2 weeks during the summer season. Based on 4 months of expected summertime operation, a cold startup of an auxiliary boiler would occur about 8 times per year. Because the startup and nighttime preservation boilers will operate year-round, cold startups of these boilers would be expected to occur about every 4 weeks, or approximately 13 times per year.

TABLE 5.1-24
Maximum Hourly Emission Rates: Auxiliary and Startup Boilers, Startup Operations

Pollutant	ppmvd @ 3% O_2	lb/MMBtu	Auxiliary Boiler lb/hr	Startup Boiler lb/hr
NOx	75	0.09	5.6	2.8
SO_2[a]	1.7	0.002	0.13	0.07
CO	300	0.22	13.7	6.8
VOC	60	0.025	1.6	0.8
$PM_{10}/PM_{2.5}$	n/a	0.01	0.63	0.31

*Based on maximum natural gas sulfur content of 0.75 grains/100 scf.

TABLE 5.1-25
Maximum Hourly Emission Rates: Nighttime Preservation Boilers, Startup Operations

Pollutant	ppmvd @ 3% O_2	lb/MMBtu	lb/hr
NOx	70	0.084	0.13
SO_2*	1.7	0.002	0.003
CO	275	0.20	0.31
VOC	55	0.023	0.04
$PM_{10}/PM_{2.5}$	n/a	0.01	0.02

*Based on maximum natural gas sulfur content of 0.75 grains/100 scf.

Hourly NOx emissions during cold startup of the auxiliary and startup boilers are expected to be slightly higher than hourly emissions during normal operation. Hourly CO emissions from the startup boiler may also be higher during cold startup than during normal operation.

During routine daily startups, emissions concentrations may be higher than those shown for normal operations in Table 5.1-22 until each boiler reaches its minimum compliant load

(25 percent of rated load for the auxiliary and startup boilers; 20 percent of rated load for the nighttime preservation boilers). However, because of the shorter startup times and low heat input rates, the boilers are expected to comply with the pound per hour emission rates on a 3-hour average basis during these routine daily startups.

Boiler Operations During Commissioning Activities. During plant commissioning, emissions will be elevated during the first several days of operation of each boiler as it is started up and held at low loads for tuning. Expected emissions during boiler commissioning activities are shown in Table 5.1B-18, Appendix 5.1B. Only one boiler at a time will be undergoing commissioning activities.

5.1.4.3.2 Criteria Pollutant Emissions: Wet Surface Air Coolers

The dry cooling portion of the PDCS has no air emissions. The wet portion of each cooling system emits only water vapor and will be equipped with a 3,276-gpm WSAC. Particulate emissions result from evaporation of the cooling water that drifts from the fluid cooler.

Deionized water will be used for makeup water. As a result, the TDS level of the recirculating water will still be very low (400 ppmw) even after 20 cycles of concentration.

Details of the cooling water drift calculation for the WSACs are shown in Appendix 5.1B, Table 5.1B-10. Particulate emissions from each cooling system will be about 6 pounds per year.

5.1.4.3.3 Criteria Pollutant Emissions: Mirror Cleaning

Mirror washing will employ a high-pressure system using demineralized water, by means of vehicle-towed trailers that contain a water tank, positive displacement water pumps that deliver water at high-pressure, and spray nozzles operated by the cleaning crew. The washing is expected to be done on a 2-week rotating cycle. The water washing will be supplemented with brushing, which will be done on an 8-week schedule.

Each solar field is divided into three zones for the purpose of heliostat cleaning, depending upon the locations and density of heliostat placement. These zones determine what type of mirror washing machine can be used for the heliostats in the zone. The Near Tower Zone (NTZ) consists of the area closest to the tower. The layout in this zone allows a vehicle to drive between the heliostats so that each heliostat can be accessed directly. The NTZ mirror washing machines are small and maneuverable. Each solar plant will require four NTZ mirror washing machines.

Heliostats beyond the NTZ cannot be accessed directly and must be reached with a crane. The heliostats that are more than about 400 meters from the tower will be cleaned using tractor-towed trailers with telescoping arms that can reach the heliostats from the limited areas in which vehicles can drive. Each machine will drive a short distance, park and anchor, and then extend its crane arm to clean as many heliostats as can be reached from its location. Each solar plant will require a total of 17 tractor-pulled trailers for cleaning heliostats outside the NTZ.

Two components contribute to emissions from site maintenance activities: combustion emissions from vehicles, and fugitive dust from driving over unpaved surfaces. Calculations of emissions from mirror cleaning activities are shown in Table 5.1B-11 and are summarized in Table 5.1-26.

TABLE 5.1-26
Emissions from Mirror Cleaning Activities

	Pollutant						
	NOx	**SO_2**	**CO**	**VOC**	**PM_{10}**	**$PM_{2.5}$**	**DPM***
Hourly, lb/hr	7.1	0.13	2.1	3.4	1.4	0.4	0.2
Daily, lb/day	74.9	1.3	22.0	35.6	14.7	3.7	2.5
Annual, ton/yr	13.7	0.24	4.0	6.5	2.7	0.7	0.5

* DPM: Diesel Particulate Matter

5.1.4.3.4 Criteria Pollutant Emissions: Plant Operation

The calculation of maximum facility emissions shown in Table 5.1-27 is based on the boiler emission rates shown in Table 5.1-22, the fuel use limitations in Table 5.1-20, and the following assumptions:

- Although the auxiliary, startup and nighttime preservation boilers are unlikely to be operated at the same time, a worst-case assumption is that boiler operations occur simultaneously.
- Each engine may be operated for maintenance and testing for up to 30 minutes on a single day and up to 50 hours per year. Although it is highly unlikely that all engines will be tested at the same time, the analysis of maximum hourly emissions during emergency engine testing assumes that all of the engines may be tested at the same time. Engines will not be tested on a day when the auxiliary boilers are operating.

Mirror cleaning will occur at night and will overlap only with operation of the nighttime preservation boilers.

Hourly, daily, and annual emissions from the new facility are shown in Appendix 5.1B, Table 5.1B-12. The maximum hourly, daily, and annual emissions, summarized in Table 5.1-27, are used in the air dispersion modeling to calculate the maximum potential ground-level concentrations contributed by the project to the ambient air.

TABLE 5.1-27
Maximum Emissions from New Equipment

	Pollutant				
Emissions/Equipment	**NOx**	**SO_2**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**
Maximum Hourly Emissions[a]					
Boilers	38.1	7.4	119.7	18.6	17.6
Emergency Engines	41.6	0.04	5.9	1.0	0.4
Diesel Fire Pump Engines	1.9	<0.01	1.2	0.1	0.1
WSACs	—	—	—	—	<0.01
Total, pounds per hour	**43.5**	**7.4**	**119.7**	**18.6**	**17.6**

TABLE 5.1-27
Maximum Emissions from New Equipment

	Pollutant				
Emissions/Equipment	**NOx**	**SO_2**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**
Maximum Daily Emissions[b]					
Boilers	242.6	35.6	738.4	104.1	88.5
Emergency Engines	41.6	0.04	5.9	1.0	0.4
Diesel Fire Pump Engines	1.9	<0.01	1.2	0.1	0.1
WSACs	—	—	—	—	0.1
Total, pounds per day	**242.6**	**35.6**	**738.4**	**104.1**	**88.5**
Maximum Annual Emissions					
Boilers	10.2	1.8	29.8	4.7	4.4
Emergency Engines	2.1	<0.01	0.3	0.05	0.02
Diesel Fire Pump Engines	0.1	<0.01	0.1	0.01	0.01
WSACs	—	—	—	—	0.01
Total, tons per year	**12.3**	**1.8**	**30.2**	**4.8**	**4.4**

[a] Boilers and engines will not operate during the same hour (see Table 5.1B-12, Appendix B). Maximum hourly NOx emissions occur during engine testing; maximum hourly emissions of other pollutants occur during boiler operations.

[b] Engine testing will occur only on days when the auxiliary boilers do not operate (see Table 5.1B-12, Appendix B). Maximum daily emissions occur on a day when the auxiliary boilers undergo cold startup.

5.1.4.3.5 Greenhouse Gas Emissions

Direct emissions of GHGs from the project are presented in Table 5.1-28. Carbon dioxide, nitrous oxide, and methane emissions are based on default emission factors for boilers and reciprocating internal combustion engines in the California Air Resources Board GHG Reporting Regulation.[6] The estimated emissions include sulfur hexafluoride leakage emissions from four circuit breakers at the switchyard and one generator circuit breaker at each power block. Emissions of methane, nitrous oxide, and sulfur hexafluoride have been converted to carbon dioxide equivalents using GHG warming potentials of 21, 310, and 23,900, respectively.

When calculating criteria pollutant emissions from the emergency generators, only the allowable hours per year of operation for testing and maintenance are used to determine maximum annual emissions; emergency use is not considered.[7] However, EPA guidance for determining potential to emit from emergency engines requires the inclusion of all operations: "EPA has no policy that specifically requires exclusion of 'emergency'… emissions." [8] In the absence of any permit limitation on annual emissions, EPA "believes that 500 hours is an appropriate default assumption for estimating the number of hours that

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[6] CARB, *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Appendix A*, December 2007

[7] CARB, *Risk Management Guidance for the Permitting of New Stationary Diesel-Fueled* Engines, October 2000; Footnote 3 to Table 1, Permitting Requirements for New Stationary Diesel-Fueled Engines ("The annual hours of operation for emergency standby engines include the hours of operation for maintenance and testing runs only.")

[8] USEPA, Letter from Steven C. Riva, Chief, Permitting Section, Air Programs Branch, to William O'Sullivan, Director, Division of Air Quality, New Jersey Department of Environmental Protection, February 14, 2006.

an emergency generator could be expected to operate under worst-case conditions."[9] Therefore, in the absence of any limiting permit condition, the calculation of PTE for GHG would have to assume that each emergency engine and fire pump engine will operate for 500 hours per year. The Applicant believes that operation of the emergency equipment will in fact not exceed 200 hours per year and is proposing an annual combined fuel use limit, equivalent to 200 hours per year of full-load operation of each unit, that will limit the GHG potential to emit for the emergency units and ensure that GHG emissions from the facility will be less than 100,000 tpy.

TABLE 5.1-28
Annual Emissions Of Greenhouse Gases

Pollutant	Emissions (metric ton/year)	CO_2 Equivalent (metric ton/yr)	CO_2 Equivalent (tons/yr)
CO_2	90,501	90,501	—
Nitrous Oxide	1.6	32.8	—
Methane	0.2	54.7	—
SF_6	2.0×10^{-3}	90.4	—
Total	**—**	**90,501**	**99,700**

5.1.4.3.6 Evaluation of Potential PSD Applicability

For the purposes of determining applicability of the PSD program requirements, the following regulatory procedure is used. Project emissions are compared with regulatory significance thresholds to determine whether the facility is major and thus may be subject to PSD review. If the facility emissions exceed these thresholds, it is a major facility. The comparison in Table 5.1-29 indicates that the project would not be a major source because its emissions of all pollutants are below the applicable major source thresholds.

TABLE 5.1-29
Comparison of Project Emissions With PSD Major Source Thresholds

Pollutant	Maximum Annual Project Emissions (tpy)	PSD Major Source Threshold (tpy)	Is Facility a Major Source?
NO_2	12.3	100	No
SO_2	1.8	100	No
CO	30.2	100	No
VOC	4.8	100	No
PM_{10}	4.4	100	No
$PM_{2.5}$	4.4	100	No
CO_2e	99,700	100,000	No

[9] USEPA, Memorandum from John S. Seitz, Director, OAQPS, to Regional Directors, re: "Calculating Potential to Emit (PTE) for Emergency Generators," September 6, 1995.

5.1.4.3.7 Non-Criteria Pollutant Emissions

Maximum hourly and annual noncriteria pollutant (toxic air contaminant, or TAC) emissions were estimated for the proposed boilers, emergency generators, emergency fire pumps, and partial dry cooling systems (WSACs). Maximum proposed TAC emissions for the boilers are shown in Table 5.1-30, and were calculated from the heat input rates (in MMBtu/hr and MMBtu/yr) shown in Table 5.1-20 and Table 5.1-21, EPA emission factors (in lb/MMscf), and the nominal higher heating value for the natural gas of 1020 Btu/scf.

Because diesel particulate matter is regulated by the State of California as a TAC, all of the PM_{10} emissions from the diesel emergency engines and diesel fire pump engines are also included. (These are shown in Table 5.1-18, with supporting calculations shown in Appendix 5.1B, Tables 5.1B-4 through B-7.) The ambient impact of these non-criteria pollutant emissions is determined by the potential health risks calculated in the screening health risk assessment (see Section 5.1.6.4).

Detailed calculations of the TAC emissions from the facility are shown in Appendix 5.1B, Tables 5.1B-15 and 5.1B-16. TAC emissions from the WSACs are negligible, as shown in Table 5.1B-17 of Appendix 5.1B.

As emissions of each individual federally-regulated hazardous air pollutant (HAP) are below 10 tons per year and total HAP emissions are below 25 tons per year, the project is an area source of HAPs. Compliance with the applicable area source NESHAPs is discussed in Section 5.1.6.1.

TABLE 5.1-30
Summary of Toxic Air Contaminant Emissions from Project Operation

	Maximum Proposed Emissions (total, all units)	
Compound	**lb/hr**	**tpy**
Boilers[a]		
Acetaldehyde	$3.2x10^{-3}$	$8.5x10^{-4}$
Acrolein	$2.8x10^{-3}$	$7.6x10^{-4}$
Benzene	$6.0x10^{-3}$	$1.6x10^{-3}$
Ethylbenzene	$7.0x10^{-3}$	$1.9x10^{-3}$
Formaldehyde	$1.3x10^{-2}$	$3.4x10^{-3}$
Hexane	$4.6x10^{-3}$	$1.2x10^{-3}$
Naphthalene	$1.0x10^{-3}$	$2.5x10^{-4}$
Polycyclic Aromatics	$3.5x10^{-4}$	$8.3x10^{-5}$
Propylene	$6.6x10^{-2}$	$3.8x10^{-2}$
Toluene	$2.7x10^{-2}$	$7.4x10^{-3}$
Xylene	$2.0x10^{-2}$	$5.5x10^{-2}$
Emergency Engines[b]		
Diesel Particulate Matter	0.43	$2.0x10^{-2}$

TABLE 5.1-30
Summary of Toxic Air Contaminant Emissions from Project Operation

	Maximum Proposed Emissions (total, all units)	
Compound	**lb/hr**	**tpy**
Fire Pump Engines[b]		
Diesel Particulate Matter	0.13	5.0×10^{-3}
Mirror Cleaning[c]		
Diesel Particulate Matter	2.5	0.5
Total HAPs[d]		2.3×10^{-2}

[a] Emission factors obtained from Ventura County APCD. See Tables 5.1B-14 through B-16.

[b] All PM_{10} emissions from Diesel engines are TACs.

[c] From Table 5.1-26.

[d] Propylene and Diesel Particulate Matter are not HAPs.

5.1.4.3.8 Construction Emissions: Project Construction

There are two types of construction emissions: combustion emissions and fugitive dust. Combustion emissions come from the workers' vehicles, from heavy equipment (both stationary and mobile), and from delivery vehicles. Fugitive dust comes from moving, disturbing, and traveling over the work site and roads and from windblown dust sources. Other activities that create dust include scraping and grading of the site, earth moving, and the movement of various construction vehicles around the site. A concrete batch plant will also be operated for about 12 months of the 29-month construction period. Although emissions from the batch plant will be minimized by powering the equipment with electric power instead of diesel-powered generators, the storage piles and transfer activities will be a potential source of fugitive dust.

The construction schedule is broken down into several activities: mobilization, during which the sites are set up to support the equipment and workers that will be on the site; clear and grub and road construction, during which vegetation is removed from the heliostat fields, the terrain is smoothed (not, however, graded, except for the power block areas), and plant and heliostat field access roads are constructed; heliostat erection; and power block, tower, and dry cooling system (air-cooled condenser) erection. Commissioning and testing will begin at the end of the construction period, when heliostat erection and power block construction are complete. Estimated land disturbance for major construction activities is summarized in Section 2.0, Project Description.

Construction equipment and vehicle exhaust emissions were estimated using equipment lists and construction scheduling information provided by the project design engineering firm, which are presented in Section 2.0, Project Description, and Appendix 5.1F. CARB's OFFROAD2010 and EMFAC2007 models were used to generate equipment-specific emission factors for all criteria pollutants for diesel-fueled construction equipment and for on-road vehicles, respectively. Assumptions used in calculating project construction emissions included a 29-month construction period with 40 hours per week of construction activity. Double-shift work schedules will be used during solar field assembly and installation activities and construction activities will continue around the clock when concrete is poured for the solar towers. A single-shift, 8- to 10-hour workday will be used for the remainder of the construction activities. The list of fueled equipment needed during each month of the construction effort (see Attachment 5.1F-1, Appendix 5.1F) served as the basis for estimating pollutant emissions throughout the term of construction and helped to identify the periods of probable maximum short-term emissions.

Fugitive dust emissions resulting from onsite soil disturbances were estimated using EPA AP-42 emission factors for activities including bulldozing and dirt-pushing, travel on paved and unpaved roads, material handling, and wind erosion to storage of aggregate materials. The mitigation measures of frequent watering and limiting speeds to 15 miles per hour were assumed to achieve a combined dust control efficiency of 85 percent for traveling on unpaved surfaces at the project site and temporary construction area activities. Emissions from on-road delivery trucks and worker commute trips were estimated using trip distribution information presented in Table 5.12-7 in Section 5.12 (Traffic and Transportation) and emission factors provided by CARB's EMFAC2007 model. The majority of the construction workers were assumed to commute to the proposed project site from locations in southern Nevada.

The short-term maximum emissions were calculated using Month 8 for construction equipment and Months 8/9[10] for fugitive dust. Activities in Month 8 include solar field assembly and installation, much of which will require double shifts. Annual emissions were based on the worst 12 consecutive months of the construction period, which were Months 6-17 of the 29-month schedule for combustion emissions, and Months 4-15 for fugitive dust.

Detailed construction emissions calculations are provided in Appendix 5.1F. Maximum daily project construction emissions are summarized in Table 5.1-31. Maximum annual project construction emissions are summarized in Table 5.1-32.

TABLE 5.1-31
Maximum Daily Project Construction Emissions, Pounds Per Day, Month 8 (Combustion), Months 8 and 9 (Fugitive Dust)

	NOx	CO	VOC	SOx	PM_{10}	$PM_{2.5}$
Onsite						
Construction Equipment (including batch plant)	349.8	181.2	25.9	0.6	86.0	25.8
Fugitive Dust	—	—	—	—	104.9	12.0
Offsite						
Worker Travel, Truck Deliveries	1,357.8	2,778.0	345.9	1.5	55.4	42.9
Total	1,708	2,959	372	2.2	246	81

[10] Months 8 and 9 have equal emissions.

TABLE 5.1-32
Maximum Annual Onsite Construction Emissions, Tons Per Year

	NOx	CO	VOC	SOx	PM_{10}	$PM_{2.5}$	GHG*
Onsite							
Construction Equipment	31.2	16.6	2.3	0.06	3.8	1.7	7,781
Fugitive Dust	—	—	—	—	14.1	1.5	—
Offsite							
Worker Travel, Truck Deliveries	30.9	302.3	32.3	0.01	1.5	1.0	2,308
Total	62.2	319	34.5	0.1	14.1	3.7	10,089

*GHG emissions shown as total MT over the 29-month construction period.

5.1.4.4 Emissions and Fuel Use Monitoring

The auxiliary boilers will be equipped with continuous emissions monitoring systems (CEMS) to measure and record emissions of NOx and oxygen, as required under 40 CFR Parts 60 and 75. The fuel flow rate (in MMscf) and oxygen levels for each of the boilers will be monitored continuously and permanently recorded.

Operating hours and fuel use will also be monitored and recorded for each of the emergency diesel engines and fire pump engines.

5.1.4.5 Air Quality Impact Analysis

The air quality impact analysis for the project evaluates the emissions presented above in ambient air dispersion modeling and health risk assessments. These analyses are presented in this section.

5.1.4.5.1 Air Quality Modeling Methodology

An assessment of impacts from the project on ambient air quality was conducted using EPA-approved air quality dispersion models. These models use a mathematical description of atmospheric dispersion to simulate the actual processes by which emissions are transported to potential ground-level impact areas. A detailed description of the methodology is provided in the Ambient Air Quality Modeling Protocol and follow-up correspondence with the CEC staff, which are included as Appendix 5.1H.

Using conservative assumptions, dispersion modeling was used to determine the maximum ground-level impacts of the project. The results were compared with state and federal ambient air quality standards. If the standards are not exceeded in the analysis, then the facility will cause no exceedances under any operating or ambient conditions, at any location, under any meteorological conditions. In accordance with the air quality impact analysis guidelines developed by EPA[11] and CARB[12], the ground-level impact analysis includes the following assessments:

- Impacts in simple, intermediate, and complex terrain;

11 EPA. Guideline on Air Quality Models, 40 CFR Part 51, Appendix W.
12 ARB. Reference Document for California Statewide Modeling Guideline, April 1989.

- Aerodynamic effects (downwash) due to nearby building(s) and structures; and
- Impacts from inversion breakup (fumigation).

Simple, intermediate, and complex terrain impacts were assessed for all meteorological conditions that would limit the amount of final plume rise. Plume impaction on elevated terrain, such as on the slope of a nearby hill, can cause high ground-level concentrations, especially under stable atmospheric conditions. Another dispersion condition that can cause high ground-level pollutant concentrations is caused by building downwash. Downwash can occur when wind speeds are high and a sufficiently tall building or structure is in close proximity to the emission stack. This can result in building wake effects where the plume is drawn down toward the ground by the lower pressure region that exists in the lee (downwind) side of the building or structure.

Fumigation conditions occur when the plume is emitted into a layer of stable air (inversion) that then becomes unstable from below, resulting in a rapid mixing of pollutants out of the stable layer and towards the ground in the unstable layer underneath. The low mixing height that results from this condition allows little diffusion of the stack plume before it is carried downwind to the ground. Although fumigation conditions are short-term, rarely lasting as long as an hour, relatively high ground-level concentrations may be reached during that period. Fumigation tends to occur under clear skies and light winds, and is more prevalent in summer.

The basic model equation used in this analysis assumes that the concentrations of emissions within a plume can be characterized by a Gaussian distribution about the centerline of the plume. Concentrations at any location downwind of a point source such as a stack can be determined from the following equation:

$$C(x,y,z,H) = \left(\frac{Q}{2\pi\sigma_y\sigma_z u}\right) * \left(e^{-1/2(y/\sigma y)^2}\right) * \left(\left[e^{-1/2(z-H/\sigma_z)^2}\right] + \left\lfloor e^{-1/2(z+H/\sigma_z)^2}\right\rfloor\right)$$

Where:

C = the concentration in the air of the substance or pollutant in question

Q = the pollutant emission rate

σ_y,σ_z = the horizontal and vertical dispersion coefficients, respectively, at downwind distance x

u = the wind speed at the height of the plume center

x,y,z = the variables that define the 3-dimensional Cartesian coordinate system used; the downwind, crosswind, and vertical distances from the base of the stack

H = the height of the plume above the stack base (the sum of the height of the stack and the vertical distance that the plume rises due to the momentum and/or buoyancy of the plume)

Gaussian dispersion models are approved by EPA for regulatory use and are based on conservative assumptions (i.e., the models tend to over-predict actual impacts by assuming steady-state conditions, no pollutant loss through conservation of mass, no chemical reactions, etc.). The EPA models were used to determine if ambient air quality standards would be exceeded, and whether a more accurate and sophisticated modeling procedure would be warranted to make the impact determination. The following sections describe:

- Model selection
- Refined air quality impact analysis
- Existing ambient pollutant concentrations and preconstruction monitoring
- Results of the ambient air quality modeling analyses

5.1.4.5.2 Model Selection

The air quality impact analyses were performed using the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) modeling system, also known as AERMOD (version 11059). The AERMOD modeling system includes a steady-state, multiple-source, Gaussian dispersion model designed for use with stack emission sources situated in terrain where ground elevations can exceed the stack heights of the emission sources (i.e., complex terrain). The model is capable of estimating concentrations for a wide range of averaging times (from 1 hour to 1 year). The AERMOD modeling system includes two preprocessors in addition to the dispersion model itself: AERMET and AERMAP. AERMET is a meteorological preprocessor, while AERMAP is a terrain preprocessor that characterizes terrain and generates receptor grids. Inputs required by the AERMOD modeling system include the following:

- Model options
- Meteorological data
- Source data
- Receptor data

Model options refer to user selections that account for conditions specific to the area being modeled or to the emissions source that needs to be examined. Examples of model options include use of site-specific vertical profiles of wind speed and temperature; consideration of stack and building wake effects; and time-dependent exponential decay of pollutants. The model supplies recommended default options for the user for some of these parameters.

AERMOD uses hourly meteorological data to characterize plume dispersion. The representativeness of the data is dependent on the proximity of the meteorological monitoring site to the area under consideration, the complexity of the terrain, the exposure of the meteorological monitoring site, and the period of time during which the data are collected. The meteorological data set used in this analysis combined surface meteorological data (e.g., wind speed and direction, temperature) from the Pahrump, Nevada, monitoring station, surface data (cloud cover) from Henderson, Nevada, and upper air data from Elko, Nevada.

For the purposes of modeling, a stack height beyond what is required by good engineering practices (GEP) is not allowed (40 CFR Part 60 §51.164). However, this requirement does not place a limit on the actual constructed height of a stack. GEP as used in modeling analyses is the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles. In addition, the GEP stack height modeling restriction assures that any required regulatory control measure is not compromised by the effect of that portion of the stack that exceeds the GEP height. The EPA guidance ("Guideline for Determination of Good Engineering Practice Stack Height," Revised 6/85) for determining GEP stack height indicates that GEP is the greater of 65 meters or H_g, where H_g is calculated as follows:

$$H_g = H + 1.5L$$

Where:

H_g = Good Engineering Practice stack height, measured from the ground-level elevation at the base of the stack

H = height of nearby structure(s) measured from the ground-level elevation at the base of the stack

L = lesser dimension, height or maximum projected width, of nearby structure(s)

The boiler stack heights, at between 90 and 120 feet, are less than the GEP limit of 65 meters (213 feet). Stack heights therefore do not need to be adjusted for GEP.

5.1.4.5.3 Receptor Grid Selection and Coverage

Receptor and source base elevations were determined from U.S. Geological Survey (USGS) National Elevation Dataset (NED) data in the GeoTIFF format at a horizontal resolution of 1 arc-second (approximately 30 meters). All coordinates were referenced to UTM North American Datum 1983 (NAD83), Zone 11. The AERMOD receptor elevations were interpolated among the Digital Elevation Map (DEM) nodes according to standard AERMAP procedures. For determining concentrations in elevated terrain, the AERMAP terrain preprocessor receptor-output (ROU) file option was chosen; hills were not imported into AERMOD for CTDM-like processing.

Cartesian coordinate receptor grids were used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impact locations. A 250-meter resolution coarse receptor grid was developed and extended outwards at least 5 km.[13] For the full impact analyses, a nested grid was developed to fully represent the maximum impact area(s). This grid has 25-meter resolution along the facility fence-line in a single tier of receptors composed of four segments extending out to 100 meters from the fence line, 100-meter resolution from 100 meters to 1,000 meters from the fence line, and 250-meter spacing out to 5 km from the fence line. Additional refined receptor grids with 25-meter resolution were placed around the maximum first-high and maximum second-high coarse grid impacts and extended out 500 meters in all directions. Concentrations within the facility fence line were not calculated. The regions imported in Geographical Coordinates for the USGS NED data are bounded as follows:

- Southwest corner: Lat: 35.88, Lon: -116.04
- Northeast corner: Lat: 36.11, Lon: -115.75

The analysis included receptors in California and Nevada.

[13] Although the modeling protocol indicated that the coarse receptor grid would extend up to 10 km from the fence line, the maximum impacts were very close to the project and a larger grid was not needed to identify significant impact areas.

5.1.4.5.4 Meteorological Data Selection

EPA defines the term "onsite data" to mean data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may have a significant impact on air quality. Representativeness has been defined in the PSD Monitoring Guideline as data that characterize the air quality for the general area in which the proposed project would be constructed and operated. The meteorological data requirement originates in the Clean Air Act at Section 165(e)(1), which requires an analysis "of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility."

This requirement and EPA's guidance on the use of onsite monitoring data are also outlined in the On-Site Meteorological Program Guidance for Regulatory Modeling Applications.[14] The representativeness of the data depends on (a) the proximity of the meteorological monitoring site to the area under consideration, (b) the complexity of the topography of the area, (c) the exposure of the meteorological sensors, and (d) the period of time during which the data are collected.

Hourly surface meteorological data (e.g., hourly wind speed and direction and temperature) have been obtained from Pahrump, Nevada, for calendar years 2006 through 2010. Cloud cover data from the Henderson Airport, near Las Vegas, were used as no cloud cover data are collected at the Pahrump station. Upper air data were recorded at Elko, Nevada. The Pahrump, Nevada, monitoring station is 18 miles (28 km) from the project site, and is located in the same valley and at a similar elevation on the same high desert plateau. Therefore, the met data station meets criteria (a), (b), and (c) above. In addition, the use of 5 years of meteorological data ensures adequate representation of temporal variation. Based on these considerations, the Applicant believes that the proposed meteorological data are representative of conditions at the project site.

Representativeness is best evaluated when sites are climatologically similar, as are the project site and the Pahrump meteorological monitoring station. The Pahrump meteorological monitoring station is near the HHSEGS site (distance between the two locations is approximately 18 miles with no significant intervening terrain features), and the same large-scale topographic features located to the east and south that influence the meteorological data monitoring station influence the project site in the same manner.

The values for the surface characteristics of albedo, Bowen Ratio, and surface roughness appropriate to the area around the Pahrump meteorological monitoring station have been obtained from AERSURFACE[15], designed to aid in obtaining realistic and reproducible surface characteristic values for AERMET, following EPA guidance. AERSURFACE uses land cover data from the U.S. Geological Survey National Land Cover Data 1992 archives, meaning that the land cover data used to develop surface characteristics for the Pahrump area reflect conditions in 1992, before extensive development took place in the area. The area within one kilometer of the met station, which is used in the AERMOD modeling system to define surface characteristics, has seen some isolated development to the south, the west, and north-northeast. The rest of the area surrounding the met station remains undeveloped. The prevailing winds in the area are from the south through southeast, so only the development

[14] EPA, *Supplement A to the Guideline on Air Quality Models (Revised)*, 1987.

[15] AERSURFACE is a surface characteristics preprocessor that is part of the AERMOD modeling system.

to the south would be likely to have any significant influence on meteorological conditions monitored at the station. Because of the sparse distribution and the regular shapes of these buildings, the impacts of these buildings on the monitor are expected to be minimal. Finally, the surface characteristics associated with the Pahrump met data reflect conditions consistent with "shrubland (arid region)" and are in no way similar to residential or commercial surface roughness values. Therefore, the surface characteristics associated with the Pahrump meteorological station data appropriately reflect surface characteristics at the project site.

Upper air meteorological data are taken from soundings obtained at Elko, Nevada, located approximately 335 miles northeast of the project site. The nearest upper air station to the project site is located at Desert Rock, Nevada. For the period 2006 through 2010, however, the upper air data from Desert Rock are incomplete—approximately 15% missing data, which exceeds the 10% EPA data completeness threshold.

The next closest upper air station is at Miramar Naval Air Station, California. However, Miramar is a coastal site, while Elko is an inland desert site and as such is climatologically more similar to the project site.

5.1.4.5.5 Ambient Background Data Selection

Background ambient air quality data for the project area from the monitoring site most representative of the conditions that exist at the HHSEGS site were used to represent regional background concentrations. Table 5.1-33 shows the monitoring stations that provide the most representative ambient air quality background data.[16]

TABLE 5.1-33
Representative Background Ambient Air Quality Monitoring Stations

Pollutant(s)	Monitoring Station	Distance to Project Site
Ozone, PM_{10}, $PM_{2.5}$	Jean, NV (Clark County)	34 miles
CO	Barstow, CA (San Bernardino County)	97 miles
NO_2, SO_2	Trona, CA (San Bernardino County)	82 miles
Lead	San Bernardino, CA (San Bernardino County)	150 miles

Although the PM_{10} monitoring site at Pahrump, Nevada, is closer to the project site than the Jean station, as discussed above, the Pahrump data are strongly affected by local windblown dust, and are therefore not representative of regional background concentrations.

As discussed in Section 5.1.2, NO_2 data were collected at Jean until 2007. More current NO_2 data from Trona are used to conservatively overestimate background NO_2 concentrations at the project site. Background data representative of conditions at the project site are summarized in Table 5.1-34.

[16] Selection of the background monitoring stations is also discussed in Section 5.1.3.4.

TABLE 5.1-34
Representative Background Concentrations in the Project Area

Pollutant	Averaging Time	2008	2009	2010
Trona (San Bernardino County)				
NO_2	1 hour (1st high)	117	92.1	97.8
	1 hour (98th percentile)[b]	80.8	73.3	79.0
	Annual	7.5	7.5	—[a]
SO_2	1 hour	93.6	28.6	31.2
	3 hours	15.6	20.8	23.4
	24 hours	13.1	7.9	10.5
	Annual	2.7	2.7	—
Barstow (San Bernardino County)				
CO	1 hour	1,750	1,125	1,125
	8 hours (CA. 1st high)	1,333	1,000	—
Jean, NV				
PM_{10}	24 hours	96	81.3	49
	Annual (CA)	14	12.4	8.5
$PM_{2.5}$	24 hours (3-yr avg, 98th Percentile)[b,c]	10.3	11.2	11.4
	Nat'l 3-Year Avg AAM [d]	4.9	4.0	3.5

[a] Insufficient data.

[b] Calculated from http://www.epa.gov/mxplorer/index.htm, "Query Concentrations" function

[c] See Table 5 of the modeling protocol in Appendix 5.1H.

[d] Annual arithmetic mean

5.1.4.5.6 Construction Impacts

Section 5.1.4.3.8 describes the development of project emissions estimates over the planned 29-month construction period. An Excel workbook was created to estimate pollutant emissions from construction activities. Emissions from worker commuter trips to and from the project site and heavy trucks delivering materials to and from the site during specific construction activities were also included (see Appendix 5.1F).

Based on information provided by the engineering design contractor and the emission estimates in Appendix 5.1F-1, the peak month in terms of air pollutant emissions is expected to be the eighth month of construction (Month 8). Worst-case modeling was conducted for short-term averaging times using all combustion emissions from all construction equipment from Month 8 and dust emissions from activities in Months 8 and 9 (see Table 5.1-31 and Table 5.1-32). Construction activities were assumed to occur during a 20-hour work day during these periods, reflecting double-shift activity. The annual emissions were modeled for Months 6–17 for combustion emissions and Months 4–15 for fugitive dust emissions after a determination that these consecutive 12-month periods will have higher levels of construction activity and exhaust and dust emissions than any others over the full 29 months of construction. The construction impact modeling was performed with no downwash. The emission sources for the construction site were grouped into three categories: exhaust emissions, construction dust emissions, and windblown dust emissions. The vehicle exhaust and construction dust emissions were modeled as 26 volume sources with a vertical dimension of 6 meters. Among the 26 volume sources, 24 were located completely within the project boundary and were used to represent the construction dust and combustion exhaust sources from the project site. Two volume sources were located within both the laydown area and the project fence line and were used to represent construction dust and combustion exhaust sources in those areas. Based on the width of the construction area, the horizontal dimension for each volume source was set to 563.8 meters, with sigma-y = 131.1 meters. The fugitive dust emissions from disturbed areas were represented for modeling purposes as area sources. To assess impacts from fugitive dust, the project site and the laydown area were modeled as one single area source covering a combined disturbed area of 2,960 acres.[17] The effective plume height for these two area sources was set at 0.5 meters in the modeling analysis.

As discussed in the modeling protocol, the Ozone-Limiting Method (OLM) option of AERMOD was used to account for the role of ambient ozone levels on the atmospheric conversion rate of NOx emissions (initially mostly in the form of nitric oxide) to NO_2 (the pollutant addressed by ambient standards). Hourly ozone measurements at the Jean, Nevada, monitoring station during the same 5 years of the meteorological input data set were used to support the OLM calculations. Modeling results are shown in Table 5.1-35.

Table 5.1-35 shows that the worst-case background concentration of 24-hour average PM_{10} is already above the state standards, while background concentrations of PM_{10} and $PM_{2.5}$ are below the state and federal standards. The project's modeled annual PM_{10} and $PM_{2.5}$ impacts are small relative to the background; the annual $PM_{2.5}$ impact is barely above the federal threshold for significance of 0.3 µg/m^3.

The project's construction emissions will result in potentially significant impacts for PM_{10} and $PM_{2.5}$. Emissions and modeled impacts from construction activities are not unusual compared with those from other construction projects. Appendix 5.1F describes the mitigation measures that will be used during construction to minimize these impacts.

The data summarized in Table 5.1-35 show that construction emissions will not cause new exceedances of any other state or federal air quality standards, including the state and federal 1-hour NO_2 standards.

TABLE 5.1-35
Modeled Maximum Impacts During Project Construction

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m^3)	Maximum Background Concentration (µg/m^3)	Total Concentration[a] (µg/m^3)	NAAQS (µg/m^3)	CAAQS (µg/m^3)
NO_2	1-hr (highest)	100.1	117	217	—	339
	1-hr (98th percentile)	85.8	80.8	167	188	—
	Annual	3.4	7.5	11	100	57
SO_2	1-hr	0.2	93.6	94	196	655
	3-hr	0.2	23.4	24	1300	—
	24-hr	0.05	13.1	13	—	105
	Annual	0.01	2.7	2.7	80	—
CO	1-hr	62.9	1,750	1,813	40,000	23,000
	8-hr	26.7	1,333	1,360	10,000	20.000

[17] As discussed in Section 5.1.4.3.8, not all of the project site will be disturbed. This assessment of fugitive dust impacts is conservative in that it overestimates the disturbed area.

TABLE 5.1-35
Modeled Maximum Impacts During Project Construction

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Maximum Background Concentration ($\mu g/m^3$)	Total Concentration[a] ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	CAAQS ($\mu g/m^3$)
PM_{10}	24-hr	24.2	96	120	150	50
	Annual	1.4	14	15	—	20
$PM_{2.5}$	24-hr[b]	5.1	11.4	17	35	—
	Annual[c]	0.3	4.9	5.2	15.0	12

[a] Total concentrations shown in this table are the sum of the maximum predicted impact and the maximum measured background concentration. Because the maximum impact is unlikely to occur at the same time as the maximum background concentration, the actual maximum combined impact will be lower.

[b] Background concentration shown is the three-year average of the 98th percentile values, in accordance with the form of the federal standard. See Table 5.1-34, footnote c.

[c] Background concentration shown is the three-year average of the annual arithmetic mean, in accordance with the form of the standard.

5.1.4.5.7 Operational Impacts

Normal Plant Operations

The results of the AERMOD assessment for normal plant operations are summarized in Table 5.1-36. Listed below are the operating assumptions used in developing the emission rates for each emissions unit and averaging period. Emission rates and stack parameters used in modeling impacts during normal plan operations are shown in Table 5.1D-2, Appendix 5.1D.

1-hour averages

- All emergency engines operational for testing; OR
- All boilers operating at full load.

3-hour and 8-hour averages

- All emergency engines operational for testing; OR
- All boilers operating at full load.

24-hour averages

- All boilers operating with maximum daily emissions and WSACs in operation; OR
- Startup and nighttime preservation boilers operating at full load and all emergency engines operational for testing.

Annual Averages

- All equipment included.
- For all pollutants, maximum annual emissions used to calculate average hourly emission rate.

The highest 1-hour NO_2 impacts occur during engine testing. The highest impacts for other pollutants and averaging periods occur during boiler operation.

The modeling results in Table 5.1-36 show that only 1-hour NO_2 and SO_2 impacts exceed the interim PSD SILs—all other modeled impacts during all operating scenarios are below the significant impact levels.

Startup Impact Analysis

As discussed in Section 5.1.4.2, the boilers will need to undergo occasional cold startups, during which they may operate for extended periods at low loads with, in some cases, emission rates that are slightly higher than emissions during normal operations. The ambient air quality impact analysis included assessments of potential air quality impacts of boiler startups. To simplify the analyses and make sure they are conservative, the following scenarios were evaluated:

- Auxiliary boiler startup: One unit at each power block is in startup simultaneously. No other boilers or engines are operating. Although startup times for the auxiliary boilers will not exceed 6 hours, 8-hour CO emission rates reflect 8 hours of startup to be conservative.
- Startup boiler startup: Startup boiler at each power block is in startup simultaneously. Startups may occur while nighttime boilers are in operation. Although startup times for the startup boilers will not exceed 5 hours, 8-hour CO emission rates reflect 8 hours of startup to be conservative.
- Nighttime boiler startup: Nighttime boiler at each power block is in startup simultaneously. Startups may occur while auxiliary boilers are in operation. Although startup times for the nighttime preservation boilers will not exceed 4 hours, 8-hour CO emission rates reflect 8 hours of startup to be conservative.

Emission rates and stack parameters for the boiler startup analyses are shown in Table 5.1D-3, Appendix 5.1D. Results of the startup impact analysis are shown in Table 5.1-36 along with results for other operating conditions. The highest startup impacts occur during startup of the auxiliary boilers.

Ambient Impacts During Hot Standby Operation

On some days when cloudy weather is anticipated, the auxiliary boilers may be operated on hot standby starting earlier in the day so that they will be available to augment the solar operations when solar energy diminishes or during transient cloudy conditions. When operating in hot standby mode, the boilers would operate at about 5 percent of their rated heat input rate. As discussed earlier, emissions during hot standby will be very low because of the low heat input. However, because of the low potential stack velocities, this operating mode has been included in the ambient air quality assessment. The modeling analysis for this operating mode assumes that all six boilers are on hot standby simultaneously for up to 8 hours. This assumption conservatively overestimates impacts during this operating mode. Emission rates and stack parameters used in evaluating impacts during hot standby operation are shown in Table 5.1D-4, Appendix 5.1D. Modeled impacts are shown in Table 5.1-36.

TABLE 5.1-36
Summary of Modeling Results for Facility Operations

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$) Normal Operation	Startup Operation	Hot Standby Operation	Inversion Breakup Fumigation	PSD Significant Impact Level ($\mu g/m^3$)
NO_2	1-hr (max)	220[a]	35.1	59.7	17.3	7.5[e]
	1-hr (98th pct)	166[a]	30.5	51.8	n/a[c]	—
	Annual	0.1	n/a[b]	n/a[b]	n/a[d]	1.0
SO_2	1-hr	19.0	1.1	1.2	3.4	7.8[e]
	3-hr	8.7	0.6	0.8	2.9	25
	24-hr	0.5	n/a[b]	n/a[b]	1.2	5
	Annual	0.01	n/a[b]	n/a[b]	n/a[d]	1.0
CO	1-hr	261.7	94.9	101.0	52.9	2000
	8-hr	64.3	39.0	40.6	33.1	500
PM_{10}	24-hr	1.1	n/a[b]	n/a[b]	0.7	5
	Annual	0.03	n/a[b]	n/a[b]	n/a[d]	1
$PM_{2.5}$	24-hr	1.1	n/a[b]	n/a[b]	0.7	1.2
	Annual	0.03	n/a[b]	n/a[b]	n/a[d]	0.3

[a] Highest 1-hour average NO_2 impacts occur during emergency engine testing; maximum impacts for other pollutants and averaging periods occur during boiler operation. Maximum 1-hour NO_2 impact during normal boiler operations is 80 $\mu g/m^3$; 98th percentile NO_2 impact during normal boiler operation is 48.7 $\mu g/m^3$. All NO_2 results except fumigation reflect ozone limiting.

[b] Startup and hot standby operations are short-term operating modes and do not affect averaging periods longer than 8 hours.

[c] Inversion breakup fumigation is modeled using screening models so no 98th percentile value can be produced.

[d] Inversion breakup fumigation is a short-term phenomenon and does not affect annual impacts.

[e] These are interim SILs and have not been formally adopted by EPA.

Inversion Breakup Fumigation Modeling

Inversion breakup fumigation occurs when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Under these conditions, an exhaust plume may be drawn to the ground, causing high ground-level pollutant concentrations. Although fumigation conditions rarely last as long as 1 hour, relatively high ground-level concentrations may be reached during that time. For this analysis, fumigation was assumed to occur for up to 90 minutes, per EPA guidance.

The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Guidance from EPA[18] was followed in evaluating fumigation impacts. The maximum fumigation impact from this analysis, which is shown in more detail in Table 5.1D-5, Appendix 5.1D, showed that impacts under fumigation conditions are expected to be lower than the maximum concentrations calculated by AERMOD under normal operations (including downwash conditions). Inversion breakup impacts are also shown in Table 5.1-36.

[18] EPA-454/R-92-019, "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised."

For all pollutants, fumigation impacts are lower than the maximum predicted impacts from normal operations and meteorological conditions.

5.1.4.5.8 Demonstration of Compliance

The maximum facility impacts calculated from the modeling analyses described above are summarized in Table 5.1-36 above. The highest modeled short-term NO_2 impacts are expected to occur during engine testing; the highest impacts for other pollutants and averaging periods occur under normal boiler operations. To determine the project's air quality impacts, the modeled concentrations are added to the highest reported background ambient air concentrations and then compared to the applicable ambient air quality standards. The highest reported background ambient concentrations were discussed in Section 5.1.3.4 and the monitored concentrations during the past three years are shown in Table 5.1-37. More detailed discussions of why the data collected at these stations are representative of ambient concentrations in the vicinity of the project are provided in Sections 5.1.3.4 and 5.1.4.5.

TABLE 5.1-37
Summary of Results (Modeled Maximum Impacts plus Background)

Pollutant	Averaging Time	Project Impact (μg/m^3)	Background Concentration (μg/m^3)	Total Concentration (Project Impact plus Background) (μg/m^3)	NAAQS (μg/m^3)	CAAQS (μg/m^3)
NO_2	1-hr (max)	220.0	117	226*	—	339
	1-hr (98th ptl)	165.8	80.8	174*	188	—
	Annual	0.1	7.5	7.6	100	57
SO_2	1-hr	19.0	93.6	113	196	655
	3-hr	8.7	23.4	32	1300	—
	24-hr	0.5	13.1	14	—	105
	Annual	0.01	2.7	2.7	80	—
CO	1-hr	261.7	1,750	2,012	40,000	23,000
	8-hr	64.3	1,333	1,397	10,000	20.000
PM_{10}	24-hr	1.1	96	97.1	150	50
	Annual	0.03	14	14	—	20
$PM_{2.5}$	24-hr	1.1	11.4	12.5	35	—
	Annual	0.03	4.9	4.9	15.0	12

*Total concentrations shown for 1-hour NO_2 are modeled project impacts combined with concurrent hourly NO_2 monitoring data (Tier 4 analysis in Section 3.6 of the modeling protocol). All other totals shown are maximum modeled project impacts combined with maximum monitored background data from Table 5.1-34.

5.1.4.5.9 PSD Increment Consumption

The Prevention of Significant Deterioration (PSD) program was established to allow emission increases (increments of consumption) that do not result in significant deterioration of ambient air quality in areas where criteria pollutants have not exceeded the NAAQS. As discussed in Section 5.1.4.3, the project is not subject to PSD review.

5.1.4.5.10 Preconstruction Monitoring

Because HHSEGS is not subject to PSD review, EPA will not require preconstruction ambient air quality monitoring data for the purposes of establishing background pollutant concentrations in the impact area.

5.1.4.5.11 Commissioning Impacts

Commissioning emissions are quantified in Table 5.1B-18, Appendix 5.1B. Maximum emissions from each boiler are expected to occur during the cold start/tuning phase of commissioning, and during that period boiler operation and emissions are expected to be similar to those that occur during cold startups. Ambient impacts during boiler startups were evaluated above (see Table 5.1-36) and shown not to be expected to cause or contribute to any violations of the ambient air quality standards.

5.1.4.6 Screening Health Risk Assessment

The screening health risk assessment (SHRA) was conducted to determine expected impacts on public health of the noncriteria pollutant emissions from the operation of the boilers and emergency Diesel engines.[19] The SHRA was conducted in accordance with the OEHHA's "Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments" (October 2003).

The SHRA estimated the offsite potential Maximum Incremental Cancer Risk (MICR) at the point of maximum impact, at the location (e.g., residence) of the maximally exposed individual (MEI) and to the maximally exposed worker (MEW), and the potential long-term (chronic) and short-term (acute) non-carcinogenic health impacts from non-carcinogenic emissions. The CARB/OEHHA-approved Hotspots Analysis and Reporting Program (HARP) (Version 1.4d) was used to evaluate multipathway exposure to non-criteria pollutant emissions. The individual pollutant carcinogenic risks are assumed to be additive. Because of the conservatism (overprediction) built into the established risk analysis methodology, the actual risks will be lower than those estimated.

The SHRA utilized the following information:

- Inhalation cancer potency factors for the carcinogenic emissions
- Noncancer Reference Exposure levels (RELs) for determining chronic and acute non-carcinogenic health impacts
- One-hour and annual average emission rates for each non-criteria pollutant
- The modeled maximum offsite concentration of each non-criteria pollutant emitted

Many of the carcinogenic compounds also have non-carcinogenic health effects and are therefore included in the determination of both potential carcinogenic and noncarcinogenic effects. RELs are used as indicators of potential non-carcinogenic adverse health effects. RELs are generally based on the most sensitive adverse health effect reported and are designed to protect the most sensitive individuals. However, exceeding the REL does not automatically indicate a health impact. The OEHHA RELs were used to determine potential adverse health effects from noncarcinogenic compounds. A potential chronic health hazard index for each relevant non-carcinogenic pollutant is then determined by the ratio of the pollutant maximum annual average concentration to its respective REL. Similarly, a potential acute health hazard index for each relevant non-carcinogenic pollutant is determined by the ratio of the pollutant maximum one-hour average concentration to its

[19] The WSACs were not included in the screening HRA because their TAC emissions are negligible (see Table 5.1B-17, Appendix 5.1B).

respective REL. The individual indices are summed to determine the overall hazard index for the project. Because noncarcinogenic compounds target different internal systems or organs (e.g., respiratory system, nervous system, eyes), this sum is considered conservative.

The SHRA results are compared with the established risk management procedures for the determination of acceptability. The established risk management criteria include those listed below.

- If the MICR is less than one in one million, the facility risk is considered not significant.
- If the MICR is greater than one in one million but less than ten in one million and Toxics-Best Available Control Technology (T-BACT) has been applied to reduce risks, the facility risk is considered acceptable.
- If the MICR is greater than ten in one million but less than 100 in one million and there are mitigating circumstances that, in the judgment of a regulatory agency, outweigh the risk, the risk is considered acceptable.
- For non-carcinogenic effects, total hazard indices of one or less are considered not significant.
- For a hazard index greater than one, OEHHA, the CEC and the GBUAPCD may conduct a more refined review of the analysis and determine whether the impact is acceptable.

The SHRA includes the noncriteria pollutants listed above in Table 5.1-20. The receptor grid described earlier for criteria pollutant modeling was used for the SHRA. The potential health risks are presented in Table 5.1-38, and the detailed calculations are provided in Appendix 5.1E. The locations of the maximum modeled risks are shown in Appendix 5.1E, Figure 5.1E-1.

TABLE 5.1-38
Potential Health Risks from the Operation of the Project

	Project	Significance Thresholds	Significant?
Maximum Incremental Cancer Risk (MICR) at Point of Maximum Impact	0.39 in one million	10 in one million	No
MICR at Residential Receptor	0.15 in one million	1 in one million	No
Acute Inhalation Health Hazard Index: 1-hour	0.004	1.0	No
Acute Inhalation Health Hazard Index: 8-hour	0.004	1.0	No
Chronic Inhalation Health Hazard Index	0.0002	1.0	No

The acute and chronic health hazard indices are well below 1.0, and hence, are not significant. The MICR is 0.39 in one million, below the GBUAPCD's 1 in one million threshold for additional analysis and the ten in one million significance threshold for the project. The project will not pose a significant health risk at any location, under any weather conditions, under any operating conditions.

Potential health risks during construction are evaluated in Appendix 5.1F. This evaluation concludes that health risks during construction will not be significant.

5.1.5 Cumulative Effects

A CEQA cumulative impacts analysis examines potential cumulative air quality impacts that may result from the project and other reasonably foreseeable projects. Such an analysis is generally required only when project impacts are significant.

5.1.5.1 Cumulative Construction Impacts

Project construction will occur over a 29-month period. Impacts during construction will be localized, as discussed in Appendix 5.1F. Construction of the transmission and gas lines will occur concurrently with onsite construction, but most of the linears construction will occur at distances of more than 10 miles from the project site. Because impacts from linears construction are also expected be localized, it is unlikely that any cumulative construction impacts will occur with the exception of the construction of the linears that are closest to the project. Therefore any cumulative construction impacts will be temporary and localized and as such are not expected to be significant.

5.1.5.2 Cumulative Operational Impacts

To ensure that potential cumulative impacts of the project and other nearby projects are adequately considered, a cumulative impacts analysis will be conducted in accordance with the protocol included as Appendix 5.1G.

5.1.5.3 Greenhouse Gas Cumulative Effects Analysis

In 2006, the California Legislature adopted AB 32, the California Global Warming Solutions Act of 2006. This legislation started California on the path to reduce emissions of GHGs in California to 1990 levels. The principal regulated GHG is carbon dioxide, which is emitted primarily from the combustion of fossil fuels.

The legislation requires CARB to determine the 1990 levels, and to adopt regulatory mechanisms to bring California's emissions back down to those levels by 2020. The legislation does not require that individual facilities or sectors return to 1990 levels. It is expected that some sectors will achieve greater reductions than others.

It is unlikely that California's entire program will have a measurable impact on global climate change. Rather, it is asserted that California's effort, in conjunction with similar efforts worldwide, could reduce or even eliminate the negative impacts associated with global climate change.

It follows that no individual project, or even the cumulative effects of all of the reasonably foreseeable projects in California, will have a measurable impact on global climate change. However, new emissions of carbon dioxide will make it more difficult for the state to meet its goal of reducing GHG emissions to 1990 levels.

State agencies are developing the plans and regulations necessary to achieve the GHG emission reductions required by AB 32. The starting point of these plans is a projection of what emissions would be in 2020 if business went on as usual. A significant amount of new emissions in the "business as usual" scenario comes from increased demand for electricity in California. In the absence of established thresholds of significance or methodologies for assessing impacts, this analysis of GHG emission impacts consists of quantifying project-related GHG emissions, determining their significance in comparison to the goals of AB 32, and discussing the potential impacts of climate change within the state as well as strategies for minimizing those impacts.

Regulations already in place require that much of that increased demand be met by projects like HHSEGS, which generate energy that does not derive from the combustion of fossil fuels. The California legislature recently adopted Senate Bill 1X 2 (SB 2), which requires 33 percent of retail electricity sales to come from renewable resources by 2020. SB 2 also establishes interim targets for renewable generation to ensure that timely progress is made toward the 33 percent RPS goal, requiring that 75 percent of generation must come from within California by 2016. The HHSEGS project will help to further progress toward the SB 2 goals by providing a reliable, in-state source of renewable electricity that will come online before the 2016 interim deadline.

Most renewable energy facilities such as wind and solar are “intermittent resources,” meaning these resources are not available to generate in all hours and thus have limited operating capacity. For example, intermittent resources can be limited by meteorological conditions on an hourly, daily, and seasonal basis. In addition, the availability of intermittent resources is often unrelated to the load profile they serve. For example, some solar resources reach peak production around 12:00 noon, while the electrical demand sometimes peaks between 5:00 p.m. and 7:00 p.m. HHSEGS has the advantage over many other solar facilities of being able to provide electricity during the peak evening demand period through the use of the auxiliary boilers to augment the solar operation when solar energy diminishes or during transient cloudy conditions that impact the available solar energy.

HHESGS supports the State’s strategy to reduce fuel use and GHG emissions. Although the use of natural-gas-fired auxiliary boilers will result in GHG emissions, the overall GHG emission rate for the project will be below the EPS standard of 0.500 metric tons CO_2 per MWh and below the rates for comparably sized fossil-fueled projects. Table 5.1-39 compares the GHG emissions performance of HHSEGS with that of other types of power plants.

TABLE 5.1-39
Comparison of GHG Emissions Performance

Type of Power Plant	GHG Emissions Performance, MT CO_2/MW*
HHSEGS	0.060
Natural Gas Combined Cycle	0.370 to 0.430
California GHG Emissions Performance Standard (EPS)	0.500
Natural Gas-Fired Boiler	0.550 to 0.650
Natural Gas-Fired Peaking Turbine	0.550 to 0.900
Coal-Fired Boiler	~1.00

*All GHG emissions performance data except HHSEGS from Ivanpah FSA, Appendix Air-1, October 2009.

Further, even though it is possible to quantify how many gross GHG emissions are attributable to the project, it is difficult to determine whether this will result in a net increase of these emissions—and, if so, by how much—due to the displacement by the project of emissions from fossil generating resources. The loading order adopted in 2003 by the CEC and PUC prioritizes the use of generation from renewables, such as HHSEGS, over generation from fossil fuel resources. In addition, the CEC has predicted that as California moves towards an increased reliance on renewable energy, non-renewable energy sources will be curtailed or displaced."[20] Therefore, it would be speculative to conclude that greenhouse gas emissions from any given project will cause a cumulatively significant adverse impact.

Demand for electricity in California will not be affected by HHSEGS. Every megawatt-hour generated by the project, however, will displace a megawatt-hour that would otherwise have been generated by a more traditional (i.e., fossil-fuel-fired) source of electricity. HHSEGS will increase renewable generation and contribute to the state's efforts to move toward a high-renewable, low-GHG electricity system. HHSEGS is therefore expected to result in a net reduction in GHG emissions.

As directed by SB 97, the Resources Agency adopted Amendments to the CEQA Guidelines for greenhouse gas emissions (GHG CEQA Guidance) on December 30, 2009. On March 18, 2010, those amendments became effective.

The GHG CEQA Guidance included the following elements:

- Quantification of GHG emissions;
- Determination of whether the project may increase or decrease GHG emissions as compared to existing environmental setting;
- Determination of whether the project emissions exceed a threshold of significance determined by the lead agency;
- The extent to which the project complies with state, regional, or local plans for reduction or mitigation of GHGs; and
- Mitigation measures.

GHG emissions were quantified in Table 5.1-28. The discussion above supports a determination that the project can be expected to decrease GHG emissions as compared with the current situation. HHSEGS will provide more than 1,500 GWh of renewable generation that could replace aging, less-efficient, coal-fired and/or once-through cooled generating resources. The preceding discussion also demonstrates that GHG emissions from the project will be below the EPS, which is generally accepted as a threshold of significance for GHG emissions from electric generation facilities, and will further the state's progress toward its RPS and SB 2 goals. Because the GHG emissions are not expected to be significant, no additional mitigation is necessary.

[20] Commission Decision for the Ivanpah SEGS, CEC-800-2010-004 CMF, September 2010.

5.1.6 Consistency with Laws, Ordinances, Regulations, and Standards

This section considers consistency separately for federal, state, and local requirements.

5.1.6.1 Consistency with Federal Requirements

Prevention of Significant Deterioration Program

The PSD requirements apply, on a pollutant-specific basis, to any project that is a new major stationary source or a major modification to an existing major stationary source. A major source is a listed facility (one of 28 PSD source categories listed in the federal Clean Air Act) that emits at least 100 tpy, or any other facility that emits at least 250 tpy. Effective July 1, 2011, PSD will also apply to a new stationary source that emits more than 100,000 tpy of GHGs and more than 100 tpy of any individual GHG. Because the emissions of all PSD pollutants will be below 100 tpy, and the GHG emissions for the proposed project will be below the PSD major source threshold of 100,000 tpy, the proposed project is not subject to PSD review.

Nonattainment New Source Review

Nonattainment New Source Review jurisdiction has been delegated to the GBUAPCD for all pollutants and is discussed further under local requirement conformance below.

New Source Performance Standards

The boilers used at the proposed project will be subject to the following NSPS:

- Subpart Da: New Source Performance Standards for Electric Utility Steam Generating Units (auxiliary boilers)
- Subpart Db: New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units (startup boilers)
- Subpart Dc: New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units (nighttime preservation boilers)

The NSPS emissions limits are compared with the proposed permit limits in Table 5.1-40 below. Emissions from the boilers will be well below the NSPS limits.

TABLE 5.1-40
Comparison of Boiler Emission Rates with Applicable NSPS Standards

	NOx	SO_2	PM
Subpart Da Limit (Auxiliary Boilers)	0.20 lb/MMBtu	1.4 lb/MWh	0.015 lb/MMBtu
Subpart Db Limit (Startup Boilers)	0.20 lb/MMBtu	0.20 lb/MMBtu	none
Subpart Dc Limit (Nighttime Preservation Boilers)	None	none	none
Proposed Permit Level	0.011 lb/MMBtu	0.0021 lb/MMBtu	0.005 lb/MMBtu

The boilers are exempt from the continuous opacity and SOx monitoring requirements of the NSPS because they will burn solely natural gas fuel. The auxiliary boilers must continuously monitor NOx emissions (40 CFR 60.49a), but will use the NOx CEMS required under Part 75 to meet the NOx monitoring requirement. The startup boilers will use predictive emissions monitoring in lieu of continuous monitoring for NOx (40 CFR 48b(g)(2)).

- Subpart IIII: New Source Performance Standards for Stationary Compression Ignition Engines (emergency engines, including fire pump engines)

The power block emergency generators, rated at 2.5 MW, are subject to Nonroad Tier 2 emission standards;[21] the project will comply by purchasing Tier 2 engines. The common area emergency generator, rated at 250 kW, is subject to Nonroad Tier 3 standards; a Tier 3 –certified engine has been selected for this application. The fire pump engines proposed for the project are certified to Tier 3 nonroad standards, as required by the NSPS.

National Emission Standards for Hazardous Air Pollutants

This program establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established) from facilities in specific source categories. These standards are implemented at the local level with federal oversight. EPA has promulgated NESHAP for boilers at area sources (40 CFR 63 Subpart JJJJJJ) and compression ignition engines (RICE; 40 CFR 63 Subpart ZZZZ). However, the area source boiler NESHAP does not apply to natural-gas-fired units, while the RICE NESHAP requires only new emergency RICE to comply with the applicable NSPS. Therefore the NESHAP will impose no additional requirements on the facility.

Acid Rain Program

This program requires the monitoring and reporting of emissions of acidic compounds and their precursors from combustion power generation equipment. These requirements are implemented at the local level with federal oversight. GBUAPCD has received delegation authority to implement Title IV. The auxiliary boilers will be required to comply with the acid rain program requirements. The applicant will file an acid rain permit application in accordance with the deadlines in GBUAPCD Rule 217.

Title V Operating Permits Program

This program requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, Phase II acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. GBUAPCD has received delegation authority for this program. The project is subject to Title V requirements because it is a Phase II acid rain facility and will comply with the requirements of Title V by filing the required permit application in accordance with the deadlines in GBUAPCD Rule 217.

5.1.6.2 Consistency with State Requirements

As discussed in Section 5.1.2.2, state law established local air pollution control districts and air quality management districts with the principal responsibility for regulating emissions from stationary sources. The proposed project is under the local jurisdiction of the GBUAPCD; therefore, compliance with GBUAPCD regulations will assure compliance with state air quality requirements.

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[21] Because these are emergency engines, they are not required to meet standards that require “add-on” controls, such as diesel particulate filters or SCR.

The CO_2 emission rate of 0.132 MT/MWh would meet the EPS of 0.500 MT/MWh. However, as a solar power plant, the project is not designed or intended for base load generation. The EPS applies only to procurements that entail an annualized capacity factor in excess of 60 percent. With an expected operating capacity that is the equivalent of approximately 3,000 full-load hours per year, the project's annualized capacity factor will be less than 50 percent. Therefore, the SB 1368 limitation does not apply to this facility.

5.1.6.3 Consistency with Local Requirements

The GBUAPCD has been delegated responsibility for implementing local, state, and federal air quality regulations in the Great Basin Valleys Air Basin. HHSEGS is subject to GBUAPCD regulations that apply to new stationary sources, to the prohibitory regulations that specify emission standards for individual equipment categories, and to the requirements for evaluation of impacts from non-criteria pollutants. The following sections include the evaluation of facility compliance with applicable GBUAPCD requirements.

New Source Review Requirements

The GBUAPCD's NSR rule (Rule 209-A Standards for Authorities to Construct) establishes the criteria for siting new and modified emission sources; this rule is applicable to the proposed project. There are three basic requirements within the NSR rules. First, BACT requirements must be applied at any new facility with potential emissions above specified threshold quantities. Second, all potential emission increases of nonattainment pollutants or precursors from the proposed source above specified thresholds must be offset by real, quantifiable, surplus, permanent, and enforceable emission decreases in the form of emission reduction credits (ERCs). Third, an ambient air quality impact analysis must be conducted to confirm that the project does not cause or contribute to a violation of a national or California AAQS or jeopardize public health.

BACT

A comparison of potential emissions with the BACT thresholds in GBUAPCD Rule 209-A is presented in Table 5.1-41. GBUAPCD has indicated that exempt units and emergency units are not included in the determination of BACT requirements, so only total daily emissions from the auxiliary boilers and startup boilers are included here.[22] This table shows that the boilers are not required to use BACT for NOx, VOC, SO_2 or PM_{10}.

TABLE 5.1-41
Applicability of BACT Requirements Under NSR

Pollutant	BACT Threshold, lb/day	Facility Emissions, lb/day	BACT Required?
NOx	250	240	no
VOC	250	117	no
SO_2	250	47	no
PM_{10}	250	111	no

[22] The nighttime preservation boilers are exempt from permit requirements (Rule 201.F: natural-gas-fired steam generators that have a maximum heat input rate of less than 15 MMBtu/hr); the WSACs are also exempt from permit requirements (Rule 201.D.4: water cooling towers not used for evaporative cooling of process water).

Nevertheless, a detailed discussion regarding control technology options for these boilers is provided in Appendix 5.1C. A summary of the proposed controlled emission rates is provided in Table 5.1-42.

TABLE 5.1-42
Summary of Proposed Control Technologies

Pollutant	Control Technology	Concentration
NOx, boilers	ultra-low NOx burners	9 ppmc
CO	good combustion practices	25 to 50 ppmc
VOC	good combustion practices	10 to 12.6 ppmc
SO_2	natural gas fuel	—
PM_{10}/$PM_{2.5}$, boilers	natural gas fuel	—
PM_{10}/$PM_{2.5}$, WSACs	high-efficiency drift eliminators	0.0005% (drift rate)
GHGs	natural gas fuel supplementing solar generation	0.060 lb/MWh

Offsets

GBUAPCD Rule 209-A requires that projects with operational emissions above 250 pounds per day of NOx, VOC, PM_{10}, or SOx provide emission offsets by emission reductions from other sources. Based on emissions data presented in Table 5.1-41 above, daily emissions from the project will not exceed GBUAPCD's offset thresholds.

Air Quality Impact Analysis

Under the GBUAPCD new source review regulations (Rule 216), an air quality impact analysis must be performed to confirm that the emission increases for a project will not interfere with the attainment or maintenance of an applicable ambient air quality standard or cause additional violations of a standard anywhere the standard is already exceeded. The modeling results presented in Section 5.1.4.5 show that the proposed project will not interfere with the attainment or maintenance of the applicable air quality standards or cause additional violations of any standards.

New Source Review Requirements for Air Toxics

The GBUAPCD's Toxic Risk Assessment Policy describes the requirements and standards for assessing cancer risks from facilities that emit TACs. The rule requires a demonstration that the source will not exceed the applicable health risk thresholds. The project will comply with the requirements of this rule. An air toxics health risk assessment consistent with GBUAPCD requirements is provided in Section 5.9, Public Health.

New Source Performance Standards

The GBUAPCD's New Source Performance Standards (Regulation IX) incorporates the federal NSPS from 40 CFR Part 60. The applicability and requirements of and compliance with the New Source Performance Standards are discussed above under the federal regulations section.

Federal Programs and Permits

The federal Title IV acid rain program requirement and Title V operational permit requirements are in GBUAPCD's Rule 217. The applicability and requirements of and compliance with these programs and permits are discussed above under the federal regulations section.

Public Notification

Public notice under Rule 209-A.E (Power Plants) is required and the applicant expects the GBUAPCD Air Pollution Control Officer will provide this notice in a timely manner.

Permit Fees

The GBUAPCD requirements regarding permit fees are specified in Regulation III. This regulation establishes the filing and permit review fees for specific types of new sources, as well as annual renewal fees and penalty fees for existing sources. The project will pay the applicable fees in accordance with these requirements.

Prohibitions

The GBUAPCD prohibitions for specific types of sources and pollutants are addressed in Regulation IV. The prohibition rules that apply to the project are summarized below.

Rule 50 – Visible Emissions: This rule prohibits any source from discharging any emissions of any air contaminant that is darker in shade than that designated as Number 1 on the Ringelmann Chart for a period or periods aggregating more than 3 minutes in any period of 60 consecutive minutes. The project's use of natural gas would eliminate the possibility of dark visible emissions. Therefore, the project is expected to comply with this requirement.

Rule 51 – Nuisance: This rule prohibits the discharge from a facility of air contaminants that cause injury, detriment, nuisance, or annoyance to the public, or cause damage to business or property. The project would not emit odorous pollutants, and the screening level health risk assessment included in the Public Health Section demonstrates that the potential health risk from the emissions is less than significant.

Rule 52 – Particulate Matter Emission Standards: This rule prohibits the discharge from any source of particulate matter in excess of 0.10 grain per dry standard cubic foot (0.23 grams per dry standard cubic meter) of gas. The project will have particulate matter emissions less than 0.23 grams per dry standard cubic meter and will thus comply with this rule.

Rule 62 – Sulfur Content of Fuels: This rule prohibits any stationary source from using any gaseous fuel containing more than 10 grains of sulfur compounds per 100 cubic feet of dry gaseous fuel. The natural gas used for the project will have a maximum sulfur content of 0.75 (short term) grains per 100 cubic feet of dry gaseous fuel, well below the limit under this rule.

5.1.7 Mitigation Measures

5.1.7.1 Operational Emissions: Permitted Units

The project's emissions are below the levels that require BACT or offsets under GBUAPCD regulations. Although BACT is not required, emissions from the boilers and engines will be well controlled, as discussed in Appendix 5.1C. Modeling shows that the project will not result in any significant air quality impacts.

Table 5.1-45 compares the emissions from the project with the emissions that would occur if the energy provided by the project were provided by a new 500 MW natural-gas-fired combined cycle turbine project operating 3,000 hours per year, utilizing Best Available Control Technology (assumptions: heat rate of 7,000 Btu/kWh, 2 ppmv NOx, 3 lb PM_{10} per 100 MW, 2 ppmv CO, 1.4 ppmv VOC, 0.0006 lb/MMBtu SO_2).

TABLE 5.1-43
Comparison of Emissions Between HHSEGS and a Well-Controlled Gas Turbine

Emissions/Equipment	Pollutant				
	NOx	SO_2	CO	VOC	$PM_{10}/PM_{2.5}$
Maximum Annual Emissions, total tons per year					
HHSEGS	12.3	1.8	30.2	4.8	4.4
Combined-Cycle Gas Turbine Project	48	3.2	23.1	8.4	22

5.1.7.2 Construction Activities

Mitigation measures for construction period impacts are discussed in Appendix 5.1F.

5.1.7.3 Greenhouse Gas Emissions

Every megawatt-hour generated by the project will displace a megawatt-hour that would otherwise have been generated by a more traditional (i.e., fossil-fuel-fired) source of electricity. The project therefore is expected to result in a net reduction in emissions of GHGs.

As discussed above, the project's GHG impacts are not significant. GHG regulatory offset requirements will be addressed through CARB-approved measures, including the possible acquisition of allowances under a cap-and-trade program.

5.1.7.4 Mirror Cleaning and Other Maintenance Activities

Emissions from mirror cleaning activities were quantified in Section 5.1.4.3. To minimize exhaust emissions from the mirror washing and refueling vehicles, the project will use new model year vehicles that meet then-current California on-road vehicle emission standards or applicable USEPA /California off-road engine emission standards for the model year in effect when the vehicles are purchased. To minimize fugitive dust emissions from maintenance operations, including travel of mirror washing vehicles on unpaved roads, a dust control plan will be prepared that includes fugitive dust control measures such as use of soil stabilization techniques and limits on vehicle speed. Mitigation measures that will be included in the operational dust control plan include the following:

- Operations and wind erosion control techniques, such as windbreaks and chemical dust suppressants, and ongoing maintenance procedures that will be used on areas that could be disturbed by vehicles or wind anywhere within the project boundaries; and

- Limitations on vehicles speeds to not more than 10 mph on unpaved roadways that are not stabilized and up to 25 mph on stabilized unpaved roads as long as such speeds to not create visible dust emissions.

5.1.8 Involved Agencies and Agency Contacts

Each level of government (state, federal, and county/local air district) has adopted specific regulations that limit emissions from stationary combustion sources, several of which are applicable to this project. The air agencies having permitting authority for this project are shown in Table 5.1-44. The applicable federal LORS and compliance with these requirements are discussed in more detail in Sections 5.1.2.1 and 5.1.6.1.

TABLE 5.1-44
Agency Contacts for Air Quality

Issue	Agency	Contact
Permit issuance and oversight, enforcement	EPA Region 9	Gerardo Rios EPA Region 9 75 Hawthorne Street San Francisco, CA 94105 (415) 972-3974
Regulatory oversight	CARB	Mike Tollstrup Project Assessment Branch California Air Resources Board 1001 I Street Sacramento, CA 95812 (916) 323-8473
Permit issuance, enforcement	Great Basin Unified Air Pollution Control District	Duane Ono Deputy Air Pollution Control Officer GBUAPCD 157 Short Street Bishop, CA 93514 (760) 872-8211

5.1.9 Permits Required and Permit Schedule

Under Regulation II of its Rules and Regulations, GBUAPCD regulates the construction, alteration, replacement, and operation of new stationary emissions sources and modifications to existing sources. In addition, pursuant to its Rule 209-A.E Power Plants, GBUAPCD's Air Pollution Control Officer will conduct a DOC review upon receipt of the AFC for the project. This DOC for the project will be provided by GBUAPCD as part of the CEC review to confirm that the project will meet all of GBUAPCD's rules and regulations. A preliminary DOC (PDOC) is expected within approximately 180 days after GBUAPCD accepts the application as complete. The PDOC will be circulated for public comment, and a final DOC (FDOC) will be issued by the GBUAPCD after comment has been considered and addressed. Upon approval of the AFC by the CEC with conditions incorporating the requirements of the FDOC, the FDOC will confer upon the applicant all of the rights and privileges of an Authority to Construct (ATC). GBUAPCD will then assume responsibility for issuing and enforcing a Permit to Operate (PTO) for the project. This permitting process allows the GBUAPCD to adequately review new and modified air pollution sources to ensure compliance with all applicable prohibitory rules and to ensure that appropriate emission controls will be used. An ATC allows for the construction of the air pollution source and remains in effect until the PTO application is granted, denied, or canceled. Once the project has completed construction and commences operations, GBUAPCD will require verification that the project conforms to the ATC application and, following such verification, will issue a PTO. The PTO specifies conditions that the air pollution source must meet to comply with all air quality standards and regulations.

The GBUAPCD has also received delegation from EPA to administer the federal Title IV and Title V programs for sources in the Great Basin Valley Air Basin. HHSEGS will be exempt from many of the acid rain program requirements, but the project will be required to estimate SO_2 and CO_2 emissions from the project and to monitor NOx and O_2 emissions with a certified CEMS, and will submit an acid rain permit application 24 months prior to commencement of operation. The HHSEGS must also submit a Title V permit application within 12 months after commencement of plant operation pursuant to GBUAPCD Rule 217.

5.1.10 References

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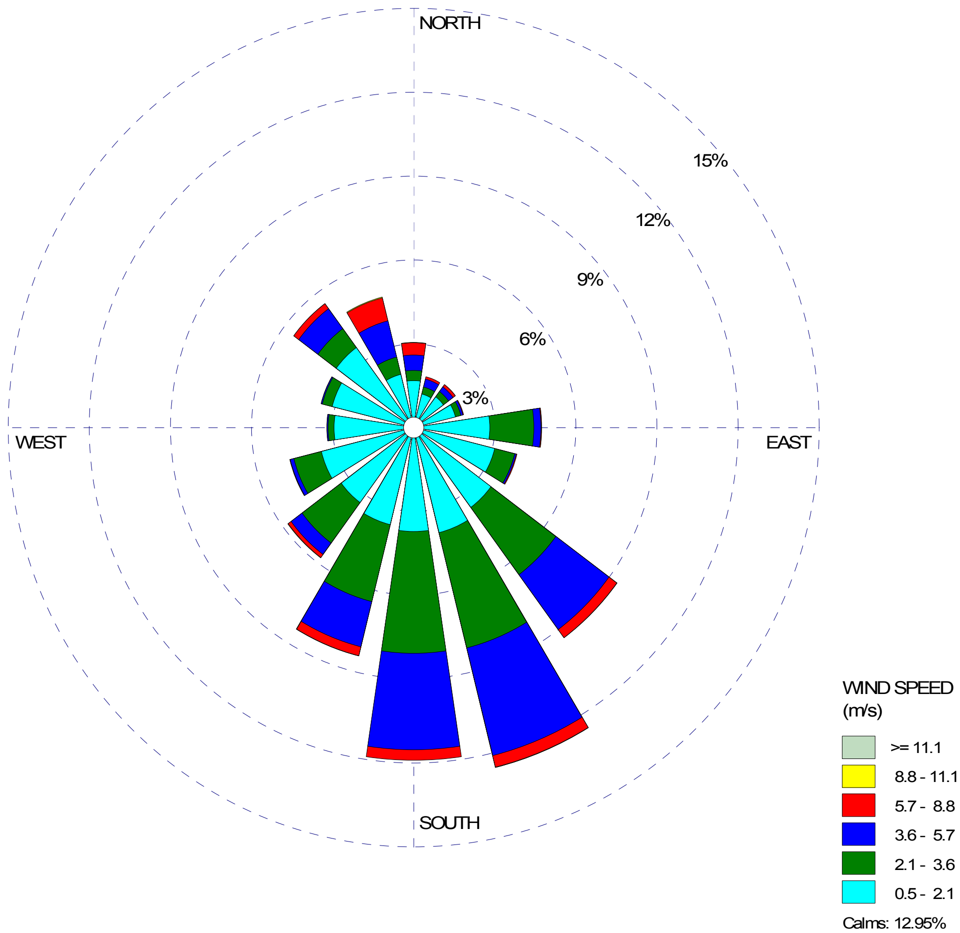
WIND ROSE PLOT:

Pahrump, NV, All five years, 2006~2010

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **Start Date: 1/1/2006 - 00:00** **End Date: 12/31/2010 - 15:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **12.95%**	TOTAL COUNT: **43754 hrs.**	
	AVG. WIND SPEED: **2.08 m/s**	DATE: **6/6/2011**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Source: Sierra Research, 2011.

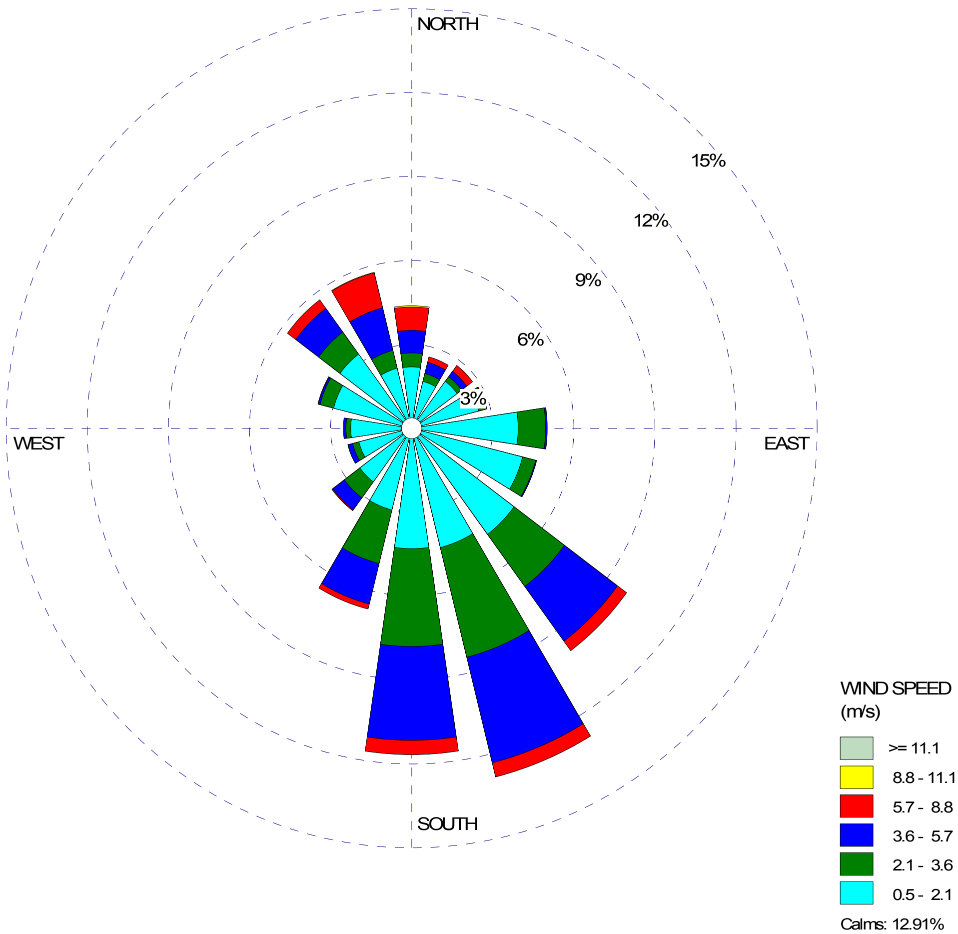
FIGURE 5.1-1
Composite Wind Rose for Pahrump, Nevada: Annual, 2006-2010
Hidden Hills Solar Electric Generating System

WIND ROSE PLOT:

Pahrump, NV, 1st Quarter, 2006~2010

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:

Start Date: 1/1/2006 - 00:00
End Date: 3/31/2010 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

12.91%

TOTAL COUNT:

10816 hrs.

AVG. WIND SPEED:

2.06 m/s

DATE:

6/6/2011

PROJECT NO.:

WRPLOT View - Lakes Environmental Software

FIGURE 5.1-2
Composite Wind Rose for Pahrump, Nevada: First Quarter, 2006-2010

Hidden Hills Solar Electric Generating System

Source: Sierra Research, 2011.

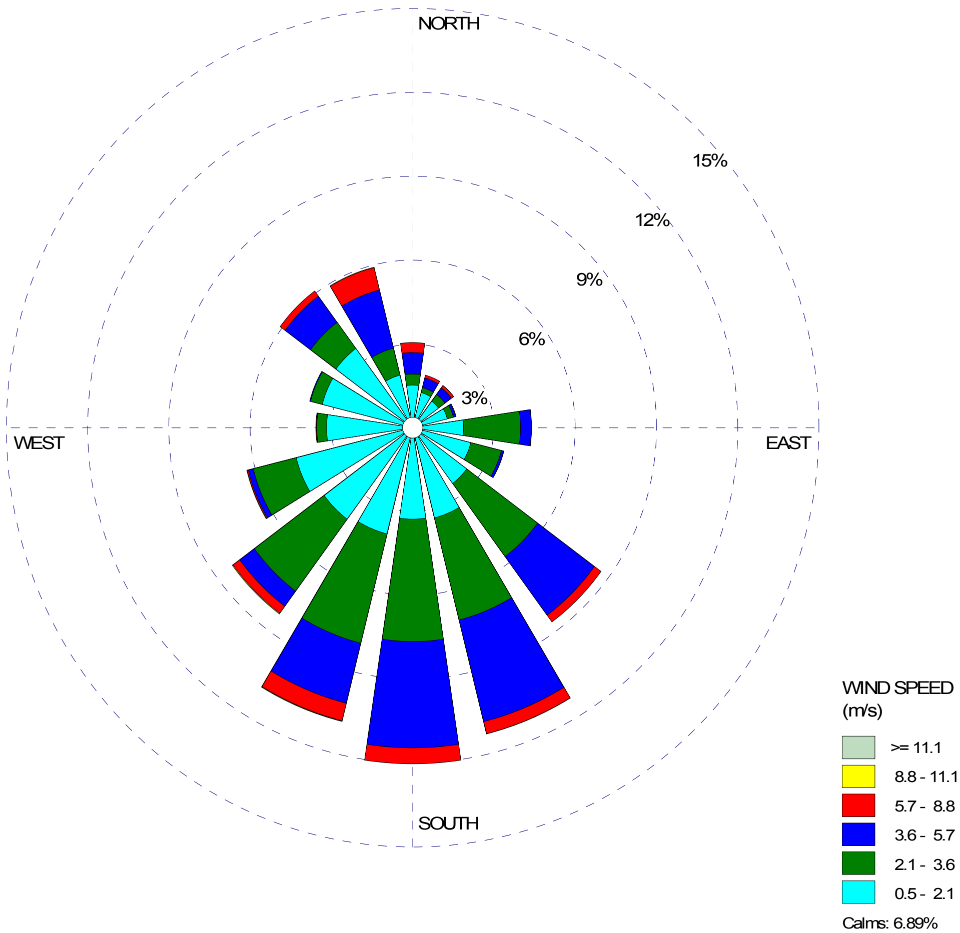
CH2MHILL

WIND ROSE PLOT:

Pahrump, NV, 2nd Quarter, 2006~2010

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:

Start Date: 4/1/2006 - 00:00
End Date: 6/30/2010 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

6.89%

TOTAL COUNT:

10904 hrs.

AVG. WIND SPEED:

2.39 m/s

DATE:

6/6/2011

PROJECT NO.:

WRPLOT View - Lakes Environmental Software

FIGURE 5.1-3
Composite Wind Rose for Pahrump, Nevada: Second Quarter, 2006-2010
Hidden Hills Solar Electric Generating System

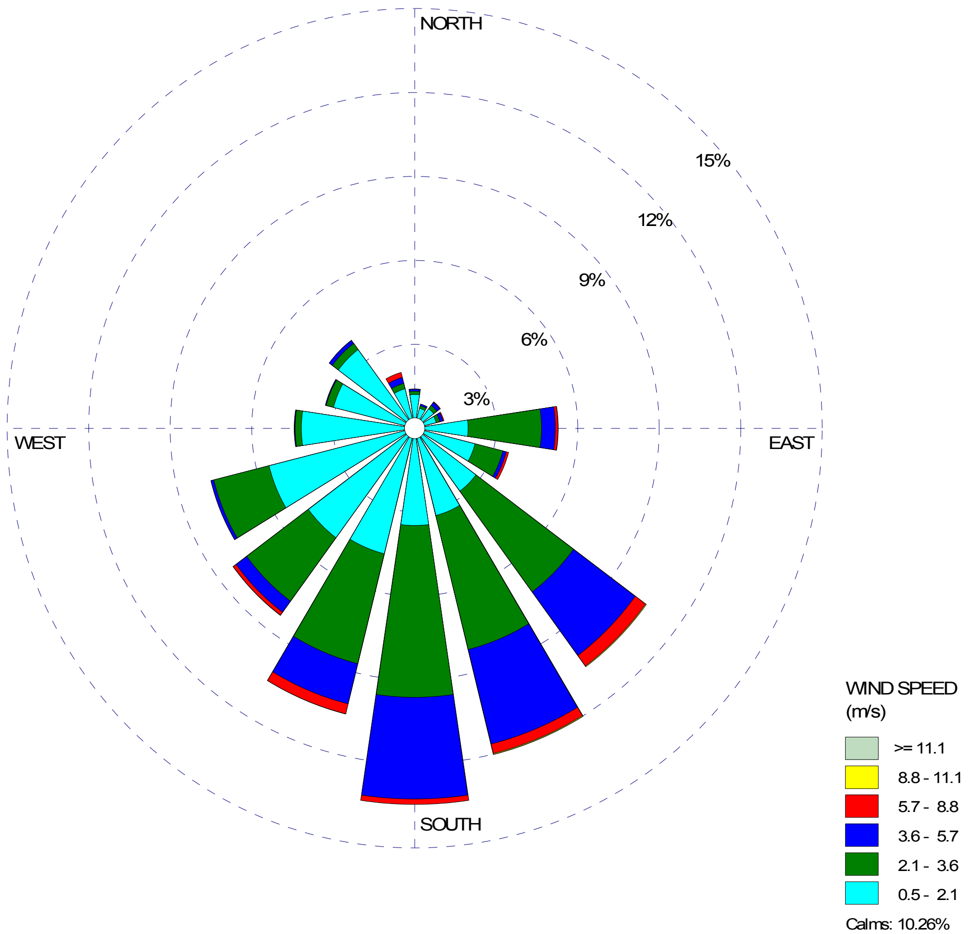
Source: Sierra Research, 2011.

WIND ROSE PLOT:

Pahrump, NV, 3rd Quarter, 2006~2010

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **Start Date: 7/1/2006 - 00:00** **End Date: 9/30/2010 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **10.26%**	TOTAL COUNT: **11027 hrs.**	
	AVG. WIND SPEED: **2.08 m/s**	DATE: **6/6/2011**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

FIGURE 5.1-4
Composite Wind Rose for Pahrump, Nevada: Third Quarter, 2006-2010
Hidden Hills Solar Electric Generating System

Source: Sierra Research, 2011.

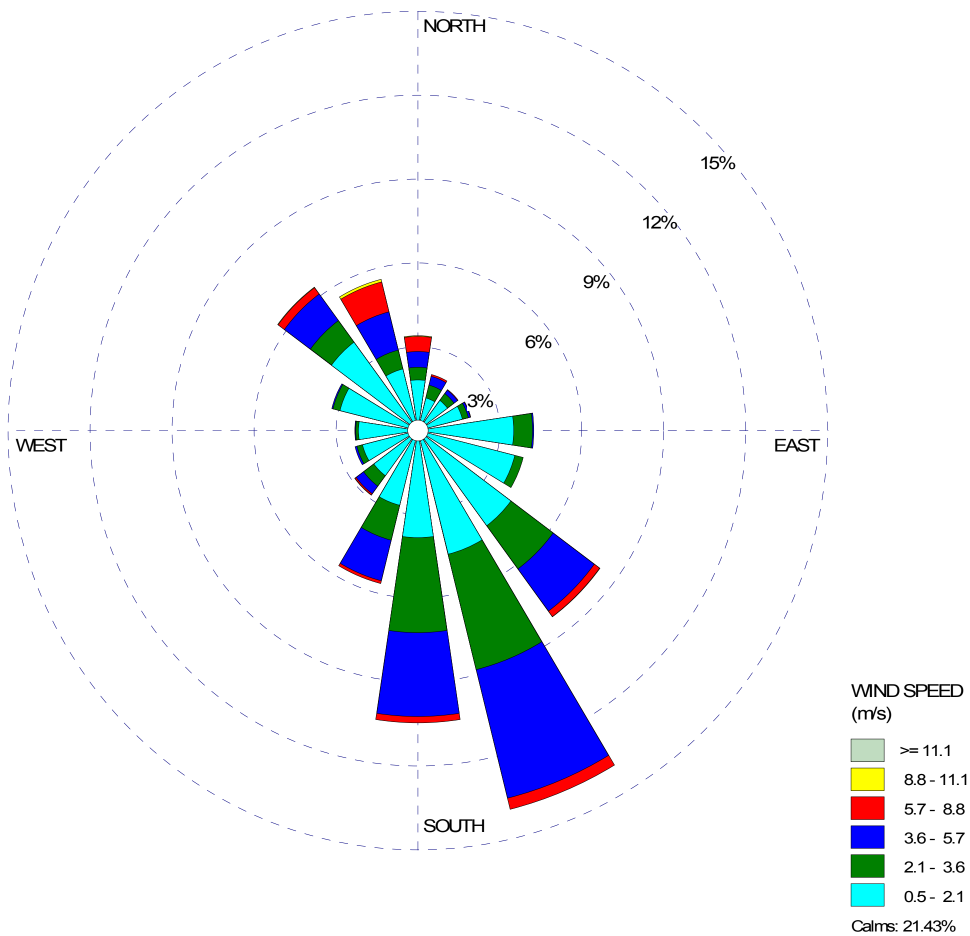
CH2MHILL

WIND ROSE PLOT:

Pahrump, NV, 4th Quarter, 2006~2010

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:

Start Date: 10/1/2006 - 00:00
End Date: 12/31/2010 - 15:00

COMPANY NAME:

MODELER:

CALM WINDS:

21.43%

TOTAL COUNT:

11007 hrs.

AVG. WIND SPEED:

1.77 m/s

DATE:

6/6/2011

PROJECT NO.:

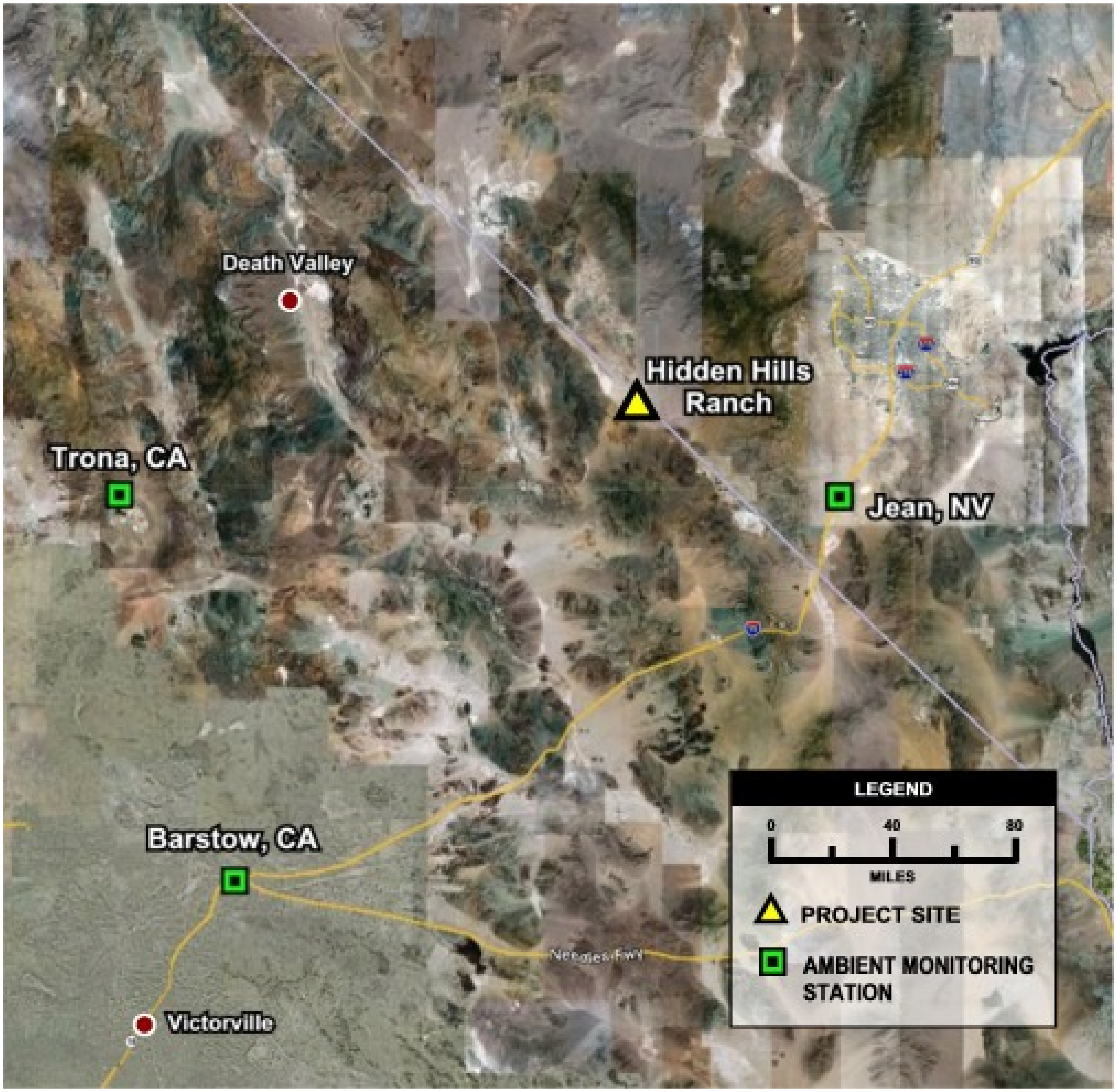
WRPLOT View - Lakes Environmental Software

FIGURE 5.1-5
Composite Wind Rose for Pahrump, Nevada: Fourth Quarter, 2006-2010

Hidden Hills Solar Electric Generating System

Source: Sierra Research, 2011.

CH2MHILL



Aerial image courtesy of Google™ Earth, 2011. Images ©2011 DigitalGlobe, USDA Farm Service Agency.

FIGURE 5.1-6
Locations of the Ambient Monitoring Stations
Hidden Hills Solar Electric Generating System