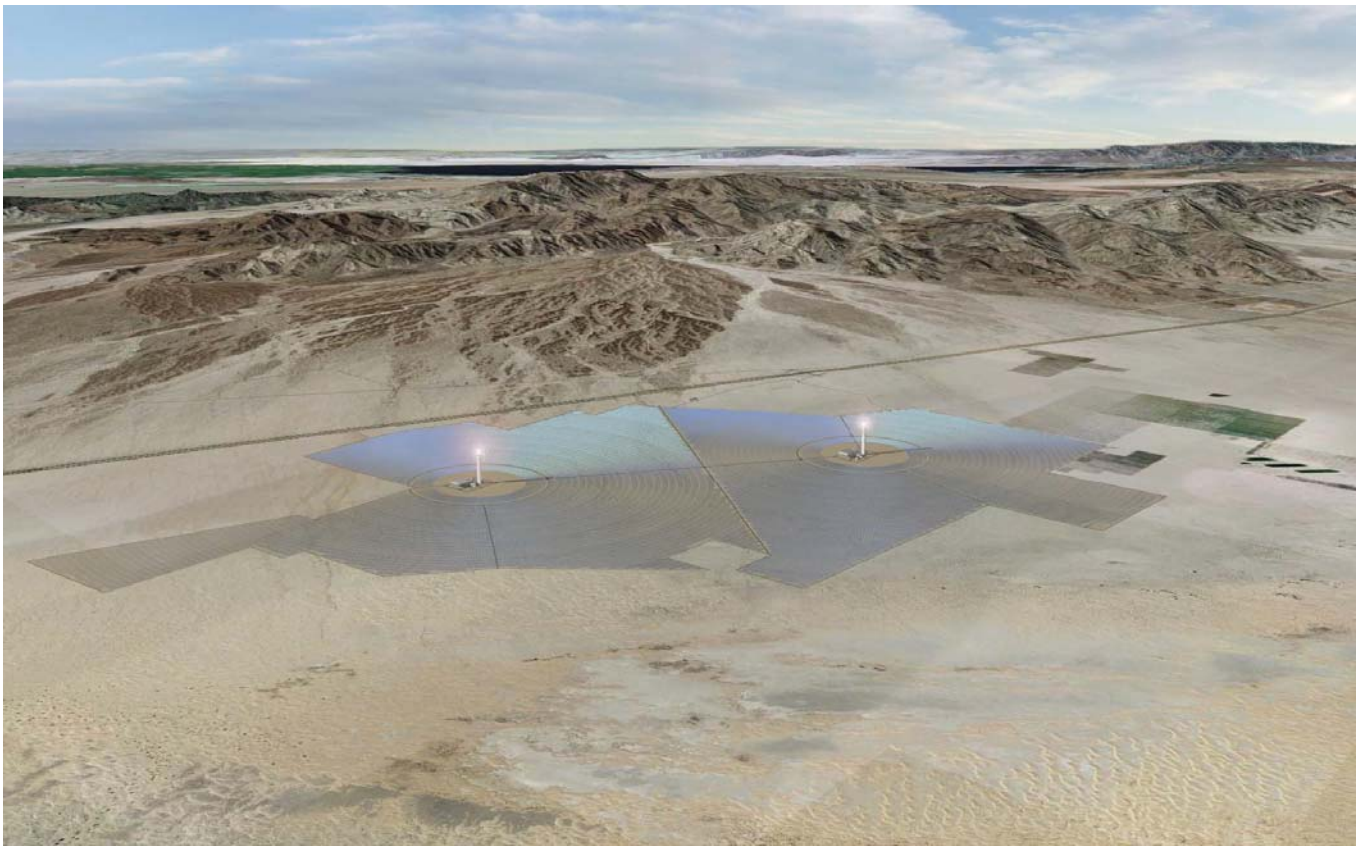
DOCKETED

Docket Number:	09-AFC-07C
Project Title:	Palen Solar Power Project - Compliance
TN #:	201097
Document Title:	Palen - Final Staff Assessment Part C
Description:	Final Staff Assessment - Part C
Filer:	Marci Errecart
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	11/1/2013 2:07:13 PM
Docketed Date:	11/1/2013

PALEN SOLAR ELECTRIC GENERATING SYSTEM

Final Staff Assessment for the Palen Solar Electric Generating System, Part C

Amendment to the Palen Solar Power Project



CALIFORNIA
ENERGY COMMISSION
Edmund G. Brown, Jr, Governor

November 2013
CEC-700-2013-003-FSA-PTC

DOCKET NUMBER 09-AFC-7C

CALIFORNIA
ENERGY COMMISSION
1516 Ninth Street
Sacramento, CA 95814

www.energy.ca.gov/sitingcases/palen

CHRISTINE STORA
Project Manager

CHRIS MARXEN
Compliance Office Manager

MATT LAYTON
Engineering Office Manager

ROGER E. JOHNSON
Deputy Director
Siting, Transmission and
Environmental Protection Division

ROBERT P. OGLESBY
Executive Director

AIR QUALITY

Testimony of Jacquelyn Leyva Record

SUMMARY OF CONCLUSIONS

Staff finds that with the adoption of the attached Conditions of Certification the proposed project would comply with all applicable laws, ordinances, regulations, and standards (LORS) and would not result in any significant air quality-related impacts. Staff also concludes that:

- The project would comply with applicable South Coast Air Quality Management District (SCAQMD or District) Rules and Regulations, including New Source Review (NSR) requirements.
- The project would not cause new violations of any NO_2, SO_2, or CO ambient air quality standards, and therefore, the project's direct NOx, SOx and CO emissions are not significant.
- Staff has analyzed the potential incremental greenhouse gas (GHG) emission impacts from the proposed project and concludes that they are not cumulatively considerable and thus do not represent a significant impact under the California Environmental Quality Act (CEQA). Refer to the Greenhouse Gas Appendix for details.

~~California Energy Commission staff (hereinafter referred to as "staff") finds that, with the adoption of the attached conditions of certification, the proposed Palen Solar Energy Generating System (PSEGS) project would comply with all applicable state and federal laws, ordinances, regulations, and standards and would not result in any significant California Environmental Quality Act (CEQA) air quality impacts. These conditions of certification meet the Energy Commission's responsibility to comply with the Warren-Alquist Act and the California Environmental Quality Act.~~

Staff ~~have~~ has also concluded that the proposed project would not have the potential to exceed Prevention of Significant Deterioration emission threshold levels during ~~direct source~~ operations. ~~and the facility is not considered a major stationary source with potential to cause adverse National Environmental Policy Act air quality impacts. This potential exceedance of a federal air quality emission threshold would be considered a direct, adverse impact under National Environmental Policy Act. This impact would be less than adverse with the proposed mitigation measures controlling fugitive dust emissions during construction.~~

The PSEGS would emit substantially lower greenhouse gas[1] emissions per megawatt-hour than fossil-fueled generation resources in California. PSEGS, as a renewable energy generation facility, ~~is determined by rule to~~ would comply with the Greenhouse Gas Emission Performance Standard requirements of SB 1368 (Chapter 11, Greenhouse Gases Emission Performance Standard, Article 1, Section 2903 [b][1]).

---

[1] Greenhouse gas (GHG) emissions are not criteria pollutants, but they affect global climate change. In that context, staff evaluates the GHG emissions from the proposed modified project (Appendix Air-1), presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

This air quality assessment includes information provided by the South Coast Air Quality Management District (SCAQMD) based upon the October 18, 2013, Preliminary Determination of Compliance (PDOC). As staff prepared this air quality assessment, corrections and typos to the PDOC were identified. Staff has provided these as informal comments to SCAQMD staff and has incorporated these corrections in this section. Some of the emission data shown in the analysis have been discussed with the SCAQMD and minor changes were agreed upon and incorporated herein. Staff may also provide formal written comments to SCAQMD. Additional edits may be needed once the Final Determination of Compliance (FDOC) is published. This air quality assessment will be updated as needed with a Supplemental Final Staff Assessment (FSA) once the Final Determination of Compliance (FDOC) is published.

Changes from the previously published staff assessment are shown with new text underlined and deleted text is shown as ~~strikethrough.~~

INTRODUCTION

On December 17, 2012, Palen Solar Holdings, LLC (PSH), filed a petition with the Energy Commission requesting to modify the Palen Solar Power Project (PSPP). The PSPP, as licensed on December 15, 2010, by the California Energy Commission (Energy Commission) (Order No. 10-1215-19, the Final Decision, 09-AFC-7), was a 500-megawatt (MW) solar thermal power-generating facility utilizing parabolic trough technology. The PSPP project encompassed approximately 4,366 acres located approximately 0.25 mile north of Interstate 10, approximately 10 miles east of Desert Center, and approximately halfway between the cities of Indio and Blythe, in Riverside County, California.

In the petition, PSH (or project owner) requested that the project name be changed from Palen Solar Power Project (PSPP) to Palen Solar Electric Generating System (PSEGS). In this document, the acronym PSPP refers to the approved project and the acronym PSEGS refers to the proposed modified project. Please see the section titled **PROPOSED MODIFIED PROJECT** for more detail about proposed modifications.

The PSEGS proposal includes replacing the parabolic trough solar collection system and associated Heat Transfer Fluid (HTF) with solar tower technology. The solar tower technology would create steam to run an electricity generator by using a field of heliostats—elevated mirrors, each approximately 12 feet tall, mounted on pylons and guided by a sun-tracking system—to focus the sun’s rays on a solar receiver steam generator (SRSG) on top of a 750-foot solar tower located near the center of each solar field.

This analysis evaluates the expected air quality impacts from the emissions of criteria air pollutants from both the construction and operation of the PSEGS (or proposed modified project). Criteria air pollutants are defined as air contaminants for which the state and/or federal governments, per the California Clean Air Act and the Federal Clean Air Act, have established ambient air quality standards to protect public health.

The criteria pollutants analyzed within this section are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), and particulate matter (PM). Lead is not analyzed as a criteria pollutant, but lead and other toxic air pollutant emissions impacts are analyzed in the Public Health Section of this ~~Preliminary~~ Final Staff Assessment (~~PSA~~ FSA). Two subsets of particulate matter are inhalable particulate matter (less than 10 microns in diameter, or PM10) and fine particulate matter (less than 2.5 microns in diameter, or PM2.5). Nitrogen oxides (NOx, consisting primarily of nitric oxide [NO] and NO_2) and volatile organic compounds (VOC) emissions readily react in the atmosphere as precursors to ozone and, to a lesser extent, particulate matter. Sulfur oxides (SOx) readily react in the atmosphere to form particulate matter and are major contributors to acid rain. Global climate change and greenhouse gas (GHG) emissions from the proposed modified project are discussed in **APPENDIX AIR-1** and analyzed in the context of cumulative impacts.

In carrying out this assessment, staff evaluated the following major issues:

- whether PSEGS is likely to conform with applicable federal, state, and SCAQMD air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- whether PSEGS is likely to cause new violations of ambient air quality standards or contribute substantially to existing violations of those standards (Title 20, California Code of Regulations, section 1743); and
- whether mitigation measures proposed for PSEGS in the conditions of certification are adequate to lessen potential impacts under CEQA, to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).

METHODOLOGY AND THRESHOLDS FOR DETERMINING ENVIRONMENTAL CONSEQUENCES

A significant impact is defined under CEQA as “a substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project” (Cal. Code Regs., tit. 14 [hereinafter CEQA Guidelines] Section 15382). Questions used in evaluating significance of air quality impacts are based on Appendix G of the CEQA Guidelines (CCR 2006). The specific approach used by staff in determining CEQA significance is discussed in more detail below.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

The federal, state, and local laws and policies applicable to the control of criteria pollutant emissions and mitigation of air quality impacts for the PSEGS are summarized in **Air Quality Table 1**. Staff’s analysis examines the proposed modified project’s compliance with these requirements.

Air Quality Table 1
Laws, Ordinances, Regulations, and Standards

Applicable LORS	Description
Federal	
40 Code of Federal Regulations (CFR) Part 52	Nonattainment New Source Review (NSR) requires a permit and requires Best Available Control Technology (BACT) and Offsets. Permitting and enforcement delegated to South Coast Air Quality Management District (SCAQMD). Prevention of Significant Deterioration (PSD) requires major sources or major modifications to major sources to obtain permits for attainment pollutants. The PSEGS is a new source that does not have a rule listed emission source thus the PSD trigger levels are 250 tons per year for NOx, VOC, SO_2, PM2.5 and CO.
40 CFR Part 60	New Source Performance Standards (NSPS), Subpart Db, Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generation Units. Establishes recordkeeping and reporting requirements for natural gas ~~(including propane)~~ fired steam generating units. Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Establishes emission standards for compressions ignition internal combustion engines, including emergency generator and fire water pump engines.
40 CFR Part 93 General Conformity	Requires determination of conformity with State Implementation Plan for projects requiring federal approvals if project annual emissions are above specified levels.
40 CFR, Part 63	National Emissions Standards for Hazardous Air Pollutants (NESHAPS)
State	
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with California Air Resource Board (ARB) approved Clean Air Plans.
HSC Section 41700	Restricts emissions that would cause nuisance or injury.
California Code of Regulations (CCR) Section 93115	Airborne Toxics Control Measure for Stationary Compression Ignition Engines. Limits the types of fuels allowed, established maximum emission rates, establishes recordkeeping requirements on stationary compression ignition engines, including emergency generator and fire water pump engines.
Title13 ,CCR, section 2423	Exhaust Emission Standards and Test Procedures: Heavy-Duty Off-Road Diesel Cycle Engines. Limits the tier levels of emissions from heavy-duty off-road diesel cycle engines, including emergency backup generators and emergency firewater pump engines.
Local (South Coast Air Quality Management District)	
Rules 201, 203, and 212 – Permit to Construct, Permit to Operate, and Standards for Approving Permits and Issuing Public Notice	Establishes the requirements to obtain a Permit to Construct and Permit to Operate for emission sources.
Rule 401 – Visible Emissions	Limits visible emissions.

Applicable LORS	Description
Rule 402 – Nuisance	Prohibits the discharge of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to the public or which endanger the comfort, response, health or safety of the public or which cause injury or damage to business or property.
Rule 403 – Fugitive Dust	Limits fugitive emissions from certain bulk storage, earthmoving, construction and demolition, and manmade conditions that may cause wind erosion.
Rule 404 – Particulate Matter Concentration	The rule limits particulate matter (PM) emissions. PM emission limits included in the rule are functions of the exhaust flow rate from the regulated device.
Rule 409 – Combustion Contaminants	Limits combustion contaminant discharge into the atmosphere from fuel burning equipment to 0.1 grain or less per cubic foot of gas calculated to 12% of carbon dioxide (CO_2) at standard conditions.
Rule 429 – NOx Exemptions for Startup/Shutdown	Provides NOx emission exemptions for boiler subject to Rule 1146 for periods of startup and shutdown.
Rule 431.1 – Sulfur Compounds of Gaseous Fuels	Limits discharge into the atmosphere of sulfur compounds from the burning of gaseous fuels.
Rule 431.2 – Sulfur Compounds of Liquid Fuels	Limits discharge into the atmosphere of sulfur compounds from the burning of liquid fuels.
Rule 463 – Organic Liquids Storage	Sets standards for storage of organic liquids with a true vapor pressure of 0.5 pounds per square inch or greater.
Rule 474–Fuel Burning Equipment–Oxides of Nitrogen	Limits the discharge of NO_2 to the atmosphere to the concentrations specified in the rule.
Regulation IX – New Source Performance Standard	Incorporates the Federal NSPS (Title 40 CFR 60) rules by reference.
Rule 1110.2 – Emissions From Gaseous and Liquid-Fueled Internal Combustion Engines	The purpose of this rule is to reduce NOx, VOCs, and CO from engines.
Rule 1121 – NOx Control from NG Fired Water Heaters	Limits NOx emissions from natural gas fired residential type water heaters and would apply to the administration building.
Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators and Process Heaters	This rule limits NOx emissions from boilers, steam generators, and process heaters.
Rule 1166 – VOC Emissions from Decontamination of Soil	Establishes requirements to control VOC emissions from handling of VOC-contaminated soil.
Regulation XIII – New Source Review	Establishes the pre-construction review requirements, including Best Available Control Technology and emission offset requirements for new, modified or relocated facilities to ensure that these facilities do not interfere with progress in attainment of the national ambient air quality standards.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Energy Commission staff assesses four kinds of primary and secondary[2] impacts: construction, operation, closure and decommissioning, and cumulative. Construction impacts result from the onsite and offsite emissions occurring during site preparation and construction of the proposed modified project. Operation impacts result from the emissions of the proposed modified project during operation, which includes all of the onsite auxiliary equipment emissions (boilers, emergency engines, etc.), the onsite maintenance vehicle emissions, and the offsite employee and material delivery trip emissions. Closure and decommissioning impacts occur from the onsite and offsite emissions that would result from dismantling the facility and restoring the site. Cumulative impacts analysis assesses the impacts that result from the proposed modified project's incremental effect viewed over time, together with other closely related past, present, and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed modified project. (Pub. Resources Code § 21083; Cal. Code Regs., tit. 14, §§ 15064(h), 15065(c), 15130, and 15355.)

METHODOLOGY AND THRESHOLD FOR DETERMINING CEQA SIGNIFICANCE

Energy Commission staff evaluate potential impacts per Appendix G of the CEQA Guidelines (CCR 2006). A CEQA significant adverse impact is determined to occur if potentially significant CEQA impacts cannot be mitigated through the adoption of Conditions of Certification. Specifically, staff uses health-based ambient air quality standards (AAQS) established by the California Air Resources Board (ARB) and the U.S. Environmental Protection Agency (U.S. EPA), as a basis for determining whether a project's emissions will cause a significant adverse impact under CEQA. The standards are set at levels that include a margin of safety and are designed to adequately protect the health of all members of the public, including those most sensitive to adverse air quality impacts such as the aged, people with existing illnesses, children, and infants. Staff evaluates the potential for significant adverse air quality impacts by assessing whether the project's emissions of criteria pollutants (NO_2, VOC, PM10/PM2.5 and SO_2) and their precursors could create a new AAQS exceedance (emission concentrations above the standard), or substantially contribute to an existing AAQS exceedance.

Staff evaluates both direct and cumulative impacts. Staff will find that a project or activity will create a direct adverse impact when it causes an exceedance of an AAQS. Staff will find that a project's effects are cumulatively considerable when the project emissions in conjunction with ambient background, or in conjunction with reasonably foreseeable future projects, substantially contribute to ongoing exceedances of an AAQS. Factors considered in determining whether contributions to ongoing exceedances are substantial include:

1. the duration of the activity causing adverse air quality impacts;

---

[2] Primary impacts potentially result from facility emissions of NOx, SOx, CO and PM10/2.5. Secondary impacts result from air contaminants that are not directly emitted by the facility but formed through reactions in the atmosphere that result in ozone, and sulfate and nitrate PM10/PM2.5.

2. the magnitude of the project emissions, and their contribution to the air basin's emission inventory and future emission budgets established to maintain or attain compliance with AAQS;
3. the location of the project site, i.e., whether it is located in an area with generally good air quality where non-attainment of any ambient air quality standard is primarily or solely due to pollutant transport from other air basins;
4. the meteorological conditions and timing of the project impacts, i.e., do the project's maximum modeled pollutant impacts occur when ambient concentrations are high (such as during high wind periods, or seasonally);
5. the modeling methods, and how refined or conservative the impact analysis modeling methods and assumptions were and how that may affect the determined adverse impacts;
6. the project site location and nearest receptor locations; and whether the identified adverse impacts would also occur at the maximum impacted receptor location; and
7. potential for future cumulative impacts; and whether appropriate mitigation is being recommended to address the potential for impacts associated with likely future projects.

PROPOSED MODIFIED PROJECT

The PSEGS proposal includes replacing the already approved parabolic trough solar collection system and associated HTF with solar tower technology. The PSEGS would be comprised of two adjacent solar fields and associated facilities with a total combined nominal output of approximately 500 MW. PSH proposes to develop the PSEGS in two operational units, each consisting of one solar field, one tower, and a power block capable of producing approximately 250 MW of electricity. The solar tower technology would create steam to run an electricity generator by using a field of heliostats—elevated mirrors, each approximately 12 feet tall, mounted on pylons and guided by a sun-tracking system—to focus the sun's rays on a solar receiver steam generator (SRSG) on top of a 750-foot solar tower located near the center of each solar field. Access to the site would use the same primary access road as the PSPP. The modified project would interconnect to the regional electrical transmission grid at Southern California Edison's (SCE's) Red Bluff Substation as proposed for PSPP; the Red Bluff Substation is currently under construction.

Two natural gas-fired ~~auxiliary~~ boilers are proposed for each power block, for a total of four for the project. ~~A startup~~ One auxiliary boiler would be used during the morning startup cycle to assist the power generation equipment in coming up to operating temperature more quickly and for augmenting the solar operation when solar energy diminishes or during transient cloudy conditions. Each solar field also includes ~~a~~ one small night preservation boiler also fueled with natural gas to provide steam to the gland systems of the steam turbine and boiler feedwater pump turbine to prevent air ingress overnight and during ~~other~~ shutdown periods when steam is not available from the SRSG. This boiler would also provide pegging steam to the generator during these shutdowns (**Project Description Figures 4**, **5,** and **6**).

The two units would share common facilities, including an on-site switchyard, a single-circuit, 230-kV generation tie-line, and a common area containing an administration building, warehouse, evaporation ponds, maintenance complex, and a meter/valve station for incoming natural gas service to the site. Other on-site facilities would include access and maintenance roads (either dirt, gravel, or paved), perimeter fencing, tortoise fencing, and other ancillary security facilities.

The PSEGS footprint is smaller by 572 acres than the original footprint of the PSPP. While the PSPP included the use of a private parcel (of approximately 40 acres) located in the northeast portion of the site, the PSEGS would not include any solar facility development within this private parcel. The PSPP also had Energy Commission approval to develop the private parcels (approximately 240 acres) located in the southeastern portion of the site, if the project owner acquired the parcels. The PSEGS owner would not acquire or develop these private parcels.

The primary modifications to the PSPP are as follows:

- Two 250-MW power-generating units, each consisting of a dedicated field of approximately 85,000 heliostats, a 750-foot solar tower and receiver, and a power block;
- An approximately 15-acre common facilities area located in the southwestern corner of the site, with an administrative/warehouse building and two 2-acre evaporation ponds (reduced from four 2-acre evaporation ponds for the PSPP);
- An approximately 203-acre temporary construction laydown area located in the southwestern portion of the site immediately north of the common facilities area;~~.~~
- Re-routing of the generation tie-line near the western end of the route and around the under-construction Red Bluff Substation; the purpose of this re-routing is to align the PSEGS generation tie-line route so that it is immediately adjacent to the NextEra Desert Sunlight generation tie-line to minimize crossings over Interstate 10 and to ensure easy entry into the Red Bluff Substation nearest the PSEGS breaker position;
- Re-routing of the redundant telecommunication line along the generation tie-line route;
- Natural gas delivery from a new extension of the existing Southern California Gas (SoCal Gas) distribution system to the project boundary rather than using propane as proposed for PSPP;
- Reduction of the project footprint from 4,366 acres to 3,794 acres;
- Reduction of the amount of grading by 4.3 million cubic yards because the heliostat technology does not require an entirely flat surface;
- Reduction of the amount of water used by 99 acre-feet per year (AFY); and
- An increase in annual NOx emissions from the use of the auxiliary boilers. ~~This will be evaluated in the FSA when the operational portion of the analysis is done.~~

SETTING AND EXISTING CONDITIONS

Climate and Meteorology

The Mojave Desert Air Basin (MDAB) is an assemblage of mountain ranges interspersed with long broad valleys that often contain dry lakes. Many of the lower mountains which dot the vast terrain rise from 1,000 to 4,000 feet above the valley floor. Prevailing winds in the MDAB are out of the west and southwest. These prevailing winds are due to the proximity of the MDAB to coastal and central regions and the blocking nature of the Sierra Nevada mountains to the north; air masses pushed onshore in southern California by differential heating are channeled through the MDAB (MDAQMD 2009). MDAB has a typical desert climate characterized by low precipitation, hot summers, mild winters, low humidity, and strong temperature inversions. Total rainfall in Desert Center (approximately 10 miles southwest of the project site) averages just less than 4 inches per year with about 50 percent of the total rainfall occurring during the December through March winter rainy season, and about 30 percent occurring during the August/September summer monsoon season (WC 2009). On average August is the wettest month.

The highest monthly average high temperature is 104°F in July and the lowest average monthly low temperature is 45°F in January and December (WC 2009). The project owner provided a wind rose from Blythe Airport Automated Surface Observing System (ASOS) for the years 2002 to 2006. This wind data indicates the highest annual wind direction frequencies are from the south through the southwest. Due to the topography of the particular site, staff would expect a more westerly wind direction. Calm conditions occur approximately 16 percent of the time, with the annual average wind speed approximately 3.66 meters per second (m/s) or 8.19 miles per hour (mph).

Sensitive Receptors

The general population includes many sensitive subgroups that may be at greater risk from exposure to emitted pollutants. These sensitive subgroups include the very young, the elderly, and those with existing illnesses. In addition, the location of the population in the area surrounding a project site may have a large bearing on health risk. There are no sensitive receptors identified within a 3-mile buffer zone around the project site. The nearest sensitive receptor (Eagle Mountain Elementary School) is approximately 10 miles west of the boundary of the proposed modified project in the City of Blythe. There are agricultural fields and residences located northwest of the project site[3].

Existing Ambient Air Quality

The Federal Clean Air Act and the California Clean Air Act both require the establishment of standards for ambient concentrations of air pollutants, called ambient air quality standards (AAQS). The state of California AAQS (CAAQS), established by the ~~California Air Resources Board~~ ARB, are typically lower (more protective) than the federal AAQS, which are established by the U.S.EPA. The state and federal air quality standards are listed in **Air Quality Table 2**. The averaging times for the various air quality standards, the times over which they are measured, range from one hour to an

[3] According to Socioeconomics Figure 1 as of April 1, 2010 there were no people counted as part of the Decennial Census.

annual average. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant in a cubic meter of air (mg/m^3 or μg/m^3, respectively).

Since the March 2010 Staff Assessment for PSPP, the implementation of new ~~Ambient Air Quality Standards (~~AAQS~~)~~ has led to changes in the categorization of air quality in the PSEGS project area. A new 1-hour nitrogen dioxide (NO_2) National Ambient Air Quality Standard (NAAQS) became effective on April 12, 2010. ~~Besides~~ In addition, a new 1-hour SO_2 NAAQS was established and the existing 24-hour and annual primary NAAQS were revoked on June 2, 2010.

In general, an area is designated as attainment if the concentration of a particular air contaminant does not exceed the standard. Likewise, an area is designated as non-attainment for an air contaminant if that contaminant standard is violated. In circumstances where there is not enough ambient data available to support designation as either attainment or non-attainment, the area can be designated as unclassified. The unclassified area is treated the same as an attainment area for regulatory purposes. An area could be attainment for one air contaminant while non-attainment for another, or attainment for the federal standard and non-attainment for the state standard for the same air contaminant.

The project site is located in the MDAB within the SCAQMD portion of Riverside County. This area is designated as non-attainment for the state ozone and PM10 standards and attainment or unclassified for all federal criteria pollutant ambient air quality standards and the state CO, NO~~x~~2, SO~~x~~2, and PM2.5 standards. **Air Quality Table 3** summarizes the project site area's attainment status for various applicable state and federal standards.

Ambient air quality monitoring data for ozone, PM10, PM2.5, CO, NO_2, and SO_2, compared to most restrictive applicable standards for the years between 2008 through 2012 at the most representative monitoring stations for each pollutant are shown in **Air Quality Table 4** and the 1-hour and 8-hour ozone, and 24-hour PM10 and PM2.5 data for the years 2004 through 2012 (PM10 and PM2.5) are shown in **Air Quality Figure 1**. Ozone data are from the Blythe–445 West Murphy Street monitoring station which is approximately 35 miles east of the project site, PM10, PM2.5, NO_2 and CO data are from the Palm Springs-Fire Station monitoring station located approximately 75 miles west of the project site, and SO_2 data are from the Victorville–14306 Park Avenue monitoring station which is located approximately 135 miles west northwest of the project site. These station locations were deemed to be the closest stations with data representative of the project site for the various averaging times. These data are from areas that are more urbanized than the project's location and are likely to exceed values at the project location. The highlighted data represents the recommended background values listed in **Air Quality Table 5**.

Air Quality Table 2
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.075 ppm[a] (147 µg/m^3)	0.070 ppm (137 µg/m^3)
	1 Hour	—	0.09 ppm (180 µg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9.0 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual	0.053 ppm (100 µg/m^3)	0.03 ppm (57 µg/m^3)
	1 Hour	0.100 ~~ppm[c]~~ ppm[b]	0.18 ppm (339 µg/m^3)
Sulfur Dioxide (SO_2)	Annual	0.030 ppm (80 µg/m^3)	—
	24 Hour	0.14 ppm (365 µg/m^3)	0.04 ppm (105 µg/m^3)
	3 Hour	0.5 ppm (1300 µg/m^3)	—
	1 Hour	0.075 ppm (196 µg/m^3)[c]	0.25 ppm (655 µg/m^3)
Particulate Matter (PM10)	Annual	—	20 µg/m^3
	24 Hour	150 µg/m^3	50 µg/m^3
Fine Particulate Matter (PM2.5)	Annual	~~15~~ 12 µg/m^3	12 µg/m^3
	24 Hour	35 µg/m^3	—
Sulfates (SO_4)	24 Hour	—	25 µg/m^3
Lead	30 Day Average	—	1.5 µg/m^3
	Calendar Quarter	1.5 µg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42 µg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.01 ppm (26 µg/m^3)
Visibility Reducing Particulates	8 Hour	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.

Notes:a - On April 30, 2012, U.S. EPA issued final area designations and classifications for the 2008 (0.075 ppm) 8-hour ozone standard. ~~The 2008 standard is shown above, but as of September 16, 2009 this standard is being reconsidered. The 1997 8-hour standard is 0.08 ppm.~~

b - On October 19, 2012, U.S. EPA published a proposed rule in the Federal Register revising ambient NO2 monitoring requirements. Currently, near-roadway NO2 monitors are required to be deployed by January 1, 2012; the proposal would establish a phased deployment, with deployment required between January 1, 2014 and January 1, 2017.

c - On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard, effective August 23, 2010, which is based on the 3-year average of the annual 99th percentile of 1-hour daily maximum concentrations. The existing 0.030 ppm annual and 0.14 ppm 24-hour SO_2 NAAQS however must continue to be used until one year following U.S. EPA initial designations of the new 1-hour SO_2 NAAQS.

~~c - On April 12, 1010, the U. S. EPA adopted a new short-term NO2 standard, based upon a 3-yer average of the 98th percentile of daily maximum 1-hour values.~~

Source: ARB 2013a (www.arb.ca.gov/desig/feddesig.htm) ~~ARB 2013a~~

Air Quality Table 3
Federal and State Attainment Status – Project Site Area within Riverside County

Pollutant	Attainment Status[1]	
	Federal	**State**
Ozone	Attainment[2]	Moderate Nonattainment
CO	Attainment	Attainment
NO_2	Unclassifiable /Attainment[3]	Attainment
SO_2	Attainment	Attainment
PM10	Attainment[2]	Nonattainment
PM2.5	Attainment	Attainment

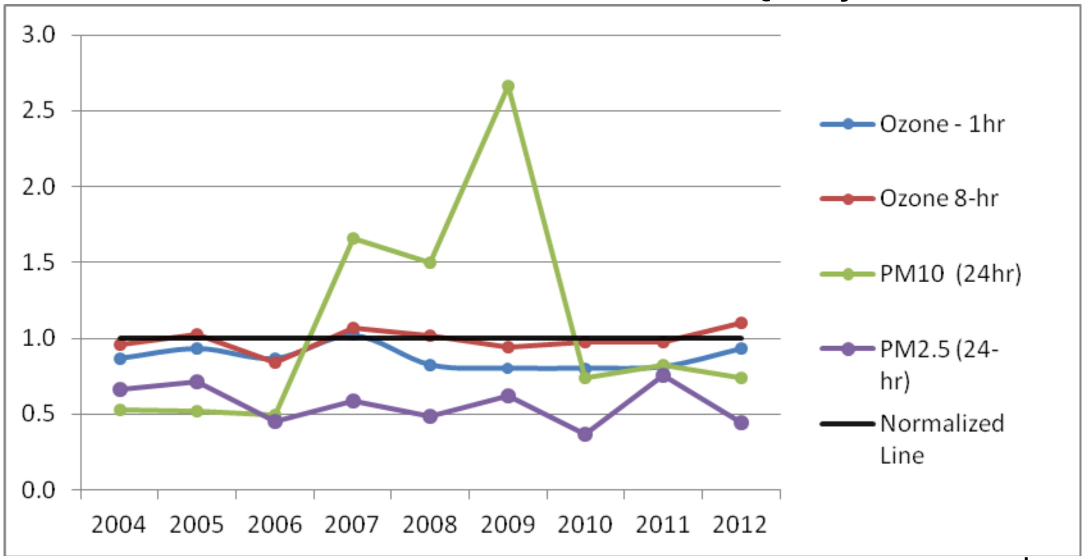
Notes:
1 - Attainment = Attainment or Unclassified, where Unclassified is treated the same as Attainment for regulatory purposes.
2 - Attainment status for the site area only, not the entire MDAB.
3 – On February 17, 2012, the U.S. Environmental Protection Agency designated all of the United States as “unclassifiable/ attainment” for the short-term federal NO_2 standard, effective February 29, 2012.
Source: ARB 2013b, U.S.EPA 2013a.

Air Quality Table 4
Criteria Pollutant Summary
Maximum Ambient Concentrations (ppm or $\mu g/m^3$)

Pollutant	Monitoring Station	Averaging Period	Unit s	2008	2009	2010	2011	2012	Limiting AAQS[c]
Ozone	Blythe–445 West Murphy Street	1 hour	ppm	0.074	0.072	0.072	0.073	0.084	0.09
Ozone	Blythe–445	8 hours	ppm	0.071	0.066	0.068	0.068	0.077	0.07
PM10 [a,b]	Palm Springs-Fire Station	24 hours	μg/m3	75	**133.0**	37	41	37	50
PM10 [a,b]	Palm	Annual	μg/m3	**23.2**	*20.4	18.3	18.1	16.1	20
PM2.5 [a]	Palm	24 hours	μg/m3	17.1	21.8	12.8	**26.3**	15.5	35
PM2.5 [a]	Palm	Annual	μg/m3	**7.2**	*6.6	5.9	6.0	6.5	12
CO	Palm	1 hour	ppm	1.3	2.3	1.6	**3.0**	0.90	20
CO	Palm	8 hours	ppm	0.54	**0.67**	0.50	0.60	0.50	9.0
NO_2	Palm	1 hour	ppm	**0.049**	0.048	0.046	0.045	0.045	0.18
NO_2	Palm	Federal 1	ppm	**0.045**	0.039	0.039	0.039	0.039	0.10
NO_2	Palm	Annual	ppm	**0.009**	0.008	0.009	0.008	*0.007	0.03
SO_2	Victorville–14306 Park Avenue	1 hour (3yr 99th percentile)	ppm	0.005	0.006	**0.011**	0.007	0.005	0.075
SO_2	Victorville–	3 hour	ppm	0.006	**0.006**	0.006	0.005	0.005	0.5
SO_2	Victorville–	24 hours	ppm	0.002	0.005	**0.007**	0.007	0.003	0.04
SO_2	Victorville–	Annual	ppm	**0.001**	0.000	0.000	0.001	*0.001	0.03

Notes:
[a] - Exceptional PM concentration events, such as those caused by wind storms are not shown where excluded by U.S.EPA; however, some exceptional events may still be included in the data presented.
[b] - The PM10 data source is in the Coachella Valley that is classified as a serious PM10 nonattainment area.
[c] - The limiting AAQS is the most stringent of the CAAQS or NAAQS for that pollutant and averaging period.
* means there was insufficient data available to determine the value.
Bold values were used as staff’s recommended background values in **AQ Table 5**.
Source: ARB 2013c, U.S.EPA 2013b, SCAQMD 2013.

Air Quality Figure 1
2004-2012 Historical Ozone and PM Air Quality Data



Blythe and Palm Springs Monitoring Stations, Riverside County [a, b, c]

Notes: a - The highest measured ambient concentrations of various criteria air contaminants were divided by their applicable standard and provided as a graphical point. Any point on the chart that is greater than one means that the measured concentrations of such air contaminant exceed the standard, and any point that is less than one means that the respective standard is not exceeded for that year. For example the 24-hour PM10 concentration in 2008 is 75 µg/m^3/50 µg/m^3 standard = 1.5.
b - Ozone data are from Blythe–445 West Murphy Street monitoring station and the PM data are from the Palm Springs station.
c - All PM data are from Palm Springs monitoring station.
Source: ARB 2009c, U.S.EPA 2013b, SCAQMD 2013.

Ozone (O_3)

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between directly emitted nitrogen oxides (NOx) and hydrocarbons (Volatile Organic Compounds [VOC]) in the presence of sunlight to form ozone. Pollutant transport from the South Coast Air Basin (Los Angeles Area) is one source of the pollution experienced in the eastern Riverside County portion of the MDAB (SCAQMD 2007, p. 1-2).

As **Air Quality Table 4** and **Air Quality Figure 1** indicate, the 1-hour and 8-hour ozone concentrations measured at the eastern border of Riverside County have been very close to the standard and very slowly decreasing over time, although there is an upward trend between 2011 and 2012. The collected air quality data (not shown) indicate that the ozone violations occurred primarily during the sunny and hot periods typical during May through September.

Nitrogen Dioxide (NO_2)

The entire air basin is classified as attainment or unclassifiable for the state and federal 1-hour NO_2 standard and the annual federal NO_2 standard.

Approximately 90 percent of the ambient NOx emitted from combustion sources is nitric oxide (NO), while the balance is NO_2. NO is oxidized in the atmosphere to NO_2, but some level of photochemical activity is needed for this conversion. The highest concentrations of NO_2 typically occur during the fall. The winter atmospheric conditions can trap emissions near the ground level, but lacking substantial photochemical activity (sun light), NO_2 levels are relatively low. In the summer the conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions disperse pollutants, preventing the accumulation of NO_2. The NO_2 concentrations in the project area are well below the state and federal ambient air quality standards.

Carbon Monoxide (CO)

The area is classified as attainment for the state and federal 1-hour and 8-hour CO standards. The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground level. These conditions occur frequently in the wintertime late in the afternoon, persist during the night and may extend one or two hours after sunrise. The project area, in comparison with major urban areas, only has ~~a lack of substantial~~ mobile source emissions on Interstate 10, but emissions decrease rapidly with distance from the highway. Monitoring data from ~~and based on~~ the Palm Springs-Fire Station monitoring site data are considered to be representative of the project site and the project site ~~the local~~ CO concentrations are expected to be well below the state and federal ambient air quality standards.

Particulate Matter (PM10) and Fine Particulate Matter (PM2.5)

PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere.

The area is non-attainment for the state PM10 standards. **Air Quality Table 4** and **Air Quality Figure 1** shows recent PM10/PM2.5 concentrations from a station in the adjacent Coachella Valley portion of the Salton Sea Air Basin (SSAB), which are assumed to provide a conservative basis for the project site area. The figure shows fluctuating concentrations patterns, and shows clear exceedances of the state 24-hour PM10 standard. It should be noted that exceedance does not necessarily mean violation or nonattainment, as exceptional events do occur and some of those events, which do not count as violations, may be included in the data.

Fine particulate matter, or PM2.5, is derived mainly from either the combustion of materials, or from precursor gases (SOx, NOx, and VOC) through complex reactions in the atmosphere. PM2.5 consists mostly of sulfates, nitrates, ammonium, elemental carbon and a small portion of organic and inorganic compounds.

Portions of the MDAB are classified as non attainment for the federal PM10 standards and the state and federal PM2.5 standards; however, the project site is located in an unclassified or attainment portion of the MDAB for these standards. This divergence in the PM10 and PM2.5 concentration levels and attainment status indicate that a substantial fraction of the ambient particulate matter levels are most likely due to localized fugitive dust sources, such as vehicle travel on unpaved roads, agricultural operations, or wind-blown dust.[4]

---

[4] Fugitive dust, unlike combustion source particulate and secondary particulate, is composed of a much higher fraction of larger particles than smaller particles, so the PM2.5 fraction of fugitive dust is much smaller than the PM10 fraction. Therefore, when PM10 ambient concentrations are significantly higher than PM2.5 ambient concentrations this tends to indicate that a large proportion of the PM10 are from fugitive dust emission sources, rather than from combustion particulate or secondary particulate emission sources.

Sulfur Dioxide (SO_2)

The entire air basin is classified as attainment for the state and federal SO_2 standards.

Sulfur dioxide is typically emitted as a result of the combustion of a fuel containing sulfur. Sources of SO_2 emissions within the MDAB come from a wide variety of fuels: gaseous, liquid and solid; however, the total SO_2 emissions within the eastern MDAB are limited due to the limited number of major stationary sources and California's and U.S. EPA's substantial reduction in motor vehicle fuel sulfur content. The project area's SO_2 concentrations are well below the state and federal ambient air quality standards.

Summary

In summary, staff recommends the background ambient air concentrations in **Air Quality Table 5** for use in the modeling and impacts analysis. The recommended background concentrations are based on the maximum criteria pollutant concentrations from the past three years of available data collected at the most representative monitoring stations surrounding the project site.

Where possible, staff prefers that the recommended background concentration measurements come from nearby monitoring stations with similar characteristics. For this proposed modified project, the Blythe monitoring station (ozone), at approximately 35 miles east of the project site, is the closest monitoring station. The Palm Springs monitoring station (PM10, PM2.5, NO_2, and CO) is located approximately 75 miles west of the project site. The Victorville monitoring station (SO_2) is located approximately 135 miles west northwest of the project site. In general, the Palm Springs and Victorville monitoring stations are considered to provide conservative estimates of the worst case background concentrations due to their proximity to the South Coast Air Basin (Metropolitan Los Angeles). Monitoring stations located in Imperial County were not selected or considered as representative due to the predominant air flow patterns and due to air pollution from Mexico that creates a significant local influence for the worst-case pollutant concentration readings within Imperial County.

The background concentrations for PM10 are well above the most restrictive existing ambient air quality standards, while the background concentrations for the other pollutants are all below the most restrictive existing ambient air quality standards.

The pollutant modeling analysis was limited to the pollutants listed in **Air Quality Table 5**; therefore, recommended background concentrations were not determined for the other criteria pollutants (ozone, lead, visibility, etc.).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff provided a number of data requests regarding the construction and operations emission estimates and air dispersion modeling analysis (CEC 2013c), which the project owner responded to by providing revised emissions estimates (Palen 2013c) and substantially revised and more robust dispersion modeling analysis ~~(Solar Millennium 2010a)~~. Staff has reviewed the revised emission estimates and air dispersion modeling analysis[5] and finds them to be reasonable considering the level of emissions mitigation stipulated to by the project owner.

Air Quality Table 5
Staff Recommended Background Concentrations (μg/m³)

Pollutant	Averaging Time	Recommended Background	Limiting AAQS[b]	Percent of Standard
NO_2	1 hour	~~92~~ 124.3[c]	339	~~27~~ 37%
	Federal 1 hour (98th percentile)	~~84.6~~ 97.8 [c]	188	~~46~~ 52%
	Annual	~~17~~ 22.6	57	~~30~~ 39%
CO	1 hour	3,450	23,000	15%
	8 hour	744	10,000	7%
PM10	24 hour	133	50	266%
	Annual	23.2	20	116%
PM2.5	24 hour [a]	26.3	35	75%
	Annual	7.2	12	60%
SO_2	1 hour	28.7	196	15%
	3 hour	15.6	1,300	1%
	24 hour	18.4	105	18%
	Annual	2.9	80	4%

Source: ARB 2013c, U.S.EPA 2013b and Energy Commission Staff Analysis
Notes:
[a] PM2.5 24-hour data shown in **Air Quality Table 4** are 98th percentile values which is the basis of the ambient air quality standard and the basis for determination of the recommended background concentration.
[b] The limiting AAQS is the most stringent of the CAAQS or NAAQS for that pollutant and averaging period.
[c.] Updated to reflect PDOC.

Project Description

In each plant, one Rankine-cycle steam turbine would receive steam from the SRSG to generate electricity. The solar field and power generation equipment would start each morning after sunrise and would shut down (unless augmented by the auxiliary boiler) when solar insulation drops below the level required to keep the turbine on-line. Each plant would have two natural gas-fired ~~auxiliary~~ boilers. One larger 249 million British thermal units per hour (mmBtu/hr) boiler will be used during the morning start-up cycle to assist the power generation equipment in coming up to operating temperature more quickly and for augmenting the solar operation when solar energy diminishes or during transient cloudy conditions. The other smaller 10.5 mmBtu/hr night time preservation boiler would be used to maintain a minimum temperature of the water during the evening hours.

Each plant would use an air-cooled condenser (ACC) for the main steam cycle. A wet surface air cooler (WSAC) would be used for auxiliary equipment cooling. Raw water would be drawn daily from on-site wells located in each power block and in the common area adjacent to the administration building. Groundwater would be treated in on-site treatment systems and would be used for mirror washing, WSAC makeup, and process water makeup. Each power block would be connected via underground electrical cables

[5] This includes a review of the emission source inputs, including the type of source (point, volume, area) and the variables used to describe each source (emissions, height, location, temperature, etc. as appropriate).

to the on-site switchyard in the northern area of the site. Each power block would also have a gas meter.~~ing set.~~ Permanent parking areas would be provided at each power block for operations and maintenance personnel.

PSEGS would be a concentrated solar thermal electric generating facility with two adjacent (Unit #1 and Unit #2), independent, and similar solar plants of 250 megawatt (MW) nominal capacity each for a total nominal capacity of 500 MW. The PSEGS would be located in the Southern California inland desert, approximately 10 miles east of the small community of Desert Center, in eastern Riverside County, California. PSEGS facilities would occupy approximately 3,794 acres of public lands owned by the Federal government for which a right-of-way (ROW) lease is being obtained by the project owner from the Bureau of Land Management (BLM).

Units #1 and #2 would be developed in phases with construction scheduled to begin in early 2014 and continue through the second quarter of 2016. Commercial operation of Unit #1 is expected to begin in mid-2015, with commercial operation of Unit #2 ~~following~~ by the end of 2016.

~~The main operation area (solar field and power block) of Units #1 and #2 would occupy about 1,790 acres each. The two plants would share a main office building, a main warehouse / maintenance building and a parking lot, all located to the south of the solar fields. The two units would also share a storage tank for reverse osmosis (RO) concentrate (located in Unit #1) and a central internal switchyard located north of the solar fields. The main access road into the site would be located southwest of Unit #2.~~

~~The generation tie-line would be re-routed near the western end of the route and around the newly constructed Red Bluff Substation; the purpose of this re-routing is to align the PSEGS generation tie-line route so that it is immediately adjacent to the NextEra Desert Sunlight generation tie-line to minimize crossings over Interstate 10 and to ensure easy entry into the Red Bluff Substation nearest the PSEGS breaker position.~~

Project Emissions

Project Construction

The total duration of project construction for PSEGS is estimated to be approximately 33 months, and would include construction of the two solar fields and two power blocks.

The total site related acreage is ~3,794 acres, (i.e., the area inside the fence-line). Only 337.2 acres would actually be graded or have extensive earthwork. The maximum acreage disturbed on any one day during construction (earthwork phase) would be approximately 10 percent of the total, or approximately 34 acres. The maximum acreage to be disturbed during power block and heliostat installation would be 211 acres, with these disturbance activities related to vehicle movements and heliostat foundation work. The maximum acreage disturbed on any one day during power block and heliostat installation would be 26 acres. Although the site is essentially flat, the site would require minimum grading and leveling prior to construction of the power blocks, support systems, solar array field, and site buildings. Site preparation includes finish grading, excavation of footings and foundations, and backfilling operations. After site preparation is finished, the construction of the foundations and structures is expected to begin. Once the foundations and structures are finished, installation and assembly of the mechanical and electrical equipment are scheduled to commence[6].

Combustion emissions would result from the off-road construction equipment, including diesel construction equipment used for site grading, excavation, and construction of onsite structures, and water and soil binder spray trucks used to control construction dust emissions; and off-road construction equipment used at the onsite batch plant. Fuel combustion emissions also would result from exhaust from on-road construction vehicles, including heavy duty diesel trucks used to deliver materials, other diesel trucks used during construction, and worker personal vehicles and pickup trucks used to transport workers to and from and around the construction site. Fugitive dust emissions would result from site grading/excavation activities, installation of a temporary 12 kV construction power transmission and the new project power transmission lines, completion of onsite wells and water pipelines, construction of power plant facilities, roads, and substations, the use of an onsite batch plant, and vehicle travel on paved and unpaved roads.

The project owner's mitigated maximum daily and annual construction emission estimates for the entire proposed modified project are provided below in **Air Quality Tables 6** and **7**. To determine the potential worst-case daily construction impacts, exhaust and dust emission rates have been evaluated for each source of emissions. Worst-case daily fugitive dust emissions are expected to occur during the first months of construction when site preparation occurs (Palen 2013c). The worst-case daily combustion exhaust emissions are expected to occur during the middle of the construction schedule during the installation of the major mechanical equipment and as shown in **Air Quality Table 6**. Annual emissions are based on the average equipment mix and use rates during the construction period. Daily emissions are derived from the annual values using the estimated construction time frame and as shown in **Air Quality Table 7**.

[6] Palen 2013c Appendix 4.1E

Air Quality Table 6
PSEGS Construction - Maximum Daily Emissions (lbs/day)

	NOx	VOC	CO	PM10	PM2.5	SOx
Onsite Construction Emissions						
Main Power Block (entire project)						
Off-road Equipment Exhaust	760.8	97.1	396	37.7	37.7	1.0
On-road Support Vehicles	0.17	0.14	1.63	0.026	0.026	0.00025
Fugitive Dust from Paved Roads	--	--	--	1.04	0.2	--
Fugitive Dust from Unpaved Roads	--	--	--	6.95	0.69	--
Fugitive Dust from Constr. Activities	--	--	--	21.7	4.65	--
Fugitive Dust from Batch Plant Emissions	--	--	--	2.09	0.21	--
Subtotal - Power Block Onsite Emissions	**761.0**	**97.2**	**397.6**	**69.5**	**43.5**	**1.0**
Power Block On-road Delivery/Hauling (offsite)	19.9	1.55	7.62	0.93	0.93	0.04
Fugitive Dust from Access Road Construction (offsite)	--	--	--	0.27	0.06	--
Worker Travel (offsite)	21.9	21.0	244.9	9.32	9.32	0.45
Fugitive Dust from Paved Roads (offsite)	--	--	--	7.4	1.25	--
Fugitive Dust from Unpaved Roads and track-out (offsite)	--	--	--	0.29	0.05	--

Source: Palen 2013c, Table 4.1E-1 and 2
Note: Some ~~Emissions that were not added may not be~~ are not additive due to occurring at different times during the construction schedule; all emissions include fugitive dust as appropriate.

Air Quality Table 7
PSEGS Construction - Maximum Annual Emissions (tons/period)

	NOx	VOC	CO	PM10	PM2.5	SOx
Construction Emissions						
Main Power Block (entire project)						
Off-road Equipment Exhaust	263.6	33.64	137.2	13.07	13.07	0.36
On-road Support Vehicles	0.057	0.047	0.563	0.009	0.009	0.001
Fugitive Dust from Paved Roads	--	--	--	0.34	0.06	--
Fugitive Dust from Unpaved Roads	--	--	--	2.07	0.21	--
Fugitive Dust from Constr. Activities	--	--	--	5.02	1.08	--
Fugitive Dust from Batch Plant Emissions	--	--	--	0.31	0.03	--
Subtotal - Power Block Onsite Emissions	**263.7**	**33.7**	**137.8**	**20.8**	**14.5**	**0.36**
Power Block On-road Delivery/Hauling (offsite)	6.9	0.54	2.64	0.323	0.323	0.013
Fugitive Dust from Access Road Construction (offsite)	--	--	--	0.27	0.06	--
Worker Travel (offsite)	7.59	7.28	84.9	1.4	1.4	0.155
Fugitive Dust from Paved Roads (offsite)	--	--	--	7.4	1.25	--
Fugitive Dust from Unpaved Roads and track-out (offsite)	--	--	--	0.29	0.05	--

Source: Palen 2013c, Table 4.1E-1 and 2
Note: Some Emissions ~~that were not added may not be~~ are not additive due to occurring at different times during the construction schedule; all emissions include fugitive dust as appropriate.

Initial Commissioning

Initial commissioning refers to a period of approximately 40 hours total, prior to beginning commercial operation when the equipment undergoes initial tuning and performance tests. Staff analyzed and has prepared Conditions of Certification that address the potential greater short-term emissions compared to normal operation emissions during this period.

Project Operation

The PSEGS facility would be a nominal 500 Megawatt (MW) solar electrical generating facility, consisting of two (2) 250 MW (gross) power towers and two centralized power blocks. The direct air pollutant emissions from power generation are negligible; however, there are auxiliary equipment and maintenance activities necessary to operate and maintain the facility.

The following are the stationary and mobile emission source operating assumptions that were used to develop the operation emissions estimates for the PSEGS:

Stationary Emission Sources

PSEGS would consist of two power plant units at the facility, each of which consists of the following equipment and emission estimate bases:

- One 249-MMBtu/hr auxiliary boiler, per power block, fired on natural gas. Daily emissions based on 1.7 hrs/day at 17.5 percent (low) load and 3.5 hours per day at variable high loads (25-100 percent), and a half hour for startup load each day. Annual emissions are based on 2,200 hr/year with 1446 hours at high load (25-100 percent), with 580 hours at 17.5 percent low load, and 174 hours of startup hours. Each boiler would be equipped with low-NOx burners and selective catalytic reduction (SCR) to limit NOx emissions to 5 parts per million by volume (ppmv), and a CO catalyst to reduce CO concentrations to 25 ppmv;

- One 10.5 MMBtu/hr nighttime preservation boiler, per power block, fired on natural gas. Daily emissions based on 14 hrs/day of normal operation (annual average) at full load during the night, and 1 hour during startup based on 4,830 hr/year at full load. Boilers will be equipped with ultra-low-NOx 9 ppmv burners and CO concentration limit of 25 ppmv;

- One 617 hp (460 kW) diesel-fired emergency fire water pump engine; Tier 3 Certification; engine emissions are based on 4.2 hours per month testing, not to exceed 50 hours per year, and will be limited to an annual maximum of 200 hr/yr maintenance, readiness testing, and emergency use. The engine would be limited to 30 min/test in any one hour (CEQA). Note the 200 hr/yr limit is inclusive of the allotted 50 hr/yr for maintenance and testing;

- One 3,633 hp (2500 kW) diesel-fired emergency generator engine; Tier 2 Certification; engine emissions are based on 4.2 hours per month testing, not to exceed 50 hours per year, and will be limited to an annual maximum of 200 hr/yr emergency use. The engine would be limited to 30 min/test in any one hour (CEQA). Note the 200 hr/yr limit is inclusive of the allotted 50 hr/yr for maintenance and testing; and

- One wet-surface air condenser unit; Circulation rate of 4,000 gallons per minute, 1500 milligrams per liter Total Dissolved Solids (TDS), drift eliminator with drift losses of less than or equal to 0.0005 percent, maximum run time of 12 hr/day and 4,000 hr/year.

Additional equipment would be installed and operated, which is common to both power blocks, in the common area:

- One 617 hp (460 kW) diesel-fired emergency fire water pump engine; testing one hour test per week, not to exceed 50 hours per year. Tier 3 Certification; and

- One 398 hp (250 kW) diesel-fired emergency generator engine; testing one hour test per week, not to exceed 50 hours per year. Tier 3 Certification.

Mobile Emissions Sources

Mirror washing activities will be up to 365 days per year, approximately 20 hours per day. The number of vehicles onsite will be approximately 26 dedicated to mirror washing activities.

The PSEGS onsite stationary and onsite and offsite mobile source emissions, totaled for *both* power blocks, are estimated and summarized in **Air Quality Tables 8** and **9**. Maximum Daily emissions are based on a 30 day average in **Air Quality Table 8**.

Air Quality Table 8
PSEGS Operations - Maximum Daily Emissions (lbs/day)

	NOx	**VOC**	**CO**	**PM10**	**PM2.5**	**SOx**
Onsite Operation Emissions	-	-	-	-	-	-
Auxiliary Boilers[a]	42.16	11.56	96.72	14.28	14.28	5.66
Night Time Preservation Boilers	3.38	1.22	5.70	2.20	2.20	0.62
Emergency Fire Pump Engines[b]	1.47	0.06	0.28	0.05	0.05	0.003
Emergency Generators[b]	8.53	0.59	2.26	0.21	0.21	0.01
Cooling Towers	---	---	---	0.36	0.36	--
Onsite Maintenance Vehicles[c]	8.83	2.58	5.92	0.37	0.37	1.86
Onsite Maintenance Vehicles Fugitives[c]	--	--	--	118.3	18.7	--
Subtotal of Onsite Emissions	64.37	16.01	110.88	135.41	35.81	8.16
Offsite Emissions[d]	-	-	-	-	-	-
Delivery Vehicles	1.74	0.18	1.17	0.085	0.084	0.004
Employee Vehicles	3.68	3.53	41.10	0.68	0.68	0.08
Subtotal of Offsite Emissions[e]	5.42	3.71	42.27	0.77	0.76	0.084
Total Maximum Daily Emissions	69.79	19.72	153.15	136.2	36.6	8.24
Approved PSPP Emission						
Approved Onsite Emissions	**73.63**	**64.04**	**72.31**	**322.92**	**78.61**	**10.56**
Percent in Onsite Emissions between Proposed and Approved projects	-12%	-75%	+53%	-58%	-54%	-22%

Source: SCAQMD 2013c Facility Emissions Summaries tables and staff estimate for employee vehicles.
a includes both boilers worse case of high boost mode, low mode, and a startup/shutdown per day.
b includes the common area equipment as well as both power plants.
c includes the mirror washing machines (MWMs), (light duty trucks) LDTs, and Water Trucks.
d Appendix 4.1A Table 4.1A-11
e SCAQMD emission estimates are different due to the onsite maintenance vehicles emissions included in staffs subtotal of onsite emissions.

Air Quality Table 9
PSEGS Operations - Maximum Annual Emissions (tons/yr)

	NOx	VOC	CO	PM10	PM2.5	SOx
Onsite Operation Emissions	-	-	-	-	-	-
Auxiliary Boilers[a]	5.65	1.36	12.57	1.73	1.73	0.68
Night Time Preservation Boilers	0.56	0.20	0.95	0.37	0.37	0.10
Emergency Fire Pump Engines[b]	0.27	0.01	0.05	0.0092	0.0092	0.0006
Emergency Generators[b]	1.53	0.11	0.41	0.04	0.04	0.0016
Cooling Towers	--	--	--	0.03	0.03	--
Onsite Maintenance Vehicles[c]	1.61	0.47	1.08	0.07	0.07	0.34
Onsite Maintenance Vehicles Fugitives[c]	--	--	--	21.6	3.42	--
Subtotal of Onsite Emissions[e]	**9.62**	**2.15**	**15.06**	**47.52**	**11.16**	**1.12**
Offsite Emissions[d]	-	-	-	-	-	-
Delivery Vehicles	0.23	0.18	0.15	0.08	0.08	0.004
Employee Vehicles	0.67	0.64	7.50	0.12	0.12	0.01
Subtotal of Offsite Emissions	0.9	0.82	7.65	0.2	0.2	0.014
Total Maximum Annual Emissions	10.52	2.97	22.71	47.72	11.36	1.13
Approved PSPP Emission						
Approved Onsite Emissions	**2.37**	**10.30**	**3.40**	**32.27**	**7.59**	**0.72**
Percent in Onsite Emissions between Proposed and Approved projects	+305%	-79%	+342%	+47%	+47%	-55%

Source: SCAQMD 2013c Facility Emissions Summaries tables and staff estimate for employee vehicles.
a includes both boilers worse case of high boost mode, low mode, and a startup/shutdown per day.
b includes the common area equipment as well as both power plants.
c includes the mirror washing machines (MWMs), (light duty trucks) LDTs, and Water Trucks.
d Palen 2013ff Appendix 4.1A Table 4.1A-11
e SCAQMD emission estimates are different due to the onsite maintenance vehicles emissions included in staffs subtotal of onsite emissions.

~~The project owner submitted a new permit application to the South Coast Air Quality Management District (SCAQMD) on April 4, 2012[7] for the required air permits needed for the project. On May 5, 2013 the SCAQMD sent a letter stating the PSEGS project application is still deemed to be incomplete.[8]~~

~~At this time, staff has evaluated only construction related air quality impacts from the modified project. The operational related impacts will be evaluated during the time of the Final Staff Assessment and once the SCAQMD has published a Determination of Compliance and Energy Commission Staff can then recommend adoption of Air Quality Conditions of Certification.~~

Dispersion Modeling Assessment

While the emissions are the actual mass of pollutants emitted from the proposed modified project, the impacts are the concentration of pollutants from the proposed modified project that reach the ground level. When emissions are expelled at a high temperature and velocity through a relatively tall stack, the pollutants would be greatly diluted by the time they reach ground level. For this proposed modified project, there

~~[7] SCAQMD 2013a – South Coast Air Quality Management District/Mohsen Nazemi (TN 70277). Letter to Roger Johnson, dated April 5, 2013. Submitted to CEC/Dockets Unit on April 11, 2013~~

~~[8] SCAQMD 2013b – South Coast Air Quality Management District/Mohsen Nazemi (TN 70536). Completeness Letter for the Palen Solar Electric Generation Project to Charles Turlinski, dated April 26, 2013. Submitted to CEC/Docket Unit April 30, 2013~~

are no tall emission stacks, but the construction and maintenance vehicles and emergency engine do have high temperature and velocity exhausts; and the boilers also have relatively high exhaust temperatures and velocities. The emissions from the proposed modified project, both stationary source and onsite mobile source emissions, are analyzed through the use of air dispersion models to determine the probable impacts at ground level.

Air dispersion models provide a means of predicting the location and ground level concentrations of the impacts of a new emissions source. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions to provide theoretical maximum offsite pollutant concentrations for short-term (1-hour, 3-hour, 8-hour, and 24-hour) and annual periods. The model results are generally described as maximum concentrations, often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$).

The project owner used the U.S.EPA guideline ARMS/EPA Regulatory Model (AERMOD) model (version12345) as well as preprocessors to determine surface characteristics (AERSURFACE version 13016), process meteorological data (AERMET version 12345), and to determine receptor elevations and hill slop factors (AERMAP version 11103) to estimate ambient impacts from project construction and operation. The construction emission sources for the site were grouped into two categories: combustion exhaust emissions and fugitive dust emissions. Combustion equipment exhaust emissions were modeled as 3.048 meter high point sources (exhaust parameters of 750 Kelvin, 64.681 m/s velocity, and 0.1524m diameter) placed at regular intervals. Construction fugitive dust emissions were modeled as area sources with an effective height of 0.5 meters. Short-term impacts were modeled assuming the emissions were located at the two power blocks, the common area, and for the site preparation phase, the construction and truck staging area. This resulted in seventeen (17) point sources (2 acres/source, located 50-100 meters apart) and area sources approximating the 34 and 26 acre areas discussed above for site preparation and power block and heliostat installation phases, respectively (Palen 2013c).

The inputs for the air dispersion models include two power blocks with stack information (exhaust flow rate, temperature and stack dimensions), specific engine and vehicle emission data and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this proposed modified project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the Blythe Airport meteorological station during 2002 through 2006.

For the determination of one-hour average and annual average construction NOx concentrations, the Ozone Limiting Method (OLM) was used to determine worst-case near field NO_2 impacts. The NOx emissions from internal combustion sources, such as diesel engines, are primarily in the form of nitric oxide (NO) rather than NO_2. The NO converts into NO_2 in the atmosphere, primarily through the reaction with ambient ozone, and NOx OLM assumes full conversion of stack NO emission with the available ambient ozone. NO_2 impacts were computed using the ambient ratio method (ARM) with the USEPA default values of 0.80 and 0.75 for the 1-hour and annual NO2/NOx ratios, respectively.

The project owner has also provided a modeling analysis to show compliance during operation with the new federal 1-hour NO_2 standard[9] (TN 70786). This modeling analysis, also using the AERMOD dispersion model, includes the use of the NOx OLM modeling option and used a post-processor developed by the project owner's consultant to also add in the corresponding hourly NO_2 background data and determine the 98th percentile of daily maximums (eighth highest) for each modeled receptor location. The NOx OLM option considers that the emissions of NOx are initially primarily in the form of NO that over time oxidizes, primarily through a reaction with ozone, to NO_2. ~~Operational impacts will be assessed in the FSA.~~

Staff reviewed the background concentrations provided by the project owner, replacing them where appropriate with the available highest ambient background concentrations from the last three years at the most representative monitoring stations as show in **Air Quality Table 5**. Staff added the modeled impacts to these background concentrations, and then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the proposed modified project's emission impacts would cause a new exceedance of an ambient air quality standard or would contribute to an existing exceedance.

The following sections discuss the proposed modified project's short-term direct construction ambient air quality impacts, as estimated by the project owner, and describes appropriate mitigation measures.

Construction Impacts and Mitigation

Construction Modeling Analysis

Using estimated peak hourly, daily and annual construction equipment exhaust emissions, the project owner modeled the proposed modified project's construction emissions to determine impacts (Palen 2013c). To determine the construction impacts on ambient standards (i.e. 1-hour through annual), construction was assumed to occur for 12 hours/day (8 AM to 8 PM), which represents an average of the workday periods which would fluctuate between 8 and 16 hours per day. The construction impacts modeling analysis used the same meteorological data and other modeling inputs as used for the project operating impact analysis. However, for the construction modeling, only the facility fence line and nearby downwash receptor grid (used for operational impacts) were used (both with 50-meter spacing), since maximum impacts would occur in the immediate vicinity of the property boundary due to the low plume heights during construction.

The predicted proposed modified project pollutant concentration levels were added to conservatively worst-case maximum background concentration levels (from **Air Quality Table 5**) to determine the cumulative effect. The results of the project owner's modeling analysis are presented in **Air Quality Table 10**. The construction emissions modeling analysis, including both the onsite fugitive dust and vehicle tailpipe emission sources

[9] Palen 2013n – Galati Blek/J. Leyva Record (TN 70786). Palen Solar Electric Air Quality Modeling Files, dated May 7, 2013. Submitted to CEC/Docket Unit on May 7, 2013

(with project owner-proposed control measures) are summarized in **Air Quality Tables 6** and **7**.

Air Quality Table 10
Maximum Project Construction Impacts

Pollutants	Avg. Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr.	200.6	~~92.3~~124.3	~~292.9~~324.9	339	~~86~~95%
	Fed.1 hr (98^{th} percentile)	168.6	~~84.6~~97.8	~~253.26~~266.4	188	**~~135~~141%**
	Annual	0.7	~~17~~22.6	~~17.7~~23.3	57	~~31~~40%
CO	1-hr	131	3,450	3581	23,000	16%
	8-hr	52	744	796	10,000	8%
PM10	24	15.3	133	148.3	50	**297%**
	Annual	0.10	23.2	23.3	20	**117%**
PM2.5	24	3.4	26.3	29.7	35	85%
	Annual	0.05	7.2	7.25	12	60%
SO_2	1-hr	0.33	28.7	29.03	665	4%
	3-hr	0.21	15.6	15.81	1,300	1%
	24-hr	0.07	18.4	18.47	105	18%
	Annual	0.01	2.9	2.91	80	4%

Source: Palen 2013c
Notes: [a] – This is the background concentration that corresponds with the hour with the highest combined matched hourly project impact and hourly monitored NO_2 background concentration.
[b]98^{th} percentile NOx 1-hour OLM = 168.6 ug/m3 (Palen 2013n)

This modeling analysis indicates, with the exception of PM10 and Federal 1-hour NO_2, that the proposed modified project would not create new exceedances or contribute to existing exceedances for any of the modeled air pollutants. The conditions that would create worst-case project modeled impacts (low wind speeds) are not the same conditions when worst-case background is expected for PM10. Additionally, the worst-case PM10 impacts occur at the fence line and drop off quickly with distance from the fence line. In light of the existing PM10 non-attainment status for the project site area, staff considers the construction PM10 emissions to be potentially CEQA significant and recommends that the off-road equipment and fugitive dust PM10 emissions be mitigated pursuant to CEQA.

The project owner's modeling results indicate that 1-hour NO_2 concentrations above the federal standard only occur within 200 meters of the north fence line at night. Staff believes that these results are conservative and over predict the impacts for project construction for the following reasons:

- The modeling analysis included the very conservative input assumptions of using area sources to model all of the construction NOx emissions, except for the concrete batch plant generator which was modeled as a point source and consequently found to have minimal NO_2 impacts (less than 3 μg/m3);~~.~~
- The project itself would not cause a violation of the standard and only when added to the 98^{th} percentile background value would the impacts be over the standard;~~.~~
- Total concentrations shown in this table are the sum of the maximum predicted impact and the maximum measured background concentration. Because the maximum impact would most likely not occur at the same time as the maximum background concentration, the actual maximum combined impact would be lower;~~.~~

- The modeling, which did incorporate the ozone limiting method (OLM), did not undergo further refinement to determine the actual expected maximum conversion of NO to NO_2 in the very short time period the emissions plume would take to get to and just past the fence line. OLM assumes immediate 100 percent conversion based on the available concentration of ozone; and~~.~~
- The entire construction period is expected to be 33 months in duration, while the federal 1-hour NO_2 standard is averaged over 36 months.

However, to be certain that there would be no risk to public health from construction NOx, emissions staff recommends that the off-road construction equipment be mitigated by requiring the use of equipment that meets the latest U.S. EPA and ARB engine emission standards.

Staff concludes with implementation of staff-proposed mitigation measures the construction impacts would not contribute substantially to exceedances of PM10 ~~or ozone standards~~, nor cause new exceedances of the 1-hour federal NO_2 standard.

The modeling analysis shows that, after implementation of the recommended emission mitigation measures, the proposed modified project's construction is not predicted to cause new exceedances of the AAQS.

Adequacy of Current Mitigation as adopted in the original CEC Palen Decision

Staff will propose retaining Air Quality Conditions of Certification **AQ-SC1** through **AQ-SC5** with some modifications and updates that have been used in more recent solar projects.

Staff Proposed Mitigation

Staff recommends the project owner's proposed construction mitigation be formalized, with minor modifications that update the measures to meet current staff recommendations, in Air Quality Conditions of Certification **AQ-SC1** through **AQ-SC5**. Staff has determined that these Conditions of Certification would mitigate all construction air quality impacts of the proposed modified project to less than significant levels pursuant to CEQA.

Staff has considered the minority population surrounding the site (see **Socioeconomics Figure 1**). Since the proposed modified project's direct air quality impacts have been reduced to less than significant, there is no environmental justice issue for air quality.

Operation Impacts and Mitigation

The following section discusses the proposed modified project's direct operating ambient air quality impacts, as estimated by the applicant and evaluated by staff. Additionally, this section discusses recommended mitigation measures for operation.

Operation Modeling Analysis

Using estimated peak hourly, daily and annual operating emissions, the applicant modeled the proposed modified project's operation emissions to determine impacts. The predicted proposed modified project pollutant concentration levels were added to conservatively estimate worst-case maximum background concentration levels (**Air**

Quality Table 5) to determine the cumulative effect. **Air Quality Table 11** presents the results of the applicant's modeling analysis. The operation modeling analysis includes emissions from the stationary sources for both power blocks and the onsite fugitive dust and vehicle tailpipe emission sources estimated by the applicant, which all include the applicant's proposed control measures and resulting emissions that are summarized in **Air Quality Tables 8** and **9**.

Air Quality Table 11
Project Operation Emission Impacts

Pollutants	Avg. Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr CAAQS	177.4	124.3	301.7	339	88%
	1-hr NAAQS	5.1	97.8	102.9	188	55%
	Annual	0.20	22.6	22.8	57	40%
CO	1-hr	253.0	3,450	3,703	23,000	16%
	8-hr	12.6	744	756.6	10,000	8%
PM10	**24**	**3.30**	**133**	**136.3**	**50**	**272%**
	Annual	**0.58**	**23.2**	**23.8**	**20**	**119%**
PM2.5	24	0.67	26.3	27.0	35	77%
	Annual	0.11	7.2	7.3	12	61%
SO_2	1-hr	1.39	28.7	30.0	665	4.5%
	3-hr	0.69	15.6	16.3	1,300	1%
	24-hr	0.15	18.4	18.5	105	17.5%
	Annual	0.008	2.9	2.9	80	2%

Source: June Supplemental Information Palen 2013ff.

This modeling analysis indicates, with the exception of PM10 impacts, that the proposed modified project would not create new exceedances nor contribute to existing exceedances for any of the modeled air pollutants. The conditions that would create worst-case project modeled impacts (low wind speeds) are not the same conditions when worst-case background is expected for PM10. Additionally, the worst-case PM10 impacts occur at the fence line and drop off quickly with distance from the fence line. Therefore, staff concludes that the operation impacts, when considering staff's mitigation measures would not contribute substantially to exceedances of the PM10 CAAQS.

However, in light of the existing PM10 and ozone California non-attainment status for the project site area, staff considers the operation NOx, VOC, and PM emissions to be potentially CEQA significant and recommends that the off-road equipment and fugitive dust emissions be mitigated pursuant to CEQA.

The modeling analysis shows that, after implementation of the recommended emission mitigation measures, the proposed modified project's operation is not predicted to cause new exceedances of the state or federal AAQS.

Operations Mitigation

Applicant's Proposed Mitigation

Emission Controls

The applicant proposes the following Best Available Control Technology (BACT) emission controls on the stationary equipment associated with the PSEGS:

Auxiliary Boilers

The applicant has proposed one 249.0 mmBtu per hour auxiliary boiler per power plant unit, which would be fired only on natural gas. The auxiliary boiler would be vented to SCR and NOx concentration would be limited to 5 ppmv; CO concentration would be limited to 25 ppmv; The criteria pollutant emission factors used for the NOx and CO emission estimates are based ≤ 5 ppmv and ≤ 25 ppmv respectively, each at 3% O2, dry basis. Annual operation of each auxiliary boiler would be limited to 307 mmcf annual fuel usage. The maximum annual fuel usage is based on solar boosting mode (220 day/yr), non-boosting mode (120 day/yr), ten cold starts, five very cold starts, and 60 boosting/emergency starts per year (see condition for definition). The boilers would have the following fuel limits, each:

- Monthly fuel usage: 40 mmcf/month (AQ-19)
- Commissioning fuel usage: 4.28 mmcf/month (AQ-19)
- Yearly fuel usage-non commissioning year: 307 mmcf/yr (AQ-20)
- Yearly fuel usage commissioning year: 311 mmcf/yr (AQ-20)

Selective Catalytic Reduction (SCR)/CO Catalyst Systems

The SCR catalyst would use ammonia injection into the catalyst to reduce NOx. The subsequent chemical reaction would reduce NOx to elemental nitrogen (N2) and water, resulting in NOx concentrations in the exhaust gas no greater than 5 ppmvd at 3% O2 on a 15 min average. The CO oxidation catalyst would be installed within the catalyst housing which would reduce CO in the exhaust gas to no greater than 25 ppmvd at 3% O2, on a 15 minute average. The proposed SCR/CO catalyst systems would have the following limits:

- NOx: 5 ppmv @ 3% oxygen at stack outlet
- CO: 25 ppmv @ 3% oxygen at stack outlet
- Ammonia Slip: 5 ppmv @ 3% oxygen, 0.68 lb/hr, 894 lb/yr

Night Time Preservation Boilers

The applicant has proposed one 10.5 mmBtu per hour nighttime preservation boiler per power plant unit, which would be fired on natural gas. Each nighttime preservation boiler would be equipped with ultra-low-NOx ppmv burners and CO concentration limit of 25 ppmv; Daily emissions based on 14 hrs/day of normal operation (annual average) and annual operation of each boiler would be based on 48 mmcf annual fuel usage. Monthly operation of each boiler would be based on 4.34 mmcf fuel usage. The proposed boilers would have the following maximum fuel limits, each:

- Monthly fuel usage: 4.34 mmcf/month (AQ-39)
- Commissioning fuel usage: 0.11 mmcf/month (AQ-40)
- Yearly fuel usage: 48 mmcf/yr (AQ-41)

Fire Water Pump Engines

The applicant has proposed one 617 bhp fire water pump engine per power plant unit, which would be fired on ARB diesel fuel with no more than 15 ppm sulfur content. The applicant has proposed ARB/EPA Tier 3 engines, compliant with the New Source Performance Standards, Subpart IIII Standards of Performance for

Stationary Compression Ignition Internal Combustion Engines, for the fire water pumps. The proposed ARB/EPA Tier 3 engines would have the following emission guarantees:

- NMHC + NOx: 2.7 gram/bhp-hour
- CO: 2.6 gram/bhp-hour
- PM10/PM2.5: 0.09 gram/bhp-hour

Large Emergency Generators

The applicant has proposed one 3,633 brake horsepower (bhp) emergency generator engine per power plant unit, which would be fired on ARB diesel fuel with no more than 15 ppm sulfur content. The applicant has proposed ARB/EPA Tier 2 engines, compliant with the New Source Performance Standards, Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, for the emergency generators. The proposed ARB/EPA Tier 2 engines would have the following emission guarantees:

- NMHC + NOx: 3.95 gram/bhp-hour
- CO: 0.89 gram/bhp-hour
- PM10/PM2.5: 0.09 gram/bhp-hour

Small Emergency Generator

The applicant has proposed one 398 brake horsepower (bhp) emergency generator engine per power plant unit for the common area, which would be fired on ARB diesel fuel with no more than 15 ppm sulfur content. The applicant has proposed a ARB/EPA Tier 3 engine, compliant with the New Source Performance Standards, Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, for the emergency generator. The proposed ARB/EPA Tier 3 engine would have the following emission guarantees:

- NMHC + NOx: 2.79 gram/bhp-hour
- CO: 2.31 gram/bhp-hour
- PM10/PM2.5: 0.11 gram/bhp-hour

Cooling Towers

The applicant has proposed one four-cell cooling tower per power plant unit, which would be used for auxiliary equipment cooling. The cooling towers would each have a high efficiency drift eliminator guaranteed to control drift to 0.0005% of the water recirculation rate. Additionally, the cooling tower recirculating water would be controlled to a maximum total dissolved solids content of 1,500 mg/l. The cooling towers would have the following emission limits, each:

- PM10/PM2.5: 0.18 lb/day, 0.3 tons/year

Operation and Maintenance Vehicles

The applicant has stipulated to conditions recommended by staff for other recent large solar power projects to control maintenance vehicle emissions, which states the following vehicle requirements:

- The project owner would use gasoline powered light trucks, equivalent to the Ford F150 model, for facility maintenance, except for mirror washing, welding rigs, or other specific activities which require a larger vehicle;
- Only new trucks meeting California on-road vehicle emission standards would be purchased for use at the site; and
- The applicant has stipulated to staff's previously recommended fugitive dust control condition for operation that includes the same mitigation measures as required during construction, as appropriate.

Emission Offsets

The District has determined NOx emissions, shown in **Air Quality Table 9** above, are greater than the 4 ton per year exemption thresholds. Therefore, the NOx emissions are required to be offset in accordance with Rule 1303(b)(2). The applicant submitted a written request on 7/12/13 to opt into the NOx RECLAIM program to mitigate NOx emission, thus NOx ERC's are not required. The VOC, SOx and PM10 emissions have a Facility Exemption from Rule 1303 (b)(2) per Rule 1304 (d)(1)(A). In addition, note that the non-RECLAIM pollutants for the emergency internal combustion engines are exempt from offsets under SCAQMD Rule 1304(a)(4). Compliance is expected.

Adequacy of Proposed Mitigation

Staff concurs with the District's determination that the proposed modified project's stationary source emission controls/emission levels for criteria pollutants meet all regulatory requirements. Staff believes the proposed stationary source emission levels are mitigated adequately. The applicant will be required to provide RECLAIM trading credits prior to operation. However, the District does not require permits for the cooling tower, so staff recommends staff condition **AQ-SC10** to formalize the applicant's stipulated PM10 mitigation measure for this emission source.

Staff concludes other offsets are not required as CEQA mitigation, consistent with staff's findings of other solar projects, because: 1) the project is located in a federal ozone attainment area and the project's relatively low level of emissions would not impact that status; 2) the project will enable indirect emission reductions from fossil fuel fired power plants; and 3) the project is implementing Best Available Control Technology for the stationary emission sources and staff has recommended additional measures (**AQ-SC6**) to mitigate the operating vehicles exhaust emissions.

Additionally, staff generally agrees that the applicant's proposed fugitive dust mitigation measures would provide adequate fugitive dust emission control.

Staff Proposed Mitigation

As mentioned above for the ozone and PM10 impacts, staff concludes that the proposed modified project's direct stationary source ozone precursor and PM10 emissions are minimal, but when combined with the maintenance vehicles emissions could be significant. Additionally, staff concludes that a solar renewable project, which would have a 30-year life in a setting likely to continue to be impacted by both local and upwind emission sources, should address its contribution to the potentially ongoing nonattainment of PM10 and ozone ambient air quality standards. Staff concludes that the applicant's proposed mitigation measures, that mirror staff's currently recommended mitigation requirements for other large solar projects, would adequately mitigate the proposed modified project's stationary source, mobile equipment, and fugitive dust emissions. Therefore, staff recommends the operating mitigation requirements be formalized, with minor modifications to meet current staff recommendations, in staff Conditions of Certification **AQ-SC6** and **AQ-SC7**.

Staff also proposes Condition of Certification **AQ-SC8** to ensure that the Energy Commission license is amended as necessary to incorporate changes to the air quality permits.

Finally, staff is recommends an additional condition for the cooling towers that are not included in the SCAQMD permit. Proposed Condition of Certification **AQ-SC10** would require that the proposed cooling towers have high efficiency mist eliminators and require the applicant to test and control recirculating water total dissolved solids content to reduce particulate emissions from the cooling towers.

Staff has determined that the proposed emission controls and emission levels, along with the applicant proposed and staff recommended emission mitigation measures, would mitigate all proposed modified project air quality impacts to less than significant pursuant to CEQA.

Staff has considered the minority population surrounding the site (see **Socioeconomics Figure 1**). Since the proposed modified project's direct air quality impacts have been reduced to less than significant, there is no environmental justice issue for air quality.

Indirect Pollutant and Secondary Pollutant Impacts

The proposed modified project would have direct emissions of chemically reactive pollutants (NOx, SOx, and VOC), but would also have indirect emission reductions associated with the reduction of fossil fuel–fired power plant emissions due to the proposed modified project displacing the need for their operation, since solar renewable energy facilities would operate on a must-take basis.[10] However, the exact nature and location of such reductions is not known, so the discussion below focuses on the direct emissions from the proposed modified project within the Riverside County portion of the Mojave Desert Air Basin.

Ozone Impacts

There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the model to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, it can be said that the emissions of NOx and VOC from the PSEGS project do have the potential (if left unmitigated) to contribute to higher ozone levels in the region. These impacts would be cumulatively significant under CEQA because they would contribute to ongoing violations of the state ozone ambient air quality standards.

---

[10] This refers to the fact that the contract between the owner of this solar power facility and the utility will require that the utility take all generation from this facility with little or no provisions to turn down generation from the facility.

PM2.5 Impacts

Secondary particulate formation, which is assumed to be 100 percent PM2.5, is the process of conversion from gaseous reactants to particulate products. The process of gas-to-particulate conversion, which occurs downwind from the point of emission, is complex and depends on many factors, including local humidity and the presence of air pollutants. The basic process assumes that the SOx and NOx emissions are converted into sulfuric acid and nitric acid first and then react with ~~ambient~~ ammonia to form sulfate and nitrate. The sulfuric acid reacts with ammonia much faster than nitric acid and converts completely and irreversibly to particulate form. Nitric acid reacts with ammonia to form both a particulate and a gas phase of ammonium nitrate. The particulate phase would tend to fall out; however, the gas phase can revert back to ammonia and nitric acid. Thus, under the right conditions, ammonium nitrate and nitric acid establish a balance of concentrations in the ambient air.

The emissions of NOx and SOx from PSEGS do have the potential (if left unmitigated) to contribute to higher PM2.5 levels in the region; however, the region is attainment for PM2.5 standards and the low level of NOx and SOx emissions from the proposed modified project would not significantly impact that status.

Impact Summary

The project owner is proposing to mitigate the proposed modified project's stationary source NOx, VOC, SO_2, and PM10/PM2.5 emissions through the use of Best Available Control Technology (BACT) and reduce the proposed modified project's mobile source emissions by using lower emitting new vehicles. With Condition of Certification **AQ-SC5,** staff concludes that the proposed modified project would not cause significant secondary pollutant impacts ~~during construction~~.

PROJECT-RELATED ACTIONS – AIR QUALITY

In order to transmit the power generated at the PSEGS to the electricity grid, a new substation is required. Southern California Edison Company (SCE) is constructing the substation and will operate it, which would allow PSEGS's electricity to be carried by the Devers-Palo Verde No. 1 (DPV1) 500 kV transmission line. SCE's web site states that the Red Bluff Substation Project is scheduled to become operational in December 2013[11].

CUMULATIVE IMPACTS

Cumulative impacts are defined by CEQA as "two or more individual effects which, when considered together, are considerable or...compound or increase other environmental impacts." (CEQA Guidelines, § 15355.) A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts." (CEQA Guidelines, § 15130(a)(1).) Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

---

[11] (SEC 2013a - https://www.sce.com/wps/portal/home/about-us/reliability/upgrading-transmission/red-bluff)

This analysis is concerned with criteria air pollutants. Such pollutants have impacts that are usually (though not always) cumulative by nature. Rarely would a project by itself cause a violation of a federal or state criteria pollutant standard. However, a new source of pollution may contribute to violations of criteria pollutant standards because of high existing background concentrations or foreseeable future projects. Air districts attempt to attain the criteria pollutant standards by adopting attainment plans, which comprise a multi-faceted programmatic approach to such attainment. Depending on the air district, these plans typically include requirements for emissions offsets and the use of Best Available Control Technology (BACT) for new sources of emissions, and restrictions of emissions from existing sources of air pollution.

Thus, much of the preceding discussion is concerned with cumulative impacts. The "Existing Ambient Air Quality" subsection describes the air quality background in the Riverside County portion of the MDAB, including a discussion of historical ambient levels for each of the significant criteria pollutants. The "Construction Impacts and Mitigation" subsection discusses the proposed modified project's contribution to the local existing background caused by project construction. The "Operation Impacts and Mitigation" subsection discusses the proposed modified project's contribution to the local existing background caused by project operation. The following subsection includes two additional analyses:

- a summary of projections for criteria pollutants by the air district and the air district's programmatic efforts to abate such pollution; and
- an analysis of the proposed modified project's *localized cumulative impacts*, the proposed modified project's direct operating emissions combined with other local major emission sources.

SUMMARY OF PROJECTIONS

The SCAQMD is the agency with principal responsibility for air quality attainment planning in the portion of the MDAB surrounding the project site. The project site area is considered attainment or unclassifiable for all federal air quality standards, so for the MDAB portion of SCAQMD's jurisdiction, there are no federal planning requirements. However, this area is non-attainment for state ozone and PM10 standards, where there are state planning requirements for ozone attainment, but not PM10 attainment. SCAQMD has adopted three recent Air Quality Management Plans. These adopted air quality plans are summarized below.

- **2012 Air Quality Management Plan** (adopted January 2013 by ARB, not yet approved by U.S.EPA) Link: www.aqmd.gov/aqmp/2012aqmp/index.htm
- **2007 Air Quality Management Plan** (adopted 6/1/2007, ~~not yet approved by U.S.EPA~~ approved by U.S. EPA on July 14, 2011) Link: www.aqmd.gov/aqmp/07aqmp/index.html
- **Final 2003 Air Quality Management Plan** (originally adopted 12/10/1999, amended in 2003, partially approved/partially disapproved by U.S.EPA in 2009.) Link: www.aqmd.gov/aqmp/AQMD03AQMP.htm

These three plans extensively cover the attainment planning requirements for the South Coast Air Basin, and provide a separate chapter covering attainment planning for the portion of the Salton Sea Air Basin within SCAQMD ~~jurisdiction~~ boundaries. However, these plans do not mention any specific state ozone attainment planning requirements for the portion of the MDAB within SCAQMD jurisdiction. PM10 attainment planning documents are not required by the state.

2012 Air Quality Management Plan

The primary purpose of the 2012 AQMP is to bring the South Coast Air Basin into attainment with federal health-based standards for unhealthful fine particulate matter (PM2.5) by 2014. To have a reasonable expectation of meeting the 2023 ozone deadline, the scope and pace of continued air quality improvement must greatly intensify. The federal Clean Air Act requires a 24-hour PM2.5 nonattainment area to prepare a State Implementation Plan (SIP). This was submitted to U.S. EPA on December 14, 2012. The SIP must demonstrate attainment with the 24-hour PM2.5 standard by 2014, with the possibility of up to a five-year extension to 2019, if needed. The District's SIP indicates that the area would meet the 24-hour PM2.5 standard by the end of 2014.

2007 Air Quality Management Plan

The Final 2007 Air Quality Management Plan (AQMP) control measures consist of four components: 1) the District's Stationary and Mobile Source Control Measures; 2) ARB's Proposed State Strategy; 3) District Staff's Proposed Policy Options to Supplement ARB's Control Strategy; and 4) Regional Transportation Strategy and Control Measures provided by SCAG. None of the specified control measures directly impact PSEGS emission sources beyond existing regulations and permit requirements.

2003 Air Quality Management Plan

The SCAQMD amended the 1997 AQMP in 1999 to address the U.S. EPA's proposed disapproval of the 1997 Ozone SIP revision to ensure that the 1997 AQMP complied with or exceeded federal requirements. The 1999 AQMP amendments to the 1997 AQMP were subsequently approved by the U.S. EPA into the SIP in April 2000. The SCAQMD updated the PM10 portion of the 1997 AQMP for both the South Coast Air Basin and Coachella Valley in 2002 as part of the District's request to extend the PM10 attainment date from 2001 to 2006 for these areas as allowed under the federal Clean Air Act (CAA). The U.S. EPA approved the 2002 update on April 18, 2003.

The purpose of the 2003 Revision to the AQMP for the South Coast Air Basin (Basin) and those portions of the Salton Sea Air Basin under SCAQMD jurisdiction is to set forth a comprehensive program that will lead these areas into compliance with all federal and state air quality planning requirements. Specifically, the 2003 AQMP Revision is designed to satisfy the California Clean Air Act (CCAA) triennial update requirements and fulfill the District's commitment to update transportation emission budgets based on the latest approved motor vehicle emissions model and planning assumptions. ~~The Plan will be submitted to U.S. EPA as a SIP revision once it is approved by the SCAQMD Governing Board and the California Air Resources Board (CARB).~~

The control measures specified in the 2003 AQMP are similar to those specified in the 2007 AQMP. Again, the specified control measures do not directly impact PSEGS emission sources beyond the existing SCAQMD regulations and permit requirements.

Summary of Conformance with Applicable Air Quality Plans

The applicable air quality plans do not outline any new control measures applicable to the proposed modified project's construction or operating emission sources. Therefore, compliance with existing District rules and regulations would ensure compliance with those air quality plans.

Localized Cumulative Impacts

Since the power plant air quality impacts can be reasonably estimated through air dispersion modeling (see the "Operation Modeling Analysis" subsection) the proposed modified project's contributions to localized cumulative impacts can be estimated. To represent *past* and, to an extent, *present projects* that contribute to ambient air quality conditions, the Energy Commission staff recommends the use of ambient air quality monitoring data (see the "Existing Ambient Air Quality" subsection), referred to as the *background*. The staff takes the following steps to estimate what are additional appropriate "present projects" that are not represented in the background and "reasonably foreseeable projects":

- First, the Energy Commission staff (or the project owner) works with the air district to identify all projects that have submitted, within the last year of monitoring data, new applications for an authority to construct (ATC) or permit to operate (PTO) and applications to modify an existing PTO within 6 miles of the project site. Based on staff's modeling experience, beyond 6 miles there is no statistically significant concentration overlap for non-reactive pollutant concentrations between two stationary emission sources.

- Second, the Energy Commission staff (or the project owner) works with the air district and local counties to identify any new area sources within 6 miles of the project site. As opposed to point sources, area sources include sources like agricultural fields, residential developments or other such sources that do not have a distinct point of emission. New area sources are typically identified through draft or final Environmental Impact Reports (EIRs) that are prepared for those sources. The initiation of the EIR process is a reasonable basis on which to determine what is "reasonably foreseeable" for new area sources.

- The data submitted, or generated from the applications with the air district for point sources or initiating the EIR process for area sources, provides enough information to include these new emission sources in air dispersion modeling. Thus, the next step is to review the available EIR(s) and permit application(s), determine what sources must be modeled and how they must be modeled.

- Sources that are not new, but may not be represented in ambient air quality monitoring are also identified and included in the analysis. These sources include existing sources that are co-located with or adjacent to the proposed source (such as an existing power plant). In most cases, the ambient air quality measurements are not recorded close to the proposed modified project, thus a local major source might not be well represented by background air monitoring data. When these sources are included, it is typically a result of there being an existing source on the project site and the ambient air quality monitoring station being more than 2 miles away.

- The modeling results must be carefully interpreted so that they are not skewed towards a single source in high impact areas near that source's fence line. It is not truly a cumulative impact of PSEGS if the high impact area is the result of high fence line concentrations from another stationary source and PSEGS is not providing a substantial contribution to the determined high impact area.

Once the modeling results are interpreted, they are added to the background ambient air quality monitoring data and thus the modeling portion of the cumulative assessment is complete. Due to the use of air dispersion modeling programs in staff's cumulative impacts analysis, the project owner must submit a modeling protocol, based on information requirements for an application, prior to beginning the investigation of the sources to be modeled in the cumulative analysis. The modeling protocol is typically reviewed, commented on, and eventually approved in the discovery phase of the licensing procedure. Staff typically assists the project owner in finding sources (as described above), characterizing those sources, and interpreting the results of the modeling. However, the actual modeling runs are usually left to the project owner to complete. There are several reasons for this: modeling analyses take time to perform and require significant expertise, the project owner has already performed a modeling analysis of the proposed modified project alone (see the "Operation Modeling Analysis" subsection), and the project owner can act on its own to reduce stipulated emission rates and/or increase emission control requirements as the results warrant. Once the cumulative project emission impacts are determined, the necessity to mitigate the proposed modified project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or the project owner (see the "Operation Mitigation" subsection).

Since the PSA was published there have been a number of new projects added to the Executive Summary Attachment A Tables 1-3 lists and Executive Summary Attachment A - Figure 1. While the list has not added any projects within the six-mile buffer required for cumulative modeling analysis, there are two projects with 7 miles of the PSEGS. These projects are Desert Lily Soleil Project 100 MW PV plant on 1,216 acres of BLM land, and Chuckwalla Solar I, a 200 MW solar PV project on 4,083 acres. The potential for significant additional development within the air basin and corresponding increase in air basin emissions is a major part of staff's rationale for recommending Conditions of Certification **AQ-SC6** and **AQ-SC7** that are designed to mitigate the proposed modified project's cumulative impacts by reducing the dedicated on-site vehicle emissions and fugitive dust emissions during site operation. With these recommended CEQA-only mitigation measures, staff has concluded that the CEQA cumulative air quality impacts are less than significant.

Staff has considered the minority population surrounding the site (see **Socioeconomics Figure 1**). Since the proposed modified project's cumulative air quality impacts have been mitigated to less than significant, there is no environmental justice issue for air quality.

COMPLIANCE WITH LORS

The South Coast Air Quality Management District (SQAQMD) issued a Preliminary Determination of Compliance (PDOC) for the PSEGS on October 18, 2013 (SCAQMD 2013c), and will issue a Final Determination of Compliance (FDOC) after a public notice period. Compliance with all District rules and regulations was demonstrated to the District's satisfaction in the PDOC. The District's PDOC conditions are presented in the Conditions of Certification (**AQ-1** to **AQ-60**).

Staff may submit an official PDOC comment letter and expects that the FDOC would contain revisions to conditions due to Energy Commission, applicant, or third party comments, and staff will provide a Staff Assessment addendum with any revised FDOC findings or conditions of certification. Once the FDOC is published and staff has included any needed changes in the Final Staff Analysis (FSA), the Energy Commission would be able to move forward with a Decision.

FEDERAL

The District is responsible for issuing the ~~federal~~ Federal New Source Review (NSR) permit and has been delegated enforcement of the applicable New Source Performance Standards (Subparts Dc, Db and IIII). ~~However, this proposed modified project does not require a federal NSR or Title V permit and furthermore this proposed modified project would not require a Prevention of Significant Deterioration (PSD) permit from U.S.EPA prior to initiating construction.~~

The proposed modified project requires the approval of a federal agency (BLM), but the site is located in an area that is in attainment or unclassified with all federal ambient air quality standards. Therefore, the proposed modified project is not subject to general conformity regulations (40 CFR Part 93).

STATE

The project owner ~~will demonstrate~~ demonstrated the proposed modified project would comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury, as confirmed in the District's ~~Final~~ Determination of Compliance and the Energy Commission's affirmative finding for the project.

The emergency generators and fire water pump engines are also subject to the Airborne Toxic Control Measure (ATCM) requirements for stationary compression ignition engines. This measure limits the types of fuels allowed, established maximum emission rates, and establishes recordkeeping requirements. The ATCM was amended October 2010 and the requirement for Tier 4 and Tier 4i engine was removed from section 93115.6(a)(3)(A)(1)(a) Table 1. Table 1 keeps the current Tier 2 and Tier 3 emissions standards for the applicable HP engine group. The ARB in November 2010 distributed a regulatory advisory that provided guidance on compliance with ATCM. This became effective on May 19, 2011 when the California Office of Administration (OAL) approved the ARB rulemaking for the amendment to ATCM. The proposed emergency engines and fire water pump engines meet the current emission limit requirements of this measure. This measure would also limit the engines' readiness testing and maintenance operation to no more than 50 hours per year.

LOCAL

The District rules and regulations specify the emissions control and offset requirements for new sources such as the PSEGS. Best Available Control Technology would be implemented. Compliance with the District's new source requirements would ensure that the proposed project would be consistent with the strategies and future emissions anticipated under the District's air quality attainment and maintenance plans.

The applicant provided an air quality permit application to the SCAQMD and the District issued a PDOC on October 18, 2013 (SCAQMD 2013c). The PDOC states that the proposed project is expected to comply with all applicable District rules and regulations. The DOC evaluates whether and under what conditions the proposed project would comply with the District's applicable rules and regulations, as described below.

Regulation IV – Prohibitions

Rule 401 – Visible Emissions

This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. The applicant would use equipment configured with BACT and would be burning natural gas in the boilers Therefore, during normal operation, no visible emissions are expected. The emergency engines complies with BACT and would be using a ultra low sulfur fuel; visible emissions not expected during normal operations. ~~This rule limits visible emissions from emissions sources, including stationary source exhausts and fugitive dust emission sources. Compliance with this rule is expected. In the PDOC~~ The District has determined in the PDOC that the facility is expected to comply with this rule. ~~for PSPP (Palen Solar Power Plant, the previously-approved solar trough configuration of this project), the District determined that the facility is expected to comply with this rule. This conclusion is also expected for PSEGS.~~

Rule 402 – Nuisance

This rule restricts discharge of emissions that would cause injury, detriment, annoyance, or public nuisance. Due to the application of BACT on each emission source and the distance from the emission sources to any potential receptors, the project would comply with this rule. ~~The facility is expected to comply with this rule~~ (identical to California Health and Safety Code 41700).

Rule 403 – Fugitive Dust

This rule limits fugitive emissions from certain bulk storage, earthmoving, construction and demolition, and manmade conditions resulting in wind erosion. With the implementation of recommended Air Quality Conditions of Certification **AQ-SC3** and **AQ-SC4**, the facility is expected to comply with this rule.

~~Rule 404 – Particulate Matter Concentration~~

~~The rule limits particulate matter (PM) emissions based on the volume discharge rate. The PSEGS stationary sources would be subject to this rule (auxiliary boilers, and emergency engines) and would need to comply with the PM concentration limits of this regulation. Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS.~~

Rule 407 – Liquid and Gaseous Air Contaminants

This rule limits CO emissions to 2,000 ppmvd and SO_2 emissions to 500 ppmvd, averaged over 15 minutes. For CO, the natural gas fired boilers the applicant proposes a limit of 25 ppmvd @ 15% O_2, for all four boilers. The boilers would be conditioned as such and would be required to verify compliance testing per Rule 1146 and Rule 1303 (a). For SO_2, equipment which complies with Rule 431.1 is exempt from the SO_2 limit in Rule 407. The applicant would be required to comply with Rule 431.1 and thus the SO_2 limit in Rule 407 would not apply. Per section (b)(2) the emergency engines are not subject to this rule.

Rule 409 – Combustion Contaminants

This rule limits discharge into the atmosphere from fuel burning equipment combustion contaminants exceeding in concentration at the point of discharge, 0.1 grain per cubic foot of gas calculated to 12% of carbon dioxide (CO_2) at standard conditions averaged over a minimum of 15 consecutive minutes. The PSEGS stationary sources such as the auxiliary boiler, and the night time preservation boilers would have particulate concentrations below the limit of this rule. ~~Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS.~~ The facility is expected to comply with this rule.

~~Rule 429 – NOx Exemptions for Startup/Shutdown~~

~~Rule 429 limits NOx exemptions for boilers subject to Rule 1146 for periods of startup and shutdown. Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS.~~

Rule 431.1 – Sulfur Content of Gaseous Fuels

Rule 431.1 limits discharge into the atmosphere of sulfur compounds from the burning of gaseous fuels. The boilers would use pipeline quality natural gas which would comply with the 16 ppm sulfur limit, calculated as H_2S, specified in this rule. Natural gas would be supplied by the Southern California Gas Company. The facility proposed an H_2S content of 0.75 gram/100 standard cubic foot, which is equivalent to a concentration of about 12 ppm. It is also much less than the 1 gram/100 standard cubic foot limit typical of pipeline quality natural gas. Compliance is expected. The applicant would comply with the reporting and record keeping requirements as outlined in subdivision (e) of this Rule.

Rule 431.2 – Sulfur Content of Liquid Fuels

Rule 431.1 limits discharge into the atmosphere of sulfur compounds from the burning of liquid fuels. ~~Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS.~~ Any fuel oil combusted in the emergency engines must comply with the rule limit of 15 ppm sulfur. The emergency engines are required to use a low sulfur fuel in the units which complies with the sulfur limits of this rule. The boilers are not using any stand-by fuel, thus they are not subject to this Rule.

~~Rule 463 – Organic Liquids Storage~~

~~This rule sets standards for storage of organic liquids with a true vapor pressure of 1.5 pounds per square inch or greater. The project would store insulating mineral oil (for transformers), hydraulic oil (for steam turbine and other equipment), lubricating oil, and diesel fuel on site, all of which have combined storage vessel capacities and true vapor pressures that are below the applicability thresholds for this rule. Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS.~~

Rule 474 – Fuel Burning Equipment – Oxides of Nitrogen

This rule limits NOx emission concentrations from stationary sources, with specific concentration levels being based on heat input rates and fuel types (gas/liquid/solid). Compliance is expected with the boilers use of ultra-low-NOx burners and the emergency generator and fire pump engines being Tier compliant engines. The boilers are not subject to sections (a) or (b).

Rule 475-Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants of 11 lbs/hr or 0.01 gram/standard cubic foot. Compliance is achieved if either the mass limit or the concentration limit is met. Mass PM10 emissions from the boiler are estimated at 1.245 lbs/hr, and 0.0034 gram/standard cubic foot during natural gas firing at maximum firing load. Therefore, compliance is expected. ~~Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS.~~

Regulation IX – Standards of Performance for New Stationary Sources

Rule 900 – Standard of Performance for New Stationary Source (NSPS)

~~**This rule incorporates the Federal NSPS (40 CFR 60) rules by reference. The proposed boilers are subject to subpart Dc. Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS. Regulation IX – Standards of Performance for New Stationary Sources**~~

This rule incorporates the Federal NSPS (40 CFR 60) rules by reference. The proposed boilers are subject to subpart Db, and Dc. The District conditions would ensure compliance with the requirements of this rule.

Regulation XI – Source Specific Standards

Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

~~The purpose of this rule is to reduce NOx, VOCs, and CO emissions from engines with 50 hp or higher.~~ The purpose of Rule 1110.2 is to reduce NOx, VOC, and CO from internal combustion engines. The diesel emergency engines proposed for this project are low-usage engines which would each operate less than 200 hours per year and which would be used for firefighting and emergency electrical generation purposes only, and are therefore exempt from the requirements of this rule per section (i)(2). Elapsed operating time meters would be installed and maintained on each engine to substantiate compliance. ~~Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS.~~

~~Rule 1121 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators and Process Heaters~~

~~Rule 1121 limits NOx emissions from natural gas fired residential type water heaters. Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS.~~

Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators and Process Heaters

~~Rule 1146 limits NOx emissions from boilers, steam generators, and process heaters with greater than 5 MMBtu/hr rated input capacity used in industrial, institutional, and commercial operations. Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS. In a letter to the project owner dated April 26, 2013, the SCAQMD indicated that the project owner's initial proposal to limit NOx emissions from their auxiliary boilers to 9 ppmv was inadequate and that no more than 5 ppmv would be allowed. This requirement became effective January 1, 2013.~~ The purpose of this rule is to limit NOx emissions from boilers, steam generators, and process heaters of greater than 5 MMBtu per hour rated input capacity used in industrial, institutional, and commercial operations with several listed exceptions. The rule specifies NOx limits and CO compliance plans for boilers, steam generators, and process heaters by size process function. The boilers would burn natural gas exclusively and would comply with CO BACT (applicant proposes 25 ppmv for each boiler) which is less than the 400 ppm CO limits in this rule. The applicant is proposing 5 ppmv NOx for the auxiliary boilers and 9 ppmv NOx for the night time preservation boilers, the applicant proposes to opt-in to RECLAIM. Compliance is expected.

~~Rule 1166 – Volatile Organic Compound Emissions from Decontamination of Soil~~

~~This rule specifies requirements for VOC emissions from the handling and decontamination activities of VOC-contaminated soils. Operational impacts will be discussed in the Final Staff Assessment (FSA) once SCAQMD finalizes the Determination of Compliance for PSEGS.~~

Regulation XIII – New Source Review

Rule 1303 – Requirements

Rule 1303 (~~b)(1~~a) – BACT: The District ~~This rule~~ requires implementation of BACT for a new emissions unit. Each of PSEGS's ~~construction related equipment~~ major units would employ current BACT~~.~~ for any new source which results in an emission increase of any non-attainment air contaminant, any ozone depleting compound, or ammonia. PSEGS is a new source with a potential for an increase in emissions and therefore, BACT is required. PSEGS is expected to comply with the current minor source BACT requirements.

Rule 1303 (b)(2) – Offsets: The District analyzed NOx emissions and determined they are greater than the 4 ton per year exemption thresholds. Therefore, the NOx emissions are required to be offset in accordance with Rule 1303(b)(2). The applicant submitted a written request on July 12, 2013 to opt into the NOx RECLAIM program to mitigate NOx emissions, thus NOx ERC's are not required. The VOC, SOx and PM10 emissions has a Facility Exemption from Rule 1303 (b)(2) per Rule 1304 (d)(1)(A). In addition, the non-RECLAIM pollutants for the emergency internal combustion engines are exempt from offsets under SCAQMD Rule 1304(a)(4). Compliance is expected.

Rule 1303 (b)(1) – Modeling: ~~Construction m~~ The applicant must substantiate with modeling that the new facility would not cause a violation, or make significantly worse an existing violation according to Appendix A of Rule 1303, or other analysis approved by the SCAQMD Executive Officer or designee, of any state or national ambient air quality standard at any receptor location in the District. If emissions from the individual permit units are greater than the amounts in the table A-1 of Rule 1303, then modeling is required.

Staff's review of the modeling analysis concluded that the applicant used the appropriate EPA approved AERMOD model along with the appropriate model options in the analysis. Therefore compliance with modeling requirements is expected. The two auxiliary boilers comply with the limits listed in Table A-2, of Rule 1303 thus compliance with this rule is met.

Regulation XXXI – Acid Rain Permit Program

Subpart A through I – Provisions

The PSEGS facility is subject to the requirements of the federal Acid Rain program. EPA reviewed 72.6(b)(4)(ii) to determine if the auxiliary boilers met the definition of cogeneration. EPA determined the boilers did not meet the definition of cogeneration and the full provision of the acid rain regulation applies. The program is similar in concept to RECLAIM in that facilities are required to cover SO_2 emissions with SO_2 allowances; analogous to NOx RTCs. PSEGS is expected to comply with this regulation. ~~odeling is required if emissions of NOx, CO, and PM10 exceed the emission rates specified in Appendix A, Table A-1 of this rule. The emissions for PSEGS have not been determined to exceed these thresholds; therefore, modeling requirements do not apply.~~

NOTEWORTHY PUBLIC BENEFITS

Renewable energy facilities, such as PSEGS, are needed to meet California's mandated renewable energy goals. While there are no local area air quality public benefits[12] resulting from the proposed modified project, it would indirectly reduce criteria pollutant emissions within the Western U.S., and part of Canada and Mexico by reducing fossil fuel–fired electricity generation.

RESPONSE TO ~~AGENCY AND PUBLIC~~ COMMENTS

PALEN SOLAR HOLDING'S FINAL COMMENTS ON THE PSA (PALEN 2013PP)

Palen Solar Holdings included a comment on the PSA. The AQ comment is responded to below.

Modification to AQ-SC5 language (TN 200077)

Response: Staff has reviewed the language change to Condition of Certification **AQ-SC5** that was suggested by the applicant, submitted on July 29, 2013. Staff has accepted most of the requested modifications to Condition of Certification **AQ-SC5**. The changes are reflected in the Air Quality Condition of Certification.

INTERVENOR BASIN AND RANGE WATCH'S STATUS REPORT (BRW 2013A)

The Basin and Range Watch group included comments regarding background ambient pollutant concentrations. Each of these comments is responded to separately below.

Fugitive Dust During Construction ~~In Regards To~~ And Valley Fever Concerns

The Intervenor ~~has~~ raised concerns in their (May 8, 2013) status report and email (May 1, 2013) regarding air quality and public health during the construction and operational phases of the proposed project to insure air quality standards don't exceed significant thresholds of PM10/PM2.5 for fugitive and windblown dust.

Response: Ambient air quality standards are set at levels that are protective of public health and welfare. Energy Commission air quality staff are responsible for evaluating the compliance of proposed emitting sources with ambient air quality standards, which are adopted for the purpose of protecting public health, among other matters. However, Valley Fever is not specifically addressed under ambient air quality standards. For specific responses to Basin and Range Watch's concerns regarding Valley Fever relating to public health, please see the Public Health and Worker Safety sections of this ~~PSA~~FSA. The ambient air quality impact assessment submitted for the PSEGS project during construction and operation would demonstrate project impacts would be below the most stringent state and federal ambient air quality standards when combined with the proposed mitigation measures as required in Air Quality Conditions of Certification **AQ-SC1** to **AQ-SC5**.

[12] Air quality benefits should not be confused with greenhouse gas/climate change benefits, which are discussed in Appendix AIR-1.

NOx Formation On The Receiver's Surface

The Intervenor raised concerns in their (October 22, 2013) Prehearing Conference statement regarding NOx formation on the superheated receiver surface.

> **Response**: The steam generated in the solar receiver would reach approximately 1,050 degrees F and the receiver's surface temperature needs to be only marginally above this temperature. NOx emissions do not form in significant amounts until temperatures reach 2,800 F. If receiver surface temperatures are held down to below about 1,400F, the thermal NOx formation would be negligible[13]

COMMENTOR TOURISM ECONOMICS COMMISSION/MORONGO BASIN CONSERVATION ASSOCIATION (TEC 2013A)

The Tourism Economics Commission/Morongo Basin Conservation Association included comments regarding background ambient pollutant concentrations. Each of these comments is responded to separately below.

Air Quality And Greenhouse Gas LORS Compliance (TN 200074)

The Intervenor raised concerns in their (July 29, 2013) letter stating "Compliance with LORS, Mitigation, and Additional Information needs to include a science based analysis of greenhouse gas emissions from construction, maintenance, transmission activities, potential decommissioning of the facility, and the diversion of traffic to other routes (including Hwy 62) due to the adverse impacts of the facility on the I-10 scenic and business transportation corridor."

> **Response**: The PSEGS project would comply with all LORS, and would not cause a new ambient air quality standards exceedance once fully mitigated. Energy Commission air quality staff are responsible for evaluating the compliance of proposed emitting sources with ambient air quality standards, which are adopted for the purpose of protecting public health, among other matters. The ambient air quality impact assessment submitted for the PSEGS project during construction and operation demonstrate project impacts would be below the most stringent state standards with the proposed mitigation measures during construction as required in Air Quality Conditions of Certification **AQ-SC1** to **AQ-SC5**, and operations as required by Air Quality Conditions of Certification **AQ-SC6 to AQ-SC10 and Conditions of Certification AQ-1 to AQ-60.** For impacts directly related to traffic and other routes, please see the **Traffic and Transportation** section of this FSA. Traffic diversion incremental emissions have not been determined. Emissions may actually decrease or increase slightly. Greenhouse gas emissions are evaluated in **Appendix Air-1-Greenhouse Gas Emissions**.

AGENCY DEPARTMENT OF TRANSPORATION DISTRICT 8 PLANNING (DOT 2013A)

The Department of Transportation District 8 raised concerns in their (dated August 12, 2013) docketed letter (TN 200198). Their concerns are not summarized below (see docketed letter), but each concern responded to separately below.

[13] http://www.epa.gov/ttncatc1/dir1/fnoxdoc.pdf

Dust Control During Construction Activities And Wind Erosion Control Techniques

Response: Energy Commission staff recommends the PSEGS project be required to comply with Conditions of Certification **AQ-SC1** to **AQ-SC4** to minimize dust and to prevent dust from leaving the project's boundary and creating poor visibility conditions along the state highway. Conditions of Certification **AQ-SC3** and **AQ-SC4** require the use of water or chemical dust suppressants to control any dust plume, and have a dust plume response plan to minimize fugitive dust.

Vehicles on unpaved areas to the Construction Site

Response: Energy Commission staff recommends the PSEGS project be required to comply with revised Condition of Certification **AQ-SC3(c),** to minimize and prevent dust emissions from construction activities on unpaved roads with a requirement of not exceeding speeds of 10 mph.

Prevention of dust track-out to Corn Springs Interchange should be prevented.

Response: Energy Commission staff recommends the PSEGS project be required to comply with revised Condition of Certification **AQ-SC3** to minimize track-out on all construction equipment. Track-out is to be minimized by inspecting, washing as necessary, and clearing tires so they are free of dirt prior to entering paved roadways, and adding gravel ramps of at least 20 feet in length at the tire washing/cleaning station. Additionally, all unpaved exits from the construction site are to be graveled or treated to prevent track-out to public roadways.

MITIGATION MEASURES/ PROPOSED CONDITIONS OF CERTIFICATION

Staff recommends the following Air Quality Conditions of Certification for PSEGS:

Staff makes the following conclusions and recommendations to mitigate PSEGS impacts:

- ~~If left unmitigated, the proposed modified project's construction activities would likely contribute to significant CEQA-significant adverse PM10 and ozone impacts. Therefore, staff recommends **AQ-SC1** to **AQ-SC5** to mitigate these potential impacts.~~
- ~~**AQ-SC5** was modified to match a more revised version of the condition that is similar to the more recent solar projects that have been approved by the Energy Commission or are pending projects.~~
- ~~**AQ-SC6** to **AQ-SC11** are included below but have not been modified and will be evaluated in the FSA to determine if they are necessary for facility operations.~~ The proposed modified project would comply with applicable district rules and regulations and staff recommends the inclusion of the District's PDOC conditions as Conditions of Certification **AQ-1** through **AQ-60.**

- If left unmitigated, the proposed modified project's construction activities would likely contribute to significant CEQA adverse PM10 and ozone impacts. Staff recommends Conditions of Certification **AQ-SC1** to **AQ-SC5** to mitigate the potential impacts.
- The proposed modified project's operation would not cause new violations of any NO_2, SO_2, PM2.5 or CO ambient air quality standards. Therefore, the project-direct operation NOx, SOx, PM2.5 and CO emission impacts are not CEQA significant.
- The proposed modified project's direct and indirect, or secondary emissions contribution to existing violations of the ozone and PM10 ambient air quality standards are likely CEQA significant if unmitigated. Therefore, staff recommends Condition of Certification **AQ-SC6** to mitigate the onsite maintenance vehicle emissions and Condition of Certification **AQ-SC7** to mitigate the operating fugitive dust emissions to ensure that the potential ozone and PM10 CEQA impacts are mitigated to less than significant over the life of the project.
- The HTF system has been removed as part of the new modified project, and therefore the project will no longer have excess VOC emissions. Staff recommends deletion of Condition of Certification **AQ-SC9** because ERCs have been determined to no longer be necessary as part of the mitigation measures.
- Condition of Certification **AQ-SC9** has been replaced to require quarterly submittals of documents to show the project is maintaining compliance with all Conditions of Certification that are required.
- To ensure that the two cooling tower emissions are adequately controlled through the use of a high efficiency mist eliminator and control of the recirculating water total dissolved solids content, staff recommends Condition of Certification **AQ-SC10**.
- ~~To ensure that the project alternatives, if any one of them is approved, do not create significant short term~~ ~~NO_2~~ ~~impacts staff has recommended Condition of Certification **AQ-SC11** that is only applicable to the project alternatives,~~
- The proposed modified project would be consistent with the requirements of SB 1368 and the Emission Performance Standard for greenhouse gases (see **Appendix Air-1 Greenhouse Gas Emissions**).

Staff has proposed modifications to the Air Quality Conditions of Certification as shown below. (Note: Deleted text is in ~~strikethrough~~; new text is **bold and underlined.**)

CONDITIONS OF CERTIFICATION

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4** and **AQ-SC5** for the entire project site and linear facility construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM Delegates. The AQCMM and AQCMM Delegates shall have full access to all areas of construction on the project site and linear facilities, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation Conditions. The AQCMM and AQCMM Delegates may have other responsibilities in addition to those described in this Condition. The AQCMM shall not be terminated without written consent of the Compliance Project Manager (CPM).

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval, the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM Delegates.

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4,** and **AQ-SC5**.

Verification: At least 30 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The AQCMP shall include effectiveness and environmental data for the proposed soil stabilizer. The CPM will notify the project owner of any necessary modifications to the plan within 15 days from the date of receipt.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report that demonstrates compliance with the Air Quality Construction Mitigation Plan (AQCMP) mitigation measures for the purposes of minimizing fugitive dust emission creation from construction activities and preventing all fugitive dust plumes that would not comply with the performance standards identified in **AQ-SC4** from leaving the project site. **The definition of stabilized surface for the purposes of fugitive dust control means to control fugitive dust by means of using a soil binding agent or other effective means to suppress fugitive dust and keep it from leaving the project boundaries and not causing/creating fugitive dust plumes that would leave the project site.** The following fugitive dust mitigation measures shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**, and any deviation from the AQCMP mitigation measures shall require prior CPM notification and approval.

a. The main access roads through the facility to the power block areas will be either paved or stabilized using soil binders, or equivalent methods, to provide a stabilized surface that is similar for the purposes of dust control to paving, that may or may not include a crushed rock (gravel or similar material with fines removed) top layer, prior to initiating construction in the main power block area, and delivery areas for operations materials (chemicals, replacement parts, etc.) will be paved or treated prior to taking initial deliveries.

b. All unpaved construction roads and unpaved operation and maintenance site roads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as ARB approved soil stabilizers, and shall not increase any other environmental impacts, including loss of vegetation to areas beyond where the soil stabilizers are being applied for dust control. All other disturbed areas in the project and linear construction sites shall be watered as frequently as necessary during grading (consistent with **Biology** Conditions of Certification **BIO-8** that address the minimization of standing water); and after active construction activities shall be stabilized with a non-toxic soil stabilizer or soil weighting agent, or alternative approved soil stabilizing methods, in order to comply with the dust mitigation objectives of Condition of Certification **AQ-SC4**. The frequency of watering can be reduced or eliminated during periods of precipitation.

c. No vehicle shall exceed 10 miles per hour on unpaved areas within the construction site, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

d. Visible speed limit signs shall be posted at the construction site entrances.

e. All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

f. Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

g. All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

h. All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

i. Construction areas adjacent to any paved roadway below the grade of the surrounding construction area or otherwise directly impacted by sediment from site drainage shall be provided with sandbags or other equivalently effective measures to prevent run-off to roadways, or other similar run-off control measures as specified in the Storm Water Pollution Prevention Plan (SWPPP), only when such SWPPP measures are necessary so that this Condition does not conflict with the requirements of the SWPPP.

j. All paved roads within the construction site shall be swept daily or as needed (less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

k. At least the first 500 feet of any paved public roadway exiting the construction site or exiting other unpaved roads en route from the construction site or construction staging areas shall be swept as needed (less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff resulting from the construction site activities is visible on the public paved roadways.

l. All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or shall be treated with appropriate dust suppressant compounds.

m. All vehicles that are used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.

n. Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this Condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

Verification: The AQCMM shall provide the CPM a Monthly Compliance Report to include the following to demonstrate control of fugitive dust emissions:

A. a summary of all actions taken to maintain compliance with this Condition;

B. copies of any complaints filed with the District in relation to project construction; and

C. any other documentation deemed necessary by the CPM or AQCMM to verify compliance with this Condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 Dust Plume Response Requirement: The AQCMM or an AQCMM Delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported (A) off the project site and within 400 feet upwind of any regularly occupied structures not owned by the project owner or (B) 200 feet beyond the centerline of the construction of linear facilities indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified. The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed:

Step 1: The AQCMM or Delegate shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

Step 2: The AQCMM or Delegate shall direct implementation of additional methods of dust suppression if Step 1, specified above, fails to result in adequate mitigation within 30 minutes of the original determination.

Step 3: The AQCMM or Delegate shall direct a temporary shutdown of the activity causing the emissions if Step 2, specified above, fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or

Delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or Delegate to shut down an activity, if the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMM shall provide the CPM a Monthly Compliance Report **(MCR)** to include:

A. a summary of all actions taken to maintain compliance with this Condition;

B. copies of any complaints filed with the District in relation to project construction; and

C. any other documentation deemed necessary by the CPM or AQCMM to verify compliance with this Condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC5 Diesel-Fueled Engine Control: The AQCMM shall submit to the CPM, in the ~~Monthly Compliance Report~~ **MCR**, a ~~construction mitigation report~~ **table** that demonstrates compliance with the AQCMP mitigation measures for purposes of controlling diesel construction-related **combustion** emissions. ~~The following off road diesel construction equipment mitigation measures shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by AQ-SC2, and~~ **A**ny deviation from the AQCMP mitigation measures ~~shall require~~ **requires** prior CPM notification and approval.

All ~~diesel fueled engines~~ **off-road diesel construction equipment with a rating of 50 hp or greater** used in the construction of ~~the~~ this facility shall ~~have clearly visible tags issued~~ **be powered** by the ~~onsite AQCMM showing that the engine meets the Conditions set forth herein.~~ **cleanest engines reasonably and locally available that also comply with the** California ~~Emissions Standards~~ **Air Resources Board's (ARB's) Regulation** for **In-Use** Off-Road ~~Compression Ignition Engines, as specified in~~ **Diesel Fleets** (California Code of Regulations Title 13, ~~section 2423(b)(1), unless a good faith effort to~~ **Article 4.8, Chapter 9, Section 2449 et. Seq.) and shall be included in** the ~~satisfaction of~~ **Air Quality Construction Mitigation Plan (AQCMP) required by AQ-SC2. The AQCMP measures shall include** the ~~CPM that is certified by~~ following, with the ~~onsite AQCMM demonstrated that such~~ lowest-emitting engine ~~is not~~ **chosen in each case, as** available:

a. All off-road vehicles with compression ignition engines shall comply with the California Air Resources Board's (ARB's) Regulation for ~~a particular item of equipment. In the event that a Tier 3 engine is not~~ **In-Use Off-Road Diesel Fleets**.

b. To meet the highest level of emissions reduction available for ~~and off-road~~ **the engine family of the equipment** ~~larger than 100 hp, that,~~ **each piece of diesel-powered equipment shall be powered by a Tier 4 engine (without add-on controls) or Tier 4i engine (without add-on controls), or a Tier 3 engine with a post-combustion retrofit device verified for**

<u>use on the particular engine powering the device by the ARB or the US EPA. For PM, the retrofit device shall be a particulate filter if verified, or a flow-through filter, or at least an oxidation catalyst. For NOx, the device shall meet the latest Mark level verified to be available (as of January 2012, none meet this NOx requirement).</u>

c. For diesel powered equipment where the requirements of Part “b” cannot be met, the equipment shall be equipped with a Tier **<u>3 engine without retrofit control devices or with a Tier</u>** 2 **<u>or lower Tier</u>** engine ~~or an engine that is equipped with~~ **<u>using</u>** retrofit controls **<u>verified by ARB or US EPA as the best available control device</u>** to reduce exhaust emissions of **<u>PM or</u>** nitrogen oxides (NOx)~~and diesel particulate matter (DPM) to no more than Tier 2 levels~~ unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices ~~is~~ **<u>can be considered</u>** “not practical” for the following, as well as other, reasons:

1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. Environmental Protection Agency to control the engine in question ~~to Tier 2 equivalent emission levels~~ and the highest level of available control using retrofit or Tier 1 engines is being used for the engine in question; or

2. **<u>The use of the retrofit device would unduly restrict the vision of the operator such that the vehicle would be unsafe to operate because the device would impair the operator’s vision to the front, sides, or rear of the vehicle, or</u>**

3. The construction equipment is intended to be on site for 10 **<u>work</u>** days or less.

d. The CPM may grant relief from ~~this~~ **<u>a</u>** requirement **<u>in Part “b” or “c”</u>** if the AQCMM can demonstrate a good faith effort to comply with ~~this~~ **<u>the</u>** requirement and that compliance is not practical.

e. The use of a retrofit control device may be terminated immediately provided that**<u>: (1)</u>** the CPM is informed within 10 working days ~~of the~~ **<u>following such</u>** termination ~~and that~~**<u>; (2)</u>** a replacement for the **<u>construction</u>** equipment ~~item~~ in question ~~meeting~~**<u>, which meets</u>** the ~~controls~~ **<u>level of control</u>** required ~~in item “b”~~, occurs within 10 **<u>work</u>** days ~~of~~ **<u>following such</u>** termination of the use **<u>(</u>**if the equipment would be needed to continue working at this site for more than 15 **<u>work</u>** days after the use of the retrofit control device is terminated**<u>); and (3)</u>** one of the following **<u>conditions</u>** exists:

1. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive increase in **<u>exhaust</u>** back pressure.

2. The retrofit control device is causing or is reasonably expected to cause engine damage.

3. The retrofit control device is causing or is reasonably expected to cause a substantial risk to workers or the public.

4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.

f. ~~d.~~ All ~~heavy earth moving~~ equipment ~~and heavy duty construction related trucks~~ with engines meeting the requirements ~~of (b)~~ above shall be properly maintained and the engines tuned to the engine manufacturer's specifications. **Each engine shall be in its original configuration and the equipment or engine must be replaced if it exceeds the manufacturer's approved oil consumption rate.**

g. ~~e. All diesel heavy construction equipment shall not idle for more than five minutes. Vehicles that need to idle as part of their normal operation (such as concrete trucks) are exempted from this requirement.~~ Construction equipment will employ electric motors when feasible.

h. **All off-road diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein**.

Verification: The AQCMM shall include in the ~~Monthly Compliance Report~~ **MCR** the following to demonstrate control of diesel construction-related emissions:

A. A summary of all actions taken to control diesel construction related emissions;

B. **A table listing** ~~list of~~ all heavy equipment used on site during that month, ~~including~~ **showing the tier level of each engine and the basis for alternative compliance with this condition for each engine not meeting Part "b" requirements. The MCR shall identify** the owner of ~~that~~ **the** equipment and **contain** a letter from each owner indicating that **the** equipment has been properly maintained; and

C. Any other documentation deemed necessary by the CPM and ~~the~~ AQCMM to verify compliance with this ~~Condition. Such information may be provided via electronic format or disk at the project owner's discretion~~ **condition**.

AQ-SC6 The project owner, when obtaining dedicated on-road or off-road vehicles for mirror washing activities and other facility maintenance activities, shall only obtain vehicles that meet California on-road vehicle emission standards or appropriate U.S.EPA/California off-road engine emission standards for the latest model year available when obtained.

Verification: At least 30 days prior to the start of commercial operation, the project owner shall submit to the CPM a copy of the plan that identifies the size and type of the on-site vehicle and equipment fleet and the vehicle and equipment purchase orders and contracts and or purchase schedule. The plan shall be updated every other year **for any vehicles obtained since the previous report and the updated plan shall be** ~~and~~ submitted in the Annual Compliance Report.

AQ-SC7 The project owner shall provide a site Operations Dust Control Plan, including all applicable fugitive dust control measures identified in the verification of **AQ-SC3** that would be applicable to minimizing fugitive dust emission creation from operation and maintenance activities and preventing all fugitive dust plumes that would not comply with the performance standards identified in **AQ-SC4** from leaving the project site; that:

a. describes the active operations and wind erosion control techniques such as windbreaks and chemical dust suppressants, including their ongoing maintenance procedures, that shall be used on areas that could be disturbed by vehicles or wind anywhere within the project boundaries; and

b. identifies the location of signs throughout the facility that will limit traveling on unpaved portion of roadways to solar equipment maintenance vehicles only. In addition, vehicle speed shall be limited to no more than 10 miles per hour on these unpaved roadways, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

The site operations fugitive dust control plan shall include the use of durable non-toxic soil stabilizers on all regularly used unpaved roads and disturbed off-road areas, or alternative methods for stabilizing disturbed off-road areas, within the project boundaries, and shall include the inspection and maintenance procedures that will be undertaken to ensure that the unpaved roads remain stabilized. The soil stabilizer used shall be a non-toxic soil stabilizer or soil weighting agent that can be determined to be as efficient as or more efficient for fugitive dust control than ARB approved soil stabilizers, and that shall not increase any other environmental impacts including loss of vegetation to areas beyond where the soil stabilizers are being applied for dust control.

~~The performance and application of the fugitive dust controls shall also be measured against and meet the performance requirements of Condition **AQ-SC4**.~~ The measures and performance requirements of **AQ-SC4** shall also be included in the operations dust control plan.

<u>**Verification**</u>: At least 30 days prior to start of commercial operation, the project owner shall submit to the CPM for review and approval a copy of the site Operations Dust Control Plan that identifies the dust and erosion control procedures, including effectiveness and environmental data for the proposed soil stabilizer, that will be used during operation of the project and that identifies all locations of the speed limit signs. Within 60 days after commercial operation, the project owner shall provide to the CPM a report identifying the locations of all speed limit signs, and a copy of the project employee and contractor training manual that clearly identifies that project employees and contractors are required to comply with the dust and erosion control procedures and on-site speed limits.

AQ-SC8 The project owner shall provide the CPM copies of all District issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) documents for the facility.

The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project federal air permit.

The project owner shall submit to the CPM any modification to any federal air permit proposed by the District or U.S. Environmental Protection Agency (U.S. EPA), and any revised federal air permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any ATC, PTO, and proposed federal air permit modifications to the CPM within 5 working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified ATC/PTO documents and all federal air permits to the CPM within 15 days of receipt.

AQ-SC9 **The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter, that include operational and emissions information as necessary to demonstrate compliance with the conditions of certification herein. The Quarterly Operation Report will specifically note or highlight any incidences of noncompliance.**

Verification: The project owner shall submit the Quarterly Operation Reports to the CPM and APCO no later than 30 days following the end of each calendar quarter.

~~AQ-SC9 The project owner shall provide a list of the proposed VOC emission reduction credit (ERC) sources that total at least 68 pounds per day, shall submit requests to modify this list, and shall submit documentation confirming that the ERCs have been surrendered as required by South Coast Air Quality Management District rules.~~

~~Verification: The project owner shall provide to the CPM the following:~~

~~A. The list of proposed emission reduction credit sources, with the amount of reduction, the location of reduction, the method of reduction and date of reduction prior to initiating construction.~~

~~B. Documentation prior to the start of operation that demonstrates the emission reduction credits have been surrendered in a manner and timeframe that complies with district rules.~~

~~C. Any requests to modify the list of emission reduction credits shall be provided no later than at least 30 days prior to their surrender.~~

AQ-SC10 The project owner shall operate the cooling towers with high efficiency mist eliminators and shall determine and report water quality and annual emissions.

Verification: The project owner shall provide the following at least 30 days prior to installation of the cooling tower to the CPM for review and approval:

A. The manufacturer specifications for the cooling tower, that provides the number of cells and design recirculating water flow rate for the two cooling towers.

B. The manufacturer specifications for the mist eliminators that provide a manufacturer guarantee that the mist eliminators will reduce drift to no more than 0.0005 percent of recirculating water flow.

The project owner shall provide the following in the Annual Compliance Reports:

C. The sampling data for the recirculating water TDS concentration, performed at least quarterly, that demonstrates that the annual average TDS concentration was no more than 1,500 milligrams per liter (ppmw).

D. The estimated annual particulate emissions from the cooling tower using the following equation: (annual gallons of water recirculated) x (0.000005 fraction mist) x (average annual TDS concentration in mg/l) / (1,000,000) x (8.34 lbs/gallon).

~~STAFF CONDITION FOR PROJECT ALTERNATIVES~~

~~AQ-SC11 The project owner shall use one of the following four options to assure that the operation of the emergency engines will not cause an exceedance of the state or federal 1-hour NO_2 ambient air quality standards:~~

1) ~~The project owner shall provide an air dispersion modeling analysis that demonstrates to Staff's satisfaction that the currently proposed or officially revised worst-case operating emissions would not have the potential to cause exceedances of the state or federal 1-hour NO_2 ambient air quality standards, or~~

2) ~~The project owner shall procure emergency generator engines that meet ARB Tier 4 standards for NOx emissions (0.5 grams per break horsepower), or~~

3) ~~In the event that Tier 4 engines are not available at the time of engine purchase, the project owner shall; a) provide documentation from engine manufacturers that Tier 4 engines are not available; and b) procure emergency engines that have a NOx emissions guarantee of no more than 2.6 grams per break horsepower, or~~

4) ~~The project owner shall agree to limit the emergency generator engine testing duration to no more than 30 minutes per event and a testing frequency limited to the minimum required by engine manufacturer.~~

~~In no event shall the project owner propose the use of an emergency engine that does not meet the most strict applicable federal or state engine emission limit regulation without a signed waiver from U.S. EPA or ARB as appropriate. The project owner shall justify the date of engine purchase.~~

~~**Verification**:~~ ~~The project owner shall provide to the CPM the air dispersion modeling analysis, if performed, that demonstrates compliance with part 1) of this condition at least 30 days prior to purchasing the emergency engine generators for this project, or shall provide documentation to the CPM at least five days prior to purchasing the engine generators that demonstrates how they would comply with part 2), or part 3), or part 4) of this condition.~~

District Conditions

The SCAQMD has a unique system of structuring and numbering their permit conditions. In order for the reader to avoid confusion between how the SCAQMD numbers their permit conditions and how the Energy Commission staff normally numbers permit conditions, staff prepared the following table to cross reference the conditions in the PDOC with the conditions presented by staff in this analysis.

AIR QUALITY Table 12
Energy Commission Conditions of Certification and SCAQMD Permit Conditions

Energy Commission Condition of Certification	**SCAQMD Permit Condition**	**Condition Description**
The following conditions of certification apply to the entire facility:		
AQ-1	F9.1	Restricts discharge of visual contaminants into the atmosphere
AQ-2	F14.1	Restricts sulfur content of diesel fuel to n more than 15 ppm by weight
AQ-3	F10.1	Restricts H_2S content of natural gas to no more than 0.075 grains per 100 scf
AQ-4	K67.6	Requires record keeping for architectural coating materials
AQ-5	E193.1	Requires equipment to be operated as required by Energy Commission Conditions of Certification
The following conditions of certification apply to each auxiliary and nighttime preservation boiler:		
AQ-6	D12.1	Requires flow meters on each boiler
AQ-7	H23.1	Requires source testing and reporting for CO
The following conditions apply individually to each auxiliary boiler:		
AQ-8	A63.1	Limits PM10, CO, SOx and VOC emissions during normal operations
AQ-9	A99.1	Exempts NOx emissions limit during commissioning, start-ups and trips
AQ-10	A99.2	Exempts CO emissions limit during commissioning, start-ups and trips
AQ-11	A99.3	Limits NOx emissions to 11.55 lbs/MMCF during interim period (no more than 12 months)
AQ-12	A99.4	Limits NOx emissions to 6.53 lbs/MMCF after interim period
AQ-13	A195.1	Limits CO to 25 ppmv, dry, averaged over 15 minutes
AQ-14	A195.2	Limits NOx to 5 ppmv, dry, averaged over 15 minutes
AQ-15	A195.4	Limits NOx to 80 ppmv, 30 day rolling average during start-up, shut-down or malfunction
AQ-16	A195.6	Limits NH_3 to 5 ppmv at 3% O_2 dry, averaged over 60 minutes
AQ-17	A327.1	Limits contaminant emissions by concentration or mass, but not both at same time
AQ-18	A433.1, A433.2	Limits NOx emissions to 5 ppmv; limits start-ups to 3.5 lbs/hr per cold or very cold start; limits cold starts as follows: no more than 10.5 lbs, 10/year and duration not to exceed 180 minutes; limits very cold starts as follows: no more than 15.7 lbs, 5/year and duration not to exceed 270 minutes

AIR QUALITY Table 12
Energy Commission Conditions of Certification and SCAQMD Permit Conditions

Energy Commission Condition of Certification	SCAQMD Permit Condition	Condition Description
AQ-19	C1.1, C1.2	Limits each boiler to no more fuel use than 40 mmcf per calendar month for normal operation and 4.28 mmcf per calendar month during commissioning
AQ-20	C1.3, C1.4	Limits each boiler to no more fuel use than 307 mmcf per year during any non-commissioning year and 311 mmcf per year during commissioning year
AQ-21	D12.3	Requires flow meter to measure hourly ammonia use
AQ-22	D12.4	Requires temperature gauge to measure temperature at SCR inlet
AQ-23	D12.5	Requires pressure gauge to measure differential pressure across SCR
AQ-24	D29.1	Requires source testing for NOx, CO, SOx, PM and NH_3
AQ-25	D29.2	Requires additional source testing for NH_3
AQ-26	D82.1	Requires CEMS for CO emissions
AQ-27	D82.2	Requires CEMS for NOx emissions
AQ-28	E179.1	Defines the term "continuously recording" as hourly for ammonia and SCR temperature
AQ-29	E179.2	Defines the term "continuously recording" as once per month for SCR pressure
AQ-30	E448.1	Requires full operation of flue gas recirculation system
AQ-31	E448.4	Defines record keeping requirements
AQ-32	E448.5	Requires SCR to operate once SCR reactor inlet reaches 550 °F
AQ-33	H23.3	Defines 40 CFR 60 Subpart Db as applying to PM, SOx and NOx
AQ-34	I298.1, I298.2	Requires project owner to hold 5714 pounds of NOx reclaim credits for each boiler
AQ-35	K67.1	Requires project owner to keep monthly fuel use records for 5 years as approved by SCAQMD Executive Officer
AQ-36	K67.2	Requires project owner to keep fuel use records during certification, commissioning, and prior to CEMS certification
The following conditions apply individual to each nighttime preservation boiler:		
AQ-37	A63.2	Limits PM10, CO, SOx and VOC emissions during normal operations
AQ-38	A195.3	Limits NOx to 9 ppmv, dry, averaged over 15 minutes
AQ-39	C1.5	Limits each boiler to no more fuel use than 4.34 mmcf per calendar month for normal operation
AQ-40	C1.6	Limits each boiler to no more fuel use than 0.11 mmcf in any one commissioning period
AQ-41	C1.7	Limits each boiler to no more fuel use than 48 mmcf in any one calendar year

AIR QUALITY Table 12
Energy Commission Conditions of Certification and SCAQMD Permit Conditions

Energy Commission Condition of Certification	SCAQMD Permit Condition	Condition Description
AQ-42	D29.3	Requires source testing for NOx, CO, SOx, and PM
AQ-43	D29.4	Requires additional source test for NOx once every 5 years
AQ-44	H23.4	Defines 40 CFR 60 Subpart Dcas applying to PM and SOx
AQ-45	I298.3, I298.4	Requires project owner to hold 565 pounds of NOx reclaim credits for each boiler
AQ-46	K67.5	Requires project owner to keep fuel usage records for 5 years as approved by SCAQMD Executive Officer
The following conditions apply to each diesel-fueled internal combustion engine used to power each emergency generator or fire pump:		
AQ-47	B61.2	Limits diesel fuel to no more than 15 ppm by weight
AQ-48	C1.8	Limits engine operation to no more than 200 hours in any one year
AQ-49	C1.10	Limits engine operation to no more than 4.2 hours in any one month, inclusive of maintenance and testing
AQ-50	D12.2	Requires non-resettable engine time meter
AQ-51	E448.2	Requires engines to comply with 40 CFR 60.4205(B)
AQ-52	E448.3	Requires engines to be operated and maintained according to manufacturer instructions and meet 40CFR89, 94, and 1068 as applicable
AQ-53	H23.5	Defines District Rule 1470 applicable for PM and 431.2 applicable for Sulfur
AQ-54	K67.3	Requires project owner to keep operating log records for engine
AQ-55	K67.4	Requires project owner to keep annual operating log records for 3 years
The following conditions apply individually to each diesel-fueled internal combustion engine used to power an emergency generator:		
AQ-56	C1.11	Limits engine operating time to no more than 30 minutes in any one day
The following conditions apply individually to each 3633 BHP diesel-fueled internal combustion engine used to power an emergency generator:		
AQ-57	I298.5, I298.6	Requires project owner to hold 5922 pounds of NOx reclaim credits for each engine
The following conditions apply individually to each 398 BHP diesel-fueled internal combustion engine used to power an emergency generator:		
AQ-58	I298.7	Requires project owner to hold 434 pounds of NOx reclaim credits for each engine
The following conditions apply individually to each 617 BHP diesel-fueled internal combustion engine used to power emergency fire pumps:		
AQ-59	C1.12	Limits engine operation to no more than 50 hours in any

AIR QUALITY Table 12
Energy Commission Conditions of Certification and SCAQMD Permit Conditions

Energy Commission Condition of Certification	SCAQMD Permit Condition	Condition Description
		one year
AQ-60	I298.8, I298.9, I298.10	Requires project owner to hold 707 pounds of NOx reclaim credits for each engine

The following conditions of certification derive from the SCAQMD's Preliminary Determination of Compliance dated October 18, 2013. If there are changes made in the Final Determination of Compliance, the conditions below will be revised with an addendum or by other means.

The following conditions apply to entire project:

AQ-1 Except for open abrasive blasting operations, the project owner shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated No.1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or

(b) Of such opacity as to obscure an observer' s view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.

[RULE 401, 3-2-1984; RULE 401, 11-09-2001]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-2 The project owner shall only use diesel fuel containing the following specified compounds:

COMPOUND	Range	PPM BY WEIGHT
Sulfur	Less than or equal to	15

The project owner shall maintain a copy of the MSDS on site

[Rule 431.2]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-3 The project owner shall not use natural gas containing the following specified compounds:

Compound	Grains per 100 scf
H2S	Greater than 0.750

This concentration limit is an annual average based on monthly sample of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H2S.

[Rule 1303(b) – Offset]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-4 The project owner shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

For architectural applications where thinners, reducers, or other VOC containing materials are added, maintain daily records for each coating consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

[Rule 1113]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-5 The project owner shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 09-AFC-7 project [CEQA]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

The following conditions apply individually to each 249 mmBTU boiler and 10.5 mmBTU nighttime preservation boiler:

AQ-6 The project owner shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the boiler. The project owner shall also install and maintain a device to continuously record the parameter being measured.

[Rule 1303(b)(2) – Offset, Rule 2012,40 CFR 60.48c(g)(2)]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly. As required by other conditions, the project owner shall submit all dates of operation, elapsed time in hours, and the reason for each operation in the Quarterly Operations Report (AQ-SC9).

AQ-7 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
CO	District Rule	1146

The project owner of this equipment shall comply with source testing requirements in subdivision (D)(6)--compliance determination of rule 1146. The project owner of this equipment shall comply with periodic monitoring requirements of rule 1146 (C)(8).

[Rule 1146]; [40CFR 60 SUBPART Dc]

Verification: The project owner shall submit to the CPM the report documenting results of the testing no less than 30 days after producing the report.

The following conditions apply individually to each 249 mmBTU auxiliary boiler (facility total = 2):

AQ-8 The project owner shall limit emission from this equipment as follows:

Contaminant	Emissions Limit
PM10	214 LBS IN ANY ONE MONTH
CO	1451 LBS IN ANY ONE MONTH
SOx	85 LBS IN ANY ONE MONTH
VOC	173 LBS IN ANY ONE MONTH

The project owner shall calculate the calendar monthly emissions for VOC, PM10 and SOx using the equation below and the following emission factors:

Uncontrolled emission factors: VOC: 5.7 lb/mmcf; PM10: 7.6 lb/mmcf; CO: 157.39 lb/mmcf, and SOx: 2.14 lb/mmcf.

Controlled emission factors: VOC: 4.1 lb/mmcf; PM10: 5.1 lb/mmcf; CO: 19.87 lb/mmcf and SOx: 2.14 lb/mmcf.

The uncontrolled emissions factors are to be used during start-up when the boiler is operating at 17.5% load or less

Monthly Emissions, lb/month = X (E.F.)

Where X = monthly fuel usage in mmcf/month and E.F. = emission factor indicated above.

The project owner shall calculate the emission limit(s) for the purpose of determining compliance with the monthly CO limit in the absence of valid CEMS data by using the above equation and the following emission factor(s):

a. During the commissioning period the, 38.85 lbs CO/mmcf emissions factor to be used during low, medium and high loads. During cold start and warm start 153.30 lb/mmcf is to be used.

b. After installation of the CO catalyst but prior to CO CEMS certification testing – 19.87 lb CO/mmcf to be used for all modes of operation, excluding start-up operations, boiler restarts, hot restart/emergency trip, boiler cold and very cold start. 157.4 lb CO/mmcf to be used during boiler morning start-up operations, boiler restarts, hot restart/emergency trip and boiler cold and very cold start.

c. After CO CEMS certification testing – 19.87 lb/CO mmcf is to be used. After CO CEMS certification test is approved by the SCAQMD, the emissions monitored by the CEMS and calculated in accordance with condition 82.1 shall be used to calculate emissions.

The project owner shall provide the SCAQMD with written notification of the date of initial CO catalyst use within seven (7) days of this event.

For the purpose of this condition the boiler shall not commence normal operation until the commissioning process has been completed. The District shall be notified in writing once the commissioning process has been completed. Normal operations may proceed in the same commissioning month provided the project owner follows the requirements listed below.

The project owner shall calculate the commissioning emissions for VOC, SOx and PM10 for the commissioning month (beginning of the month to the last day of commissioning) using the equation below and the following emissions factor;

VOC: 5.7 lb/mmcf;
PM10 5.25 lb/mmcf; and
SOx: 2.14 lb/mmcf.

For Start-up (cold or warm start) the following emission factors shall be used: PM10:10.5 lb/mmcf

Commissioning Emissions, lb/month = X * EF

Where X = commissioning fuel usage in mmcf/month and E.F = emission factor indicated above.

The commissioning emissions for VOC, SOx, CO and PM10 shall be subtracted from the monthly emissions limits (listed in the table a the top of this condition) and the revised monthly emissions limits will be the maximum emissions allowed for the remaining calendar month.

The project owner shall keep records of monthly emissions and the records shall be made available upon request by the SCAQMD Executive Officer.

[Rule 1303 – Offsets]

Verification: The project owner shall submit all emission calculations, fuel use, CEM records and a summary demonstrating compliance of all emission limits stated in this Condition for approval to the CPM on a quarterly basis in the quarterly emissions report (AQ-SC9).

AQ-9 The 5.0 PPM NOx emission limits shall not apply during boiler commissioning, start-ups and emergency trips. The commissioning period shall not exceed 40 total hours. Start-up time shall not exceed the times listed below. Written records of commissioning, start-ups and emergency trips shall be maintained and made available upon request from the SCAQMD Executive Officer.

For this condition a boiler hot/emergency trip start-up is defined as a start-up in which the boiler has been shut down for less than 12 hours. A boiler hot/emergency trip start-up period shall not exceed 45 minutes. For this condition, a boiler warm start-up is defined as a start-up in which the boiler has been shut down for at least 12 hours but less than 36 hours. A boiler warm start-up period shall not exceed 90 minutes.

For this condition a boiler cold start-up is defined as a start-up in which the boiler has been shut down for at least 36 hours but less than 80 hours. A boiler cold start-up period shall not exceed 180 minutes.

For this condition boiler very cold start-up is defined as a start-up in which the boiler has been shut down for at least 80 hours. A boiler very cold start-up period shall not exceed 270 minutes.

[Rule 1703 (a)(2)-PSD BACT, Rule 2005]

Verification: The project owner shall submit a commissioning phase status report monthly as needed, beginning one month from the time of the boiler's first fire. This commissioning status report shall demonstrate compliance with this condition. The monthly commissioning status report shall include criteria pollutant emission estimates for each commissioning activity and total commissioning emission estimates. The monthly commissioning status report shall be submitted to the CPM until the report includes the completion of all commissioning activities. The project owner shall provide the SCAQMD and the CPM with written notification of the initial start-up date no later than 60 days prior to the startup date. During operations, the project operator shall provide maximum daily emissions per minimum time period, start-up and shutdown occurrence, and duration data as part of the Quarterly Operation Report (AQ-SC9) including records of all aborted startups. The project owner shall make the site available for inspection of the commissioning and startup/shutdown records by representatives of the District, ARB and the Commission.

AQ-10 The 25 PPM CO emission limits shall not apply during boiler commissioning, start-ups and emergency trips. The commissioning period shall not exceed 40 total hours. Start-up time shall not exceed the times listed below. Written records of commissioning, start-ups and shall be maintained and made available upon request from the SCAQMD Executive Officer.

For this condition a boiler hot/emergency trip start-up is defined as a start-up in which the boiler has been shut down for less than 12 hours. A boiler hot/emergency trip start-up period shall not exceed 45 minutes.

For this condition, a boiler warm start-up is defined as a start-up in which the boiler has been shut down for at least 12 hours but less than 36 hours. A boiler warm start-up period shall not exceed 90 minutes.

For this condition a boiler cold start is defined as a start-up in which the boiler has been shut down for at least 36 hours but less than 80 hours. A boiler cold start-up period shall not exceed 180 minutes.

For this condition boiler very cold start is defined as a start-up in which the boiler has been shut down for at least 80 hours. A boiler very cold start-up period shall not exceed 270 minutes.

[Rule 1703 (a)(2)-PSD BACT]

Verification: See Verification for AQ-9.

AQ-11 The 11.55 LBS/MMCF NOx emission limits shall only apply during the interim reporting period during initial boiler commissioning to report RECLAIM emissions. During start-up or warm start modes the 92.40 lb/mmcf NOx emissions limits shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.

[Rule 2012 – Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations required by this condition on a quarterly basis as part of the quarterly emissions report of Condition of Certification AQ-SC9.

AQ-12 The 6.53 LBS/MMCF NOx emission limits shall only apply during the interim reporting period after initial boiler commissioning to report RECLAIM emissions. During start-up mode operations with a boiler mode not to exceed 17.5%, the 83.96 lb/mmcf NOx emissions limits shall only apply during the interim reporting period during after initial boiler commissioning to report RECLAIM emissions The interim reporting period shall not exceed 12 months from entry into RECLAIM.

[Rule 2012 – Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

Verification: See Verification for AQ-11.

AQ-13 The 25 PPMV CO emission limit(s) is averaged over 15 minutes at 3 percent O2, dry.

[Rule 1703(a)(2)– PSD-BACT]

Verification: None required.

AQ-14 The 5 PPMV NOX emission limit(s) is averaged over 15 minutes at 3 percent O2, dry.

[Rule 2005, Rule 1703(a)(2)– PSD-BACT]

Verification: None required.

AQ-15 The 80 PPMV NOX emission limit(s) is averaged over 30 day rolling average.

Per §60.44(b)(h), the NOx standards under this section shall apply all times including periods of start-up, shut-down or malfunction.

§60.44(b)(i) Except as provided under paragraph (j) of this section, compliance with the emissions limits under this section is determined on a 30-day rolling average basis.

[40 CFR 60 Subpart Db]

Verification: None required.

AQ-16 The 5 ppmv NH3 emission limit is averaged over 60 minutes at 3% O2, dry basis. The project owner shall calculate and continuously record the NH3 slip concentration using the following:

NH3 (ppmv) = [a–b*c/1EE+06]*1EE+06/b where:

a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at 3% O2)

The project owner shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

The project owner shall use the above described method or another alternative method approved by the SCAQMD Executive Officer.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.

[Rule 1303(a)(1) – BACT]

Verification: The project owner shall include ammonia slip concentrations averaged on an hourly basis calculated via the above protocol and provide the results as part of the Quarterly Operational Report required in Condition of Certification AQ-SC9. Exceedances of the ammonia limit shall be reported as prescribed herein. Chronic exceedances of the ammonia slip limit shall be identified by the project owner and confirmed by the CPM within 60 days of the fourth quarter Quarterly Operational Report (AQ-SC9) being submitted to the CPM. If a chronic exceedance is identified and confirmed, the project owner shall work in conjunction with the CPM to develop a reasonable compliance plan to investigate and redress the chronic exceedance of the ammonia slip limit within 60 days of the above confirmation.

AQ-17 For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.

[Rule 475]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-18 The project owner shall comply at all times with the 5 ppm BACT limit for NOx, except as defined in condition AQ-9 and for the following scenario:

Operating Scenario	Maximum Hourly Emission Limit	Operational Limit
Start-up event	3.5 lb/hr	NOx emissions not to exceed 10.5 lbs total per cold start-up per boiler. The boiler shall be limited to 10 cold start-ups per year, with each start-up not to exceed 180 minutes.

[Rule 1703(a)(2)-PSD-BACT, Rule 2005]

Operating Scenario	Maximum Hourly Emission Limit	Operational Limit
Start-up event	3.5 lb/hr	NOx emissions not to exceed 15.7 lbs total per very cold start-up per boiler. The boiler shall be limited to 5 very cold start-ups per year, with each start-up not to exceed 270 minutes.

[Rule 1703(a)(2)-PSD-BACT, Rule 2005]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-19 The project owner shall limit the fuel usage to no more than 40 mmcf in any one calendar month. For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler during a non-commissioning year.

The project owner shall limit the fuel usage to no more than 4.28 mmcf in any one calendar month. For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler during the commissioning period.

The project owner shall record and maintain the amount of all fuel combusted during calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to District personnel upon request

[Rule 1303(b)(2) Offset]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-20 **The project owner shall limit the fuel usage to no more than 307 mmcf in any one year. For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler during a non-commissioning year.**

The project owner shall limit the fuel usage to no more than 311 mmcf in any one year. For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler during a commissioning year.

The project owner shall maintain records in a manner approved by the District to demonstrate compliance with this condition. Year is defined as 12-month rolling average. The fuel usage records shall be kept for a period of five years and all records shall be made available to District personnel upon request.

[Rule 1401, Rule 1701 (b), Rule 1303 (b)(2)]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall report the quantity of fuel used during the 12-month rolling average reporting year, assert that they comply with this condition, and report any instances of noncompliance.

AQ-21 **The project owner shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia. The project owner shall also install and maintain a device to continuously record the parameter being measured.**

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. The records shall be kept on site and made available to SCAQMD personnel upon request. The maximum ammonia injection rate shall not exceed 1.9 gal/hr based on 19% aqueous ammonia.

[Rule 1303(a)(1) – BACT, Rule 2005]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly.

AQ-22 **The project owner shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor. The project owner shall also install and maintain a device to continuously record the parameter being measured. The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. The records shall be kept on site and made available to SCAQMD personnel upon request. The catalyst temperature range shall be remain between 550 degree F and 750 degree F. The catalyst inlet temperature shall not exceed 750**

degrees F. The temperature range requirement of this condition does not apply during start-up operations of the boiler listed in condition of certification AQ-9.

[Rule 1303(a)(1) – BACT, Rule 2005]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly.

AQ-23 The project owner shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column. The project owner shall also install and maintain a device to continuously record the parameter being measured. The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. The records shall be kept on site and made available to SCAQMD personnel upon request. The pressure drop across the catalyst and ammonia injection grid shall not exceed 4.5 inches water column.

[Rule 1303(a)(1) – BACT, Rule 2005]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly.

AQ-24 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be Tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	15 minutes	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	15 minutes	Outlet of the SCR serving this equipment
SOx emissions	SCAQMD Laboratory Method 307-91	Not applicable	Fuel Sample
PM emissions	District method 5.1	1 hour minimum	Outlet of the SCR serving this equipment
NH3 emissions	District method 201.7 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted after SCAQMD approval of the source test protocol, but no later than 180 days after initial start-up. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test. The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (mmcf/hour), and the flue gas flow rate.

The test shall be conducted in accordance with SCAQMD approved test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 45 days before the proposed test date and shall be approved by the SCAQMD before the test commences.

The test protocol shall include the proposed operating conditions of the boiler during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted for each load, while firing at maximum, minimum and low firing rates. The test shall be conducted for compliance verification of the 25 ppmv CO limit.

The test shall be conducted for compliance verification of the 5 ppmv NOx limit. The test shall be conducted for compliance verification of the 5 ppmv ammonia slip limit.

Two complete copies of source test reports (include the application number and a copy of the permit in the report) shall be submitted to the District (addressed to south coast air quality management district, attn Roy Olivares (or successor), P.O. Box 4941, Diamond bar, CA 91765). The results in writing shall be submitted within 45 days after the source test is completed. It shall include, but not be limited to emissions rate in pounds per hour and concentration in ppmv at the outlet of the boiler.

A testing laboratory certified by the SCAQMD laboratory approval program (LAP) in the required test methods for criteria pollutant to be measured, and in compliance with district rule 304 (no conflict of interest) shall conduct the test.

Sampling facilities shall comply with the SCAQMD "guidelines for construction of sampling and testing facilities", pursuant to rule 217.

Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 2005, Reg 1703(a-PSD-BACT]

Verification: The project owner shall submit to the CPM for review and the District for approval, the project owner's proposed test protocol. The project owner shall submit evidence of the District's approval of the test protocol within 5 days of receipt. The project owner shall submit a report documenting results of the testing no less than 30 days after producing the report.

AQ-25 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be Tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	60 minutes	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the District within 45 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 7 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 BACT concentration limit.

[Rule 1303(a)(1) – BACT]

Verification: The project owner shall submit a report documenting results of the testing no less than 30 days after producing the report.

AQ-26 The project owner shall install and maintain a CEMS to measure the following parameters: CO concentration in ppmv

Concentrations shall be corrected to 3 percent oxygen on a dry basis The CEMS shall be installed and operated no later than 90 days after initial start-up of the boiler, and in accordance with an approved SCAQMD Rule 218 CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD. Within two weeks of the boiler start-up, the project owner shall provide written notification to the District of the exact date of start-up. The CEMS shall be installed and operated to measure CO concentrations over a 15 minute averaging time period. The CEMS would convert the actual CO concentrations to mass emission rates (lbs/hr) using the equation below and record the hourly emission rates on a continuous basis.

CO Emission Rate, lbs/hr = K Cco Fd[20.9% - %O2 d)][(Qg * HHV)/106], where:

K = 7.267 *10^{-8} (lb/scf)/ppm
Cco = Average of four consecutive 15 min. ave. CO concentration, ppm

Fd = 8710 dscf/MMBTU natural gas
$\%O_2$ d = Hourly ave. % by vol. O_2 dry, corresponding to Cco
Qg = Fuel gas usage during the hour, scf/hr
HHV = Gross high heating value of fuel gas, BTU/scf

[Rule 1703(a)(2)– PSD-BACT, Rule 218]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly.

AQ-27 The project owner shall install and maintain a CEMS to measure the following parameters: NOx concentration in ppmv

Concentrations shall be corrected to 3 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 90 days after initial start-up of the boiler and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the project owner shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the boiler start-up date, the project owner shall provide written notification to the District of the exact date of start-up. The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start up of the boiler. [Rule 2005; Rule 2012, Rule 1703]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly.

AQ-28 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number [AQ-29]
Condition Number [AQ-30]

[Rule 1303(a)(1) – BACT, Rule 2005-BACT]

Verification: None required.

AQ-29 For the purpose of the following condition numbers, continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number: [AQ-31]

[Rule 1303(a)(1) – BACT, Rule 2005-BACT]

Verification: None required.

AQ-30 The project owner shall comply with the following requirements

This boiler shall not be operated unless the flue gas recirculation system is in full operation.

The project owner shall have the burner equipped with a control system to automatically regulate the combustion air, fuel, and recirculation flue gas as the boiler load varies. This control system shall be adjusted and tuned according to the manufacturer's specifications to maintain its ability to repeat the same performance at the same firing rate.

[Rule 1303 (a), Rule 2005]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly. As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-31 The project owner shall comply with the following requirements:

§60.49b Reporting and record keeping requirements and shall include the following:

(a)(1) The design heat input capacity of the boilers and the type of fuels to be used by the equipment.

(a)(2) If applicable, a copy of any federally enforceable requirements that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(ii), 60.44b(c), (d), (e), (i),(j), (k), 60.45b(d), (g), 60.46b(h)(1), or 60.48b(i).

(a)(3) The annual capacity factor at which the project owner anticipated operating the project based on all fuels fired and based on each individual fuel fired.

§60.49b(d)(1) The owner or operator of an affected project shall record and maintain records of the amounts of each fuel combusted each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12 month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

§60.49b(g) The project owner of the boilers subject to the NOx standards under 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NOx emissions rate (expressed as NO2)(ng/J or lb/mmbtu heat input;

(3) The 30 day average NOx emission rate calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emissions rate for the proceeding 30 steam generating unit operating days;

(4) Identification of the steam unit operating days when the calculated 30-day average NOx emissions rates are in excess of the NOx emissions standards under 60.44b, with the reasons for such excess emissions as well as a description of corrective action taken;

(5) Identifications of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective action taken;

(6) Identification of the times when emissions data have been excluded from the calculations of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of CEMs;

(9) Description of any modifications to the CEMs that could affect the ability of the CEMs to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMs drift test and quarterly accuracy assessments as required under Appendix F, Procedure 1 of this part.

§60.49b (h) The owner or operator of any affected project in any category listed in paragraph (h)(1) or (2) of this section is required to submit excess emission reports for any excess emission that occurred during the reporting period.

§60.49b (i) The owner or operator of any affected project subject to the continuous monitoring requirements for NOx under §60.48b shall submit reports containing the information recorded under paragraph (g) of this section.

The project owner shall comply with remaining sections of this subpart, if applicable.

[40 CFR 60 Subpart Db]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly. As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-32 The project owner shall comply with the following requirements:

The ammonia injection system shall be placed in full operation as soon as the minimum temperature is reached. The minimum temperature is listed as 550 degrees F. at the inlet to the SCR reactor.

[Rule 1303(a)(1) – BACT, Rule 2005]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-33 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
PM	40CFR60, SUBPART	Db
SOX	40CFR60, SUBPART	Db
NOx	40CFR60, SUBPART	Db

[40CFR 60 SUBPART Db]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-34 This equipment shall not be operated unless the project holds 5714 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operations. In addition, this equipment shall not be operated unless the project owner demonstrates to the SCAQMD Executive Officer that, at commencement of each compliance year after the start of operation, the facility holds 5645 pounds RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit. [Rule 2005]

Verification: The project owner shall transmit a copy of their procurement document verification annually. As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-35 The project owner shall keep records in a manner approved by the SCAQMD Executive Officer, for the following parameter(s) or item(s):

Retain all records required by permit for a period of five years and make all records available to district personnel upon request.

The project owner shall record and maintain the amount of all fuel combusted during each calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request.

[Rule 1303 (b)(2), 40 CFR 60 Subpart Db]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall report monthly fuel use by each boiler, assert that they comply with this condition, and report any instances of noncompliance.

AQ-36 The project owner shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use after CEMS certification;
Natural gas fuel use during the commissioning period; and

Natural gas fuel use after the commissioning period and prior to CEMS certification [Rule 2012]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall report fuel use by each boiler during each time period identified in this condition, assert that they comply with this condition, and report any instances of noncompliance.

The following conditions apply individually to each 10.5 mmBTU nighttime preservation boiler (facility total = 2):

AQ-37 The project owner shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM_{10}	33 LBS IN ANY ONE MONTH
CO	86 LBS IN ANY ONE MONTH
SOx	9 LBS IN ANY ONE MONTH
VOC	18 LBS IN ANY ONE MONTH

The project owner shall calculate the calendar monthly emissions for VOC, PM10 and SOx using the equation below and the following emission factors: VOC: 4.2 lb/mmcf; PM10: 7.6 lb/mmcf; CO: 19.72 lb/mmcf and SOx: 2.14 lb/mmcf.

Monthly Emissions, lb/month = X (E.F.)

Where X = monthly fuel usage in mmscf/month and E.F. = emission factor indicated above.

For the purpose of this condition the boiler shall not commence with normal operation until the commissioning process has been completed. The District shall be notified in writing once the commissioning process has been completed. Normal operations may proceed in the same commissioning month provide the project owner follows the requirements listed below.

The project owner shall calculate the commissioning emissions for VOC, SOx, PM10 and CO for the commissioning month (beginning of the month to the last day of commissioning) using the equation below and the following emissions factor; VOC: 5.67 lb/mmcf; PM10 13.65 lb/mmcf; SOx: 2.14 lb/mmcf and CO: 18.96 lb/mmcf.

Commissioning Emissions, lb/month = X * EF

Where X = commissioning fuel usage in mmcf/month and E.F = emission factor indicated above.

The commissioning emissions for VOC, SOx, CO and PM10 shall be subtracted the monthly emissions limits (listed in the table a the top of this condition) and the revised monthly emissions limits will be the maximum emissions allowed for the remaining month.

[Rule 1303 – Offsets]

Verification: The project owner shall submit all emission calculations, fuel use, CEM records and a summary demonstrating compliance of all emission limits stated in this Condition for approval to the CPM on a quarterly basis in the quarterly emissions report (AQ-SC9).

AQ-38 The 9 PPMV NOX emission limit(s) is averaged over 15 minutes at 3 percent O2, dry.

[Rule 2005, Rule 1703(a)(2)– PSD-BACT

Verification: None required.

AQ-39 The project owner shall limit the fuel usage to no more than 4.34 mmcf in any one calendar month.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler.

The project owner shall record and maintain the amount of all fuel combusted during each calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request.

[40 CFR 60 Subpart Dc, Rule 1303(b)(2) Offset]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-40 The project owner shall limit the fuel usage to no more than 0.11 mmcf in any one commissioning period.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler.

The project owner shall record and maintain the amount of all fuel combusted during each calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request.

[40 CFR 60 Subpart Dc, Rule 1303(b)(2) Offset]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-41 The project owner shall limit the fuel usage to no more than 48 mmcf in any one calendar year.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single boiler.

The project owner shall record and maintain the amount of all fuel combusted during each year. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request.

[Rule 1401, Rule 1303 (b(2)]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall report the quantity of fuel used during the reporting year, assert that they comply with this condition, and report any instances of noncompliance.

AQ-42 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOx emissions	District Method 100.1	15 minutes	Outlet stack
CO emissions	District Method 100.1	15 minutes	Outlet stack
SOx emissions	AQMD Laboratory Method 307-91	Not Applicable	Fuel sample
PM emissions	District method 5.1	1 hour minimum	Outlet stack

The test shall be conducted after SCAQMD approval of the source test protocol, but no later than 180 days after initial start-up. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test. The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (mmcf/hour), and the flue gas flow rate.

The test shall be conducted in accordance with SCAQMD approved test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 45 days before the proposed test date and shall be approved by the SCAQMD before the test commences.

The test protocol shall include the proposed operating conditions of the boiler during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted for 15 minutes for each load, while firing at maximum, minimum and low firing rates.

The test shall be conducted for compliance verification of the 25 ppmv CO limit.

The test shall be conducted for compliance verification of the 9 ppmv NOx limit.

Two complete copies of source test reports (include the application number and a copy of the permit in the report) shall be submitted to the District (addressed to south coast air quality management district, attn Roy Olivares (or successor), P.O. Box 4941, Diamond bar, CA 91765). The results in writing shall be submitted within 45 days after the source test is completed. It shall include, but not be limited to emissions rate in pounds per hour and concentration in ppmv at the outlet of the boiler.

A testing laboratory certified by the SCAQMD laboratory approval program (LAP) in the required test methods for criteria pollutant to be measured, and in compliance with district rule 304 (no conflict of interest) shall conduct the test.

Sampling facilities shall comply with the SCAQMD "guidelines for construction of sampling and testing facilities", pursuant to rule 217.

Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 2005, Reg 1703(a-PSD-BACT]

Verification: The project owner shall submit to the CPM for review and the District for approval, the project owner's proposed test protocol. The project owner shall submit evidence of the District's approval of the test protocol within 5 days of receipt. The project owner shall submit a report documenting results of the testing no less than 30 days after producing the report.

AQ-43 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	60 minutes	Outlet stack

The test shall be conducted at least once every five years.

The test shall be conducted for compliance verification of the 9 ppmv NOx RECLAIM concentration limit.

[Rule 2012]

Verification: The project owner shall submit a report documenting results of the testing no less than 30 days after producing the report.

AQ-44 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
PM	40CFR60, SUBPART	Dc
SOX	40CFR60, SUBPART	Dc

[40CFR 60 SUBPART Dc]

Verification: None required.

AQ-45 This equipment shall not be operated unless the facility holds 565 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operations. In addition, this equipment shall not be operated unless the project owner demonstrates to the SCAQMD Executive Officer that, at commencement of each compliance year after the start of operation, the facility holds 563 pounds RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit.

[Rule 2005]

Verification: The project owner shall transmit a copy of their procurement document verification annually. As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-46 The project owner shall keep records in a manner approved by the SCAQMD Executive Officer, for the following parameter(s) or item(s):

Retain all records required by permit for a period of five years and make all records available to district personnel upon request.

The project owner shall record and maintain the amount of all fuel combusted during each calendar month. The fuel usage records shall be kept for a period of five years and all records shall be made available to district personnel upon request.

[Rule 1303 (b)(2), 40 CFR 60 Subpart Dc]

Verification: None required.

The following conditions apply individually to each diesel-fueled internal combustion engine used to power an emergency generator or emergency fire pump:

AQ-47 The project owner shall only use diesel fuel containing the following specified compounds:

COMPOUND	Range	PPM BY WEIGHT
Sulfur	Less than or equal to	15

The project owner shall maintain a copy of the MSDS on site.

[Rule 431.2, Rule 1303 (a)-BACT, Rule 1470, 40 CFR 60 Subpart IIII]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-48 The project owner shall limit the operating time to no more than 200 hours in any one year.

[Rule 1110.2, Rule 1304, Rule 1303 (a), Rule 2005, Rule 1470, Rule 1714]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall report operating time for the previous quarter, assert that they comply with this condition, and report any instances of noncompliance.

AQ-49 The project owner shall limit the operating time to no more than 4.2 hours in any one month.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing.

[Rule 1304, Rule 2012]

Verification: See Verification for AQ-48.

AQ-50 The project owner shall install and maintain a(n) non-resettable elapsed meter to accurately indicate the elapsed operating time of the engine.

[Rule 1110.2, Rule 1304, Rule 1470, Rule 2012, 40 CFR 60 Subpart IIII]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly. The project owner shall submit all dates of operation, elapsed time in hours, and the reason for each operation in the Quarterly Operations Report (AQ-SC9).

AQ-51 The project owner shall comply with the following requirements:
The project owner shall comply with the emission standards specified in 40 CFR 60.4205(B) by purchasing an engine certified to the emission standards in 40 CFR 60.4205(B), as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission related specifications.

[40 CFR 60.4211(c)]

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered professional engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly.

AQ-52 The project owner shall comply with the following requirements.

The project owner shall operate and maintain the stationary engine and control device according to the manufacturer's written emission-related instructions (or procedures developed by the operator that are approved by the engine manufacturer), change only those emission-related settings that are permitted by the manufacturer, and meet the requirements of 40 CFR 89, 94 and/or 1068, as they apply.

[40 CFR 60.4211(a)]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-53 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
PM	District Rule	1470
Sulfur	District Rule	431.2

[Rule 431.2, Rule 1470]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

AQ-54 The project owner shall keep records in a manner approved by the SCAQMD Executive Officer, for the following parameter(s) or item(s):

Manual and automatic operation and shall list all engine operations in each of the following areas:

- **A. Emergency use**
- **B. Maintenance and testing**
- **C. Other (be specific)**

In addition, for each time the engine is manually started, the log shall include the date of engine operation, the specific reason for operation, and the totalizing hour meter reading (in hours and tenths of hours) at the beginning and the end of the operation.

[Rule 1110.2, Rule 1470, 40 CFR 60.4214 (b)]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall report operating time for the previous quarter, assert that they comply with this condition, and report any instances of noncompliance.

AQ-55 The project owner shall keep records in a manner approved by the SCAQMD Executive Officer, for the following parameter(s) or item(s):

On or before January 15th of each year, the project owner shall record in the engine operating log:

A. the total hours of engine operation for the previous calendar year, and
B. The total hours of engine operation for maintenance and testing for the previous calendar year.

Engine operation log(s) shall be retained on site for a minimum of three calendar years and shall be made available to the SCAQMD Executive Officer or representative upon request.

[Rule 1304]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall report operating time for the previous quarter, assert that they comply with this condition, and report any instances of noncompliance.

The following conditions apply individually to each diesel-fueled internal combustion engine used to power an emergency generator:

AQ-56 The project owner shall limit the operating time to no more than 30 minutes in any one day. For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing.

[CEQA]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall report operating time for the previous quarter, assert that they comply with this condition, and report any instances of noncompliance.

The following conditions apply individually to each 3633 BHP diesel-fueled internal combustion engine used to power an emergency generator (facility total = 2):

AQ-57 This equipment shall not be operated unless the facility holds 5922 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operations. In addition, this equipment shall not be operated unless the project owner demonstrates to the SCAQMD Executive Officer that, at commencement of each compliance year after the start of operation, the facility holds 5922 pounds RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit.

[Rule 2005]

Verification: The project owner shall transmit a copy of their procurement document verification annually. As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

The following condition applies to the 398 BHP diesel-fueled internal combustion engine powering an emergency generator (facility total = 1):

AQ-58 This equipment shall not be operated unless the facility holds 434 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operations. In addition, this equipment shall not be operated unless the project owner demonstrates to the SCAQMD Executive Officer, at commencement of each compliance year after the start of operation, the facility holds 434 pounds RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit.

[Rule 2005]

Verification: The project owner shall transmit a copy of their procurement document verification annually. As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

The following conditions apply individually to each 617 BHP diesel-fueled internal combustion engine powering an emergency fire pump (facility total = 3):

AQ-59 The project owner shall limit the operating time to no more than 50 hours in any one year. For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing.

[Rule 1110.2, Rule 1304, Rule 2012, Rule 1470]

Verification: As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall report operating time for the previous quarter, assert that they comply with this condition, and report any instances of noncompliance.

AQ-60 This equipment shall not be operated unless the facility holds 707 pounds of NOx RTCs in its allocation account to offset the annual

emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operations. In addition, this equipment shall not be operated unless the project owner demonstrates to the SCAQMD Executive Officer that, at commencement of each compliance year after the start of operation, the facility holds 707 pounds RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by hold RTCs may be transferred upon their respective expiration dates. His hold amount is addition to any other amount of RTCs required to be held under condition(s)stated in this permit.

[Rule 2005]

Verification: The project owner shall transmit a copy of their procurement document verification annually. As part of the quarterly emissions report required by Condition of Certification AQ-SC9, the project owner shall assert that they comply with this condition and report any instances of noncompliance.

REFERENCES

ARB 2009a (California Air Resources Board) – California Ambient Air Quality Standards available on ARB Website. http://www.arb.ca.gov/aqs/aqs.htm. Accessed 2009.

ARB 2009b (California Air Resources Board) – Air Designation Maps available on ARB website. http://www.arb.ca.gov/desig/adm/adm.htm. Accessed 2009 and 2010.

ARB 2009c (California Air Resources Board) – California Ambient Air Quality Data Statistics available on ARB website. http://www.arb.ca.gov/adam/welcome.html. Accessed 2009 and May 2010.

BRW 2013a – Basin and Range Watch/Laura Cunningham (TN 70697). Status Report No. 2, dated May 8, 2013. Submitted to CEC/Docket Unit on May 8, 2013

CCR 2006 – California Code of Regulations, Chapter 3 (CEQA Guidelines), Article 17, §§15250—15253 as amended on July 11, 2006.

DOT 2013A **–** State Of California, Department Of Transportation, Daniel Kopulsky (Tn 200198). Comments Re: Preliminary Staff Assessment, Dated August 12, 2013. Submitted To Cec/Christine Stora On August 14, 2013

Palen 2012a – Palen Solar Holdings, LLC/Galati Blek, Scott Galati (TN 68910). Palen Solar Holdings LLC's Petition for Amendment, dated December 17, 2012. Submitted to CEC/C. Stora on December 18, 2012

Palen 2013a – Palen Solar Holdings, LLC/Galati Blek, Scott Galati (TN 69471). Palen Solar Holding's Supplement Number One to Support Petition to Amendment, dated February 8, 2013. Submitted to CEC/C. Stora on February 14, 2013

Palen 2013b – Galati Blek/Marie Fleming (TN 69601). Palen Solar Holdings, LLC's Response to Staff's Issue Identification Report, dated February 19, 2013. Submitted to CEC/Dockets Unit on February 19, 2013

Palen 2013c – Palen Solar Holdings, LLC/Galati Blek LLP, Scott Galati (TN 69909). Palen Solar Holdings, LLC's Supplement Number Two – Complete Air Quality and Public Health Sections. Submitted to CEC/C. Stora on March 13, 2013

Palen 2013l – Galati Blek/Scott A. Galati (TN 70785). Palen Solar Holdings, LLC's Response to Workshop Queries, dated May 13, 2013. Submitted to CEC/C. Stora on May 13, 2013

Palen 2013n – Galati Blek/J. Leyva Record (TN 70786). Palen Solar Electric Air Quality Modeling Files, dated May 7, 2013. Submitted to CEC/Docket Unit on May 7, 2013

Palen 2013ff – Galati Blek/Marie Fleming (Tn 71690). Revised Supplement No. 2, Complete Air Quality & Public Health Sections, Dated July 19, 2013. Submitted To Cec/Docket Unit On July 19, 2013

Palen 2013pp – Galati Blek/Marie Fleming (Tn 200077). Palen Solar Holdings, Llc's Final Comments On The Preliminary Staff Assessment, Dated July 29, 2013. Submitted To Cec/Docket Unit On July 29, 2013

SCAQMD 2013a – South Coast Air Quality Management District/Mohsen Nazemi (TN 70277). Letter to Roger Johnson, dated April 5, 2013. Submitted to CEC/Dockets Unit on April 11, 2013

SCAQMD 2013b – South Coast Air Quality Management District/Mohsen Nazemi (TN 70536). Completeness Letter for the Palen Solar Electric Generation Project to Charles Turlinski, dated April 26, 2013. Submitted to CEC/Docket Unit April 30, 2013

SCAQMD 2013c – South Coast Air Quality Management District/Mohsen Nazemi (TN 200951). Preliminary Determination of Compliance (PDOC) for Palen Solar Electric Generation Station, (Facility ID# 174021), to be located at Corn Spring Road, Desert Center, CA 92239, dated October 18, 2013. Submitted to CEC/Docket Unit on October 18, 2013

SEC 2013a – Southern California Edison. Red Bluff Substation. Retrieved June 12, 2013, from https://www.sce.com/wps/portal/home/about-us/reliability/upgrading-transmission/red-bluff

U.S.EPA 2013a – United States Environmental Protection Agency. The Green Book Nonattainment Areas for Criteria Pollutants. http://www.epa.gov/oar/oaqps/greenbk/index.html. Accessed October 2009 and 2010.

U.S.EPA 2013b – United States Environmental Protection Agency. Air Data database ambient air quality data for Blythe, Palm Springs and Victorville California.

http://www.epa.gov/aqspubl1/annual_summary.html. Accessed October 2009 and May 2010.

WC (Weather Channel) 2013. Averages and records for Desert Center, California. Website: http://www.weather.com. Accessed October 2013.

ACRONYMS

AAQS	Ambient Air Quality Standard
ACC	Air Cooled Condenser
AERMOD	ARMS/EPA Regulatory Model
AFC	Application for Certification
APCO	Air Pollution Control Officer
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMD	Air Quality Management District
AQMP	Air Quality Management Plan
ARB	California Air Resources Board
ASOS	Automated Surface Observing Systems
ATC	Authority to Construct
ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
bhp	brake horsepower
BLM	Bureau of Land Management
Btu	British Thermal Unit
CCR	California Code of Regulations
CEC	California Energy Commission (or Energy Commission)
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPM	(CEC) Compliance Project Manager
DPM	Diesel Particulate Matter
Degrees F	Degrees Fahrenheit
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
FDOC	Final Determination Of Compliance
FSA	Final Staff Assessment
GHG	Greenhouse Gas
H_2S	Hydrogen Sulfide
HTF	Heat Transfer Fluid
hp	horsepower
HSC	Health and Safety Code

kV	Kilovolt
lbs	Pounds
LORS	Laws, Ordinances, Regulations and Standards
LLC	Limited Liability Company
LPG	Liquefied Petroleum Gas
MCR	Monthly Compliance Report
MDAB	Mojave Desert Air Basin
MDAQMD	Mojave Desert Air Quality Management District
μg/m3	microgram per cubic meter
mg/m3	milligrams per cubic meter
MMBtu/hr	Million British Thermal Units per Hour
MW	Megawatts (1,000,000 Watts)
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standard
~~NEPA~~	~~National Environmental Protection Act~~
NMHC	Non-Methane Hydrocarbon
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen or Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
O_3	Ozone
OLM	Ozone Limiting Method
PDOC	Preliminary Determination Of Compliance
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PSA	Preliminary Staff Assessment (this document)
PSEGS	Palen Solar Electric Generating System
PSD	Prevention of Significant Deterioration
PSH	Palen Solar Holding (project owner)
PTC	Permit to Construct
PTO	Permit to Operate

RO	Reverse Osmosis
ROW	Right of Way
SA/DEIS	Staff Assessment/Draft Environmental Impact Statement
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
scf	standard cubic feet
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_4	Sulfate
SOx	Oxides of Sulfur
SoCAB	South Coast Air Basin
SSAB	Salton Sea Air Basin
SWPPP	Storm Water Pollution Prevention Plan
TDS	Total Dissolved Solids
tpy	tons per year
U.S.EPA	United States Environmental Protection Agency
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compounds
WC	Weather Channel

APPENDIX AIR-1 – GREENHOUSE GAS EMISSIONS

Jacquelyn Leyva Record and David Vidaver

SUMMARY OF CONCLUSIONS

The Palen Solar Electric Generating System (PSEGS) project owner is proposing to replace the parabolic trough solar collection system and associated heat transfer fluid (HTF) system previously approved by the California Energy Commission (Energy Commission) for the Palen Solar Power Plant (PSPP) with solar tower technology. Text using the term PSEGS refers to the currently proposed modified project design while the term PSPP refers to the previously approved design.

The PSEGS solar tower technology would make steam to run a steam turbine generator by using a field of heliostats—elevated mirrors, each approximately 12 feet tall, mounted on pylons and guided by a sun-tracking system—to focus the sun's rays on a solar receiver steam generator on top of a 750-foot solar tower located near the center of each solar field. The proposed modified PSEGS project is comprised of two solar plants, each of which would have 250-MW of capacity, totaling 500 MW for the facility. As a solar project, its greenhouse gas (GHG) emissions would be considerably less than the existing statewide average GHG emissions per unit of generation and considerably less than the GHG emissions from existing fossil fuel–fired power plants providing generation to California, and thus would contribute to continued reduction of GHG emissions in the interconnected California and the western United States electricity systems.

The operating emissions of the modified PSEGS were provided by the project owner in the amendment application. The values used in this section are from the amendment application, updated as needed with additional information obtained from supplemental data from the applicant and from the PDOC ~~but may change as a result of the air district's evaluation of the project and GHG emissions will be updated as needed in the Final Staff Assessment (FSA).~~ Operating emissions for the previously approved PSPP were estimated at 14,818 metric tons of carbon dioxide equivalent per year. The applicant's estimated emissions for PSEGS are ~~82,325~~ 44,720 metric tons of carbon dioxide equivalent emissions per year (without support on-site vehicles) and 77,720 with on-site vehicles as shown in **Greenhouse Gas Table 3**. This is due to increased fuel use in the PSEGS auxiliary and nighttime preservation boilers compared to the approved PSPP which did not have these additional boilers.

While PSEGS would emit some GHG emissions, the contribution of PSEGS to the system build-out of renewable resources to meet the goals of the Renewable Portfolio Standard (RPS) in California would result in a net cumulative reduction of fossil-fueled energy generation and GHG emissions from new and existing fossil fueled electricity resources. Electricity is produced by operation of inter-connected generation resources. Operation of one power plant, like PSEGS, affects all other power plants in the interconnected system. PSEGS would be a "must-take" facility and its operation would affect the overall electricity system operation and GHG emissions in several ways:

- PSEGS would displace higher GHG-emitting electricity generation. Because the project's GHG emissions per megawatt-hour (MWh) would be largely based upon renewable solar generation, GHG emissions would be much lower than power plants that the project would displace even with use of natural gas in the ~~auxiliary~~ boilers. Therefore, the addition of the PSEGS would contribute to a reduction of California and overall Western Electricity Coordinating Council system GHG[14] emissions and GHG emission rate average and would be part of California's programmatic approach to meeting GHG emissions reduction goals.

- PSEGS would facilitate to some degree the replacement of out-of-state high-GHG-emitting (e.g., coal) electricity generation that must be phased out in conformance with the State's Emissions Performance Standard.
- PSEGS could facilitate to some extent the replacement of generation provided by aging power plants and those that use once-through cooling (OTC).

These system interactions would result in a net reduction in GHG emissions across the electricity system, while providing energy and capacity to California. Thus, staff concludes that the proposed modified project would result in a cumulative overall reduction in GHG emissions from power plants, does not worsen current conditions, and would not result in impacts that are cumulatively California Environmental Quality Act (CEQA) significant.

Staff concludes that the short-term minor emission of GHGs during construction that are necessary to create this new, low-GHG-emitting power generating facility would be sufficiently reduced by "best practices" and would be more than offset by GHG emission reductions during operation. Thus, construction GHG emissions would not be CEQA significant.

The PSEGS project, as a solar project with a nightly shutdown, would operate significantly less than a 60 percent capacity factor and therefore would not be subject to the requirements of Senate Bill (SB) 1368 (Greenhouse Gases Emission Performance Standard; Title 20, California Code of Regulations, section 2900 et. seq.). However, PSEGS would easily comply with the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard.

INTRODUCTION

The generation of electricity using fossil fuels, even in an auxiliary boiler or back-up generator at a thermal solar plant, produces GHG emissions in addition to the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts (CAA). The **AIR QUALITY** section evaluates PSEGS for these criteria pollutants and this appendix evaluates PSEGS for GHG emissions.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The following federal, state, and local laws and policies in **Greenhouse Gas Table 1** pertain to the control and mitigation of GHG emissions. Staff's analysis examines the proposed modified project's compliance with these requirements.

[14] Fuel-use closely correlates to the efficiency of and carbon dioxide (CO_2) emissions even from renewable power plants.

AIR QUALITY GHG ANALYSIS

California is actively pursuing policies to reduce GHG emissions that include adding low-GHG emitting renewable electricity generation resources to the system. The GHGs evaluated in this analysis include carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFC), and perflurocarbons (PFC). CO_2 emissions are far and away the most common of these emissions; as a result, even though the other GHGs may have a greater impact on climate change on a per-unit basis due to their greater global warming potential as described more fully below, GHG emissions are often "normalized" in terms of metric tons of CO_2-equivalent (MTCO2E) for simplicity. Global warming potential (GWP) is a relative measure, compared to carbon dioxide, of a compound's ability to warm the planet, taking into account each compound's expected residence time in the atmosphere. By convention, carbon dioxide is assigned a global warming potential of one. In comparison, for example methane has a GWP of 21, which means that it has a global warming effect 21 times greater than carbon dioxide on an equal-mass basis. The carbon dioxide equivalent (CO2E) for a source is obtained by multiplying each GHG by its GWP and then adding the results together to obtain a single, combined emission rate representing all GHGs in terms of CO2E.

GHG emissions are not included in the class of pollutants traditionally called "criteria pollutants." Since the impact of the GHG emissions from a power plant's operation has global rather than local effects, those impacts should be assessed not only by analysis of the plant's emissions, but also in the context of the operation of the entire electricity system of which the plant is an integrated part. Furthermore, the impact of the GHG emissions from a power plant's operation should be analyzed in the context of applicable GHG laws and policies, especially Assembly Bill (AB) 32, California's Global Warming Solutions Act of 2006.

GLOBAL CLIMATE CHANGE AND CALIFORNIA

Worldwide, with the exception of 1998, over the past 132-year record the nine warmest years all have occurred since 2000, with the two hottest years on record being 2010 and 2005 (NASA 2013). According to "The Future Is Now: An Update on Climate Change Science Impacts and Response Options for California," an Energy Commission document, the American West is heating up faster than other regions of the United States (CEC 2009e). The California Climate Change Center (CCCC) reports that, by the end of this century, average global surface temperatures could rise by 4.7°F to 10.5°F due to increased GHG emissions.

The accumulation of GHGs in the atmosphere regulates the earth's temperature. Without these natural GHGs, the earth's surface would be approximately 61°F (34°C) cooler (CalEPA 2006); however, emissions from fossil fuel combustion for activities such as electricity production and vehicular transportation have elevated the concentration of GHGs in the atmosphere above natural levels. California Air Resources Board (ARB) estimated that the mobile source sector accounted for approximately 38 percent of the GHG emissions generated in California in 2009, while the electricity generating sector accounted for approximately 23 percent of the 2009 California GHG emissions inventory with just more than half of that from in-state generation sources (ARB 2011).

The Fourth U.S. Climate Action Report concluded, in assessing current trends, that CO_2 emissions increased by 20 percent from 1990 to 2004, while methane and nitrous oxide emissions decreased by 10 percent and 2 percent, respectively. The Intergovernmental Panel on Climate Change (IPCC) constructed several emission trajectories of GHGs needed to stabilize global temperatures and climate change impacts. It concluded that stabilization of GHGs at 450 ppm carbon dioxide equivalent concentration is required to keep the global mean warming increase below 3.8°F (2.1°C) from year 2000 base line levels (IPCC 2007a).

GHGs differ from criteria pollutants in that GHG emissions from a specific project do not cause direct adverse localized human health effects. Rather, the direct environmental effect of GHG emissions is the cumulative effect of an overall increase in global temperatures, which in turn has numerous indirect effects on the environment and humans. The impacts of climate change include potential physical, economic and social effects. These effects could include inundation of settled areas near the coast from rises in sea level associated with melting of land-based glacial ice sheets, exposure to more frequent and powerful climate events, and changes in suitability of certain areas for agriculture, reduction in Arctic sea ice, thawing permafrost, later freezing and earlier break-up of ice on rivers and lakes, a lengthened growing season, shifts in plant and animal ranges, earlier flowering of trees, and a substantial reduction in winter snowpack (IPCC 2007b). For example, current estimates include a 70 to 90 percent reduction in snow pack in the Sierra Nevada mountain range. Current data suggest that in the next 25 years, in every season of the year, California could experience unprecedented heat, longer and more extreme heat waves, greater intensity and frequency of heat waves, and longer dry periods. More specifically, the CCCC predicted that California could witness the following events (CCCC 2006):

- Temperature rises between 3 and 10.5 ºF
- 6 to 20 inches or greater rise in sea level
- 2 to 4 times as many heat-wave days in major urban centers
- 2 to 6 times as many heat-related deaths in major urban centers
- 1 to 1.5 times more critically dry years
- Losses to mountaintop snowpack and water supply (e.g., according to the CCCC, Sierra Nevada snowpack could be reduced by as much as 70 to 90 percent by 2100 [CEC 2009e])
- 25 to 85 percent increase in days conducive to ozone formation
- 3 to 20 percent increase in electricity demand
- 10 to 55 percent increase in the risk of wildfires

There is general scientific consensus that climate change is occurring and that human activity contributes in some measure (perhaps substantially) to that change. Man-made emissions of GHGs, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. Indeed, the California Legislature finds that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California" (Cal. Health & Safety Code, sec. 38500, division 25.5, part 1).

The state has demonstrated a clear willingness to address global climate change (GCC) through research, adaptation[15], and GHG emission reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation (see **Electricity System GHG Impacts** below), and describes the applicable GHG policies and programs.

In April 2007, the U.S. Supreme Court held that GHG emissions are pollutants within the meaning of the CAA. In reaching its decision, the Court also acknowledged that climate change results, in part, from anthropogenic causes (Massachusetts et al. v. Environmental Protection Agency 549 U.S. 497, 2007). The Supreme Court's ruling paved the way for the regulation of GHG emissions by U.S. Environmental Protection Agency (U.S. EPA) under the CAA.

In response to this Supreme Court decision, on December 7, 2009 the U.S. EPA Administrator signed two distinct findings regarding GHGs under Section 202(a) of the CAA:

- Endangerment Finding:[16] That the current and projected concentrations of the GHGs in the atmosphere threaten the public health and welfare of current and future generations; and
- Cause or Contribute Finding: That the combined emissions of GHGs from new motor vehicles and new motor vehicle engines contribute to the GHG pollution which threatens public health and welfare.

As a result, regulating GHGs at the federal level is now required by U.S. EPA's Prevention of Significant Deterioration Program (PSD) for sources that exceed 100,000 tons per year of carbon dioxide-equivalent emissions and federal rules require federal reporting of GHGs. As federal rulemaking evolves, staff at this time focuses on analyzing the ability of the project to comply with existing federal- and state-level policies and programs for GHGs.

In 1998, the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p. 5). In 2003, the Energy Commission recommended that the state require reporting of GHGs or global climate change[17] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the ARB to adopt standards to reduce statewide GHG emissions to GHG emissions levels that existed in 1990, with such reductions to be achieved by 2020. To achieve this, ARB has a mandate to define the 1990 emissions level and achieve the maximum technologically feasible and cost-

---

[15] While working to understand and reverse global climate change, it is prudent to also adapt to potential changes in the state's climate (for example, changing rainfall patterns).

[16] The Supreme Court is expected to once again review the endangerment finding in early 2014, according to an article published online October 15, 2013 by E & E Publishing.

[17] Global climate change is the result of greenhouse gases, or air emissions with global warming potentials, affecting the global energy balance and thereby the global climate of the planet. The terms greenhouse gases (GHGs) and global climate change (GCC) gases are used interchangeably.

effective GHG emission reductions to meet this requirement. Executive Order S-3-05 signed by then-Governor Arnold Schwarzenegger in June 2005, also requires ARB to plan for further GHG emissions reductions to achieve an 80 percent reduction from 1990 GHG emissions by the year 2050.

The ARB adopted early action GHG reduction measures in October 2007, adopted mandatory reporting requirements and the 2020 statewide target in December 2007, and adopted a statewide scoping plan in December 2008, to identify how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. ARB adopted regulations implementing cap-and-trade regulations on December 22, 2011, and ARB staff continues to develop and implement regulations to refine key elements of the GHG reduction measures to improve their linkage with other GHG reduction programs. Federal and state mandatory reporting and state cap-and-trade requirements all apply to this project.

Greenhouse Gas Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Federal	
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule “tailors” GHG emissions to PSD and Title V permitting applicability criteria.
40 Code of Federal Regulations (CFR) Parts 51 and 52	A new stationary source that emits more than 100,000 TPY of GHGs is considered to be a major stationary source subject to Prevention of Significant Determination (PSD) requirements. This project would not trigger this 100,000 TPY PSD threshold.
40 Code of Federal Regulations (CFR) Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year. This requirement is triggered by this project.
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the California Air Resource Board (ARB) to enact standards to reduce GHG emission to 1990 levels by 2020. Electricity production facilities will be regulated by the ARB. A cap-and-trade program became active in January 2012, with enforcement beginning in January 2013. Cap-and-trade is expected to achieve approximately 20 percent of the GHG reductions expected under AB 32 by 2020.
California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
Title 20, California Code of Regulations, section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009 (also known as SB 1368)	The regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 $MTCO_2$/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO_2/MWh).

The California Climate Action Team produced a report to the Governor (CalEPA 2006) which included many examples of strategies that the state could pursue to reduce GHG emissions in California, in addition to several strategies that had been recommended by the Energy Commission and the California Public Utilities Commission (CPUC). Their third biennial report published in December 2010 and required by Executive Order S-3-05, is the most recent report addressing actions that California could take to reduce GHG emissions (CalEPA 2010). The scoping plan approved by ARB in December 2008 builds upon the overall climate change policies of the Climate Action Team reports and includes recommended strategies to achieve the goals for 2020 and beyond. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). The scoping plan includes a 33 percent RPS, aggressive energy efficiency targets, and a cap-and-trade program that includes the electricity sector (ARB 2008). Mandatory compliance period[18] with cap-and-trade requirements commenced on January 1, 2012, although enforcement was delayed until January 2013. SB 2 (Simitian, Chapter 1, Statutes of 2011-12) expresses the intent of the California Legislature to have 33 percent of California's electricity supplied by renewable sources by 2020 and the PSEGS Project would contribute to this goal.

It is likely that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will be based on cost-effectiveness (i.e., the greatest GHG reduction for the least cost). For example, ARB proposes a 40 percent reduction in statewide GHG emissions from the electricity sector even though that sector currently only produces about 25 percent of the state's GHG emissions.

SB 1368,[19] enacted in 2006, and regulations adopted by the Energy Commission and the CPUC, pursuant to that bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Emission Performance Standard (EPS) of 0.5 metric tonnes CO_2 per megawatt-hour[20] (1,100 pounds CO_2/MWh). Specifically, the SB 1368 EPS applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California.[21] If a project, instate or out of state, plans to sell base load electricity to California utilities, those utilities will have to demonstrate that the project meets the EPS. *Base load* units are defined as units that are expected to operate at a capacity factor higher than 60 percent. Compliance with the EPS is determined by dividing the annual average carbon dioxide emissions by the annual average net electricity production in MWh. This determination is based on capacity factors, heat rates, and corresponding emissions rates that reflect the *expected* operations of the power plant

[18] A compliance period is the time frame during which the compliance obligation is calculated. The years 2013 and 2014 are known as the first compliance period and the years 2015 2017 are known as the second compliance period. The third compliance period is from 2018 2020. At the end of each compliance period each facility will be required to turn in compliance instruments, including allowances and a limited number of ARB offset credits equivalent to their total GHG emissions throughout the compliance period. (http://www.arb.ca.gov/cc/capandtrade/guidance/chapter1.pdf)

[19] Public Utilities Code § 8340 et seq.

[20] The Emission Performance Standard only applies to carbon dioxide and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

[21] See Rule at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm

and not on full load heat rates [Chapter 11, Article 1 §2903(a)]. At the January 12, 2012, Business Meeting, the Energy Commission opened an Order Instituting Rulemaking (12-OIR-1) to consider revisions to the EPS.

In addition to these programs, California is involved in the Western Climate Initiative (WCI), a multi-state and international effort to establish a cap-and-trade market to reduce GHG emissions in the Western United States and the Western Electricity Coordinating Council (WECC). WCI created a special entity, WCI, Inc. to assist jurisdictions that are moving ahead with cap-and-trade programs. The initial participants are California and the Canadian province of Quebec. Two other Canadian provinces may join in the near future.

Each participating entity is developing their own cap-and-trade program to reduce GHG pollution, using their own authorities, laws and regulations. These programs will be linked in a larger market if each participating organization finds that such joining of programs creates synergy and can be done without adversely impacting their own system.

WCI timelines are similar to those of AB 32, with full roll-out beginning in 2012. And, as with AB 32, the electricity sector has been a major focus of attention of this group. ARB continues to refine AB 32 regulations to mesh California requirements with those of the WCI to minimize leakage of GHG emissions from one geographic area to another. For example, they held a staff workshop on April 9, 2012, to discuss draft amendments to California's cap-and-trade program to better link these two efforts. None of the proposed amendments would change GHG requirements for PSEGS.

SB 1018 (Unfinished Business, Senate Budget and Fiscal Review Committee, for purposes of implementing the Budget Act of 2012) establishes new legislative oversight and controls over the ARB including: the creation of a separate expenditure fund for proceeds from the auction or sale of allowances pursuant to the market-based compliance mechanism (their cap-and-trade program); the establishment of a separate Cost of Implementation Fee account for oversight and tracking of funds; oversight of actions taken on behalf of the State of California related to market-based compliance and auctions, specific to the Western Climate Initiative and Western Climate Initiative, Incorporated; and provides for return of certain funds to ratepayers of Investor Owned Utilities from funds related to the auction or sale of allowances.

If built, PSEGS would be required to participate in California's GHG cap-and-trade program. This cap-and-trade program is part of a broad effort by the State of California to reduce GHG emissions as required by AB 32, which is being implemented by ARB. As currently proposed, market participants such as PSEGS would be required to report their GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions by purchasing allowances from the capped market and offsets from outside the AB 32 program. As new participants enter the market and as the market cap is ratcheted down over time, GHG emission allowance and offset prices will increase encouraging innovation by market participants to reduce their GHG emissions. Thus, PSEGS, as a GHG cap-and-trade participant, would be consistent with California's landmark AB 32 Program, which is a statewide program coordinated with a region wide WCI program to reduce California's GHG emissions to 1990 levels by 2020.

ELECTRICITY PROJECT GREENHOUSE GAS EMISSIONS

Electricity use can be as simple as turning on a switch to operate a light or fan. The system to deliver the adequate and reliable electricity supply is complex and variable. But it operates as an integrated whole to reliably and effectively, meet demand, such that the dispatch of a new source of generation unavoidably curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). Ancillary services[22] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

PSEGS GHG EMISSIONS

Project Construction

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in short-term, unavoidable increases in vehicle and equipment emissions that include GHGs. The construction would last approximately 33 months. The GHG emissions estimate, for the entire construction period, provided by the project owner is below in **Greenhouse Gas Table 2**. Construction period GHG emissions average 16,485 MTCO2E per year (45,335 MTCO2E/33 months) X (12 months in a year).

Greenhouse Gas Table 2
Estimated PSEGS Potential Construction Greenhouse Gas Emissions

Construction Element	CO_2 Equivalent (MTCO2E)[1,2,3]
On-Site Construction Equipment (includes delivery and hauling vehicles)	31,560
On-Site Motor Vehicles (LTDs)	83
Off-Site Motor Vehicles	13,692
Construction Total (33 months)	45,335

Notes:
1 - One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms
2 - The vast majority of the CO2E emissions, over 99%, is CO_2 from these combustion sources.
3 – Values shown per period for construction. Days per period: 21 days per month at 33 months = 693 days total
Source: Palen 2013c, Appendix 4.1E

Project Operations

~~The final operational PSEGS impacts will be evaluated in the FSA.~~ Shown below in **Greenhouse Gas Table 3** is the ~~evaluation performed by the applicant for~~ operating PSEGS emissions data for GHGs including carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFC), and

[22] See CEC 2009b, page 95.

perflurocarbons (PFC). The primary sources that would cause GHG emissions would be from power block auxiliary boilers and nighttime preservation boilers, and maintenance activities, including mirror cleaning and minimal undesired vegetation removal, weekly testing of the emergency generator and firewater pump, daily operation of each boiler (five hours per day of operation plus additional hours for startup of each auxiliary boiler and twelve to sixteen hours per day of operation plus an hour for startup of each nighttime boiler) and employee commute trips. ~~These values are preliminary at this time and may need to be updated in the FSA, depending on the outcome of the Determination of Compliance after it has been issued.~~

Greenhouse Gas Table 3
PSEGS, Estimated Potential Greenhouse Gas (GHG) Emissions

	Maximum Emissions, metric tonnes/yr				
Emitting Source	**CO_2**	**CH_4**	**N_2O**	**SF_6**	**CO_2-equivalent (MTCO2E[a] per year)**
Auxiliary Boilers[c]	37,658	0.72	0.04	--	~~35,100~~ 37,659
Nighttime Preservation Boilers	5,922	0.1	0.02	--	~~5,710~~ 5,922
Power Block Emergency Generator	778	0.024	7.6E-3	--	~~827~~ 778
Common Area Emergency Generator	45	1.7E-03	3.8E-3	--	45
Power Block Fire Pump Engine	152	4.0E-03	1.4E-03	--	152
Common Area Fire Pump Engine	76	2.0E-03	7.0E-04	--	76
WSACs	0	0.00	0.00	--	0
Equipment Leakage (SF_6)	--	--	--	2.0E-03	2.0E-03
Total	44,631	0.8517	0.0735	2.0E-03	44,631
Global warming potential multiplier	1x	21x	310x	23,900x	
Total Project GHG Emissions – MTCO2E [b]	**44,631**	**17.89**	**22.79**	**47.8**	**44,720**
On-Site Maintenance Vehicles [d]	--	--	--	--	~~36,151 + 1,554~~ 33,000
MTCO2	**44,631**	**MTCO2E [b]**			**~~79,750~~[h] 77,720**
Facility MWh per year [e]	1,412,300				1,412,300
Facility CO_2 EPS (MTCO2/MWh)	0.032[g]	Facility GHG Performance (MTCO2E/MWh)			~~0.06~~ 0.055[f]

Source: Palen 20113ff, Table4.1A-13 Palen Source Emissions, SCAQMD 2013c, and staff estimate for employee vehicles.
a. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
b. Annualized basis uses the project assumed maximum permitted operating basis.
c includes worse case of high boost mode, low mode, and a startup/shutdown per day.
d includes the mirror washing machines (MWMs), (light duty trucks) LDTs, and Water Trucks.
e estimated gross MWh
f value includes on-site maintenance vehicles
g value does not include on-site maintenance vehicles
h reported in previous document incorrectly at 82,325

Solar Project Energy Payback Time

The beneficial energy and GHG impacts of renewable energy projects can also be measured by the *energy payback time.*[23] **Greenhouse Gas Tables 2** and **3** (to be provided in the FSA) provide an estimate of the onsite construction and operation emissions, employee transportation emissions, and the final segment of offsite materials and consumables transportation. However, there are additional direct transportation and indirect manufacturing GHG emissions associated with the construction and operation of the proposed modified project, which are all considered in the determination of the energy payback time. A document sponsored by Greenpeace estimates that the energy payback time for concentrating solar power plants, such as PSEGS, to be on the order of 5 months (Greenpeace 2005, Page 9); and the project life for PSEGS is on the order of 30 years. Therefore, the proposed modified project's GHG emissions reduction potential from energy displacement would be substantial.[24]

Closure and Decommissioning

Closure and decommissioning, as a one-time limited duration event, would have emissions that are similar in type and magnitude, but likely lower than, the construction emissions discussed above.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses four kinds of impacts: construction, operation, closure and decommissioning, and cumulative effects. As the name implies, construction impacts result from the emissions occurring during the construction of the proposed modified project. The operation impacts result from the emissions of the proposed modified project during operation. Cumulative impacts analysis assesses the impacts that result from the proposed modified project's incremental effect viewed over time. The impact of GHG emissions caused by this solar facility is characterized by considering how the power plant would affect the overall electricity system. The integrated electricity system depends on non-fossil and fossil-fueled generation resources to provide energy and satisfy local capacity needs. As directed by the Energy Commission's adopted order initiating an informational (OII) proceeding (08-GHG OII-1) (CEC 2009a), staff is refining and implementing the concept of a "blueprint" that describes the long-term roles (i.e., retirements and displacement) of fossil-fueled power plants in California's electricity system as we move to a high-renewable, low-GHG electricity system, which will include projects like PSEGS.

---

[23] The energy payback time is the time required to produce an amount of energy as great as what was consumed during production, which in the context of a solar power plant includes all of the energy required during construction and operation.

[24] The GHG displacement for the project would be similar to, but not exactly the same as, the amount of energy produced after energy payback is achieved multiplied by the average GHG emissions per unit of energy displaced. The average GHG emissions for the displaced energy over the project life is not known but currently fossil fuel fired power plants have GHG emissions that range from 0.35 MT/MWh CO2E for the most efficient combined cycle gas turbine power plants to over 1.0 MT/MWh for coal fired power plants.

Construction Impacts

Staff concludes that the GHG emission increases from construction activities would not be CEQA significant for several reasons. First, the period of construction would be short-term and the emissions intermittent during that period, not ongoing during the life of the proposed modified project. Second, best practices control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards, would further minimize GHG emissions since the use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. And lastly, these temporary GHG emissions are necessary to create this renewable energy source that would provide electricity with a very low GHG emissions profile, and the construction emissions would be more than offset by the reduction in fossil fuel–fired generation that would be enabled by this proposed modified project. If the project construction emissions were distributed over the estimated 30-year life of the proposed modified project they would only increase the project life time facility GHG emissions rate by 0.002 MT CO2E per MWh.

Electricity System GHG Operational Impacts – David Vidaver

Direct/Indirect Operation Impacts and Mitigation

The proposed PSEGS promotes the state's efforts to move towards a high-renewable, low-GHG electricity system, and therefore reduces both the amount of natural gas used by electricity generation and GHG emissions. It does this in several ways:

- California's Energy Action Plan Loading Order specifies that electrical energy demand be met first by energy efficiency and demand response, followed by employing renewable energy such as would be provided by PSEGS.
- The energy produced by the PSEGS would displace energy from higher GHG-emitting coal- and natural gas-fired generation resources, lowering the GHG emissions from the western United States, the relevant geographic area for the discussion of GHG emissions from electricity generation.
- The dependable capacity provided by the PSEGS would facilitate the retirement/divestiture of resources that cannot meet the Emissions Performance Standard (EPS) or are adversely affected by the SWRCB's policy on OTC.

CALIFORNIA'S ENERGY ACTION PLAN LOADING ORDER

In 2003, the three key energy agencies in California – the California Energy Commission, the California Power Authority (CPA), and the CPUC– came together in a spirit of unprecedented cooperation to adopt an "Energy Action Plan" (EAP) that listed joint goals for California's energy future and set forth a commitment to achieve these goals through specific actions. The EAP is a living document meant to change with time, experience, and need. In 2005 the CPUC and the Energy Commission jointly prepared an Energy Action Plan II to identify further actions necessary to meet California's future energy needs (CEC 2005).

The EAP's overarching goal is for California's energy to be adequate, affordable, technologically advanced, and environmentally-sound. Energy must be reliable – provided when and where needed and with minimal environmental risks and impacts. Energy must be affordable to households, businesses and industry, and motorists – and in particular to disadvantaged customers who rely on California government to ensure that they can afford this fundamental commodity. EAP actions must be taken with clear recognition of cost considerations and trade-offs to ensure reasonably priced energy for all Californians.

The EAP accomplishes these goals in the electricity sector by calling for a "loading order" specifying the priority order for how to balance electricity supply and demand. The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing electrical energy needs. After cost-effective efficiency and demand response, it relies on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, the loading order supports clean and efficient fossil-fired generation.

The Role of the PSEGS in Energy Displacement

California's RPS calls for 33 percent of California's electrical energy to be provided by qualifying renewable energy facilities by the year 2020. The RPS was established by SB 1078 (Sher, Chapter 516, Statutes of 2002), effective January 1, 2003, with revisions to the law as a result of SB 1250 (Perata, Chapter 512, Statutes of 2006), SB 107 (Simitian, Chapter 464, Statutes of 2006), and SB X1 2 (Simitian, Chapter 1, Statutes of 2011, First Extraordinary Session). The RPS originally required California's electric utilities to obtain at least 20 percent of its power supplies from renewable sources by 2010. It now has been expanded to require retail sellers of electricity and local publicly owned electric utilities (POUs) to increase the amount of renewable energy they procure until 33 percent of their retail sales are served with renewable energy by December 31, 2020. Under the law, the Energy Commission is required to certify eligible renewable energy resources that may be used by retail sellers of electricity and POUs to satisfy their RPS procurement requirements, develop an accounting system to verify retail sellers' and POUs' compliance with the RPS, and adopt regulations specifying procedures for enforcement of the RPS for the POUs.

As California moves towards an increased reliance on renewable electrical energy by implementing the RPS, non-renewable electric energy resources will be displaced. A 33 percent RPS is forecasted to require California load-serving entities to procure more than 82,800 GWh of renewable electrical energy in 2024, an increase of roughly 28,300 GWh over current levels.[25]

Given an RPS, renewable electrical energy displaces electricity that would otherwise be produced from coal- and natural gas-fired generation. The construction and operation of the PSEGS would not displace other renewable resources as load-serving entities must meet the renewable energy purchase requirements embodied in the RPS. Even in the

[25] Retail sales requiring renewable procurement are forecasted to be almost 283,300 GWh in 2024 (CEC 2013a); as of January 2013 California is estimated to have procured 54,400 GWh (CEC 2013a)

absence of an RPS, PSEGS would not replace other renewables. The fuel and other variable costs associated with most forms of renewable generation are much lower than for other resources and even where this may not be the case (e.g., selected biofuels) the renewable resource will frequently have a “must-take” contract with a load-serving entity requiring that all of electrical energy produced by the project be purchased by the buyer. Hydroelectric generation is not displaced as it has very low variable costs of production; the variable cost of nuclear generation is much lower than for fossil resources as well.

While the PSEGS would combust some natural gas and thus emit GHGs as part of its operations, it would produce far less GHG emissions (emitting approximately 132[26] lbs CO2/MWh) than the coal- and natural gas-fired resources it would displace. Coal-fired generation requires the combustion of 9,000 – 10,000 Btu/MWh, resulting in more than 1,800 lbs CO2/MWh. Natural gas-fired generation in California requires an average of 8,566 Btu/MWh, yielding approximately 1,000 lbs CO2/MWh (CEC 2011b).[27]

The Role of the PSEGS in Capacity Displacement

The PSEGS would provide up to 500 MW of electrical capacity and associated electrical energy to the grid during early afternoon hours in the summer. Electricity demand in California reaches its peak during mid- to late-afternoon on the hottest weekdays of the summer. Dependable capacity – the amount of capacity that can be counted upon to be available during the peak - is needed to reliably serve loads; the generation fleet, in conjunction with demand response programs, must provide a sufficient amount of dependable capacity to meet demand on the highest load day of the year.[28] Load-serving entities in the California Independent System Operator (Cal ISO) control area, for example, are required by the Cal ISO to procure dependable capacity in amounts determined by their peak load forecast.

While the PSEGS’s dependable capacity value would depend upon its exact performance, its ability to sustain output even when solar irradiance is reduced due to cloud cover, and thus provide energy during extreme peak hours would mean a higher value than would otherwise be the case. Although the dependable capacity can be augmented by the natural gas-fired auxiliary boiler, if operating period fuel use exceeds a “de minimus” level defined in the RPS regulations, the facility would no longer qualify as a renewable facility for purposes of the RPS.

The dependable capacity provided by the PSEGS would assist in replacing that lost due to the EPS and the State Water Resources Control Board’s (SWRCB) OTC policy, both discussed more fully below.

---

[26] Derived from Greenhouse Gas Table 3 Estimated PSEGS Operating Period Greenhouse Gas Emissions

[27] The PSEGS would displace resources with a higher than average heat rate during most hours, as the most expensive (least efficient) resources would be displaced.

[28] This is usually the hottest weekday in the summer, when residential and commercial cooling loads are at their highest.

Replacement of High GHG-Emitting Generation

High GHG-emitting resources, such as coal, are effectively prohibited from entering into new long-term contracts for California electricity deliveries as a result of the Emissions Performance Standard adopted in 2007 pursuant to SB 1368. Between now and 2020, 1,549 MW of coal-fired generation capacity under contract will have to reduce GHG emissions or be replaced; these contracts are presented in **Greenhouse Gas Table 4**.

Greenhouse Gas Table 4
Expiring Long-term Contracts with Coal-fired Generation 2009 – 2020

Utility	Facility	Contract Expiration	MW
Department of Water Resources	Reid Gardner	2013 [1]	213
SDG&E	Boardman	2013	84
SCE [2]	Four Corners	2016	720
Turlock Irrigation District	Boardman	2018	55
LADWP	Navajo	2019	477
		TOTAL	**1,549**

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.
Notes:
1. Contract not subject to Emission Performance Standard, but the Department of Water Resources has stated its intention not to renew or extend.
2. The sale of SCE's share of Four Corners to Arizona Public Service has been approved by the CPUC and is awaiting FERC approval.

Retirement of Generation Using Once-Through Cooling

The State Water Resource Control Board's (SWRCB) policy on cooling water intake at coastal power plants has led to the retirement and replacement of several plants that used OTC. Numerous others are likely to retire on or prior to assigned compliance dates,[29] some of which will require replacement.[30] The units with compliance dates on or before the end of 2020 are presented in **Greenhouse Gas Table 5**.

[29] Most of the OTC units are aging facilities, for which extensive retrofits will be uneconomical. While compliance using operational and structural controls is allowed, the ability of units to comply in this manner and still operate in a fashion that yields a sufficient revenue stream is questionable.

[30] The California ISO, CPUC and the Energy Commission are studying amount of OTC capacity that will require replacement.

Greenhouse Gas Table 5
OTC Units with SWRCB Compliance Dates on or before December 31, 2020[31]

Plant Name & Unit	Local Reliability Area	Capacity (MW)
Alamitos 1 – 6	LA Basin	2,010
El Segundo 3 & 4	LA Basin	670
Encina 1 – 5	San Diego	950
Huntington Beach 1 & 2	LA Basin	430
Mandalay 1 & 2	Ventura	436
Morro Bay 3 & 4	None	650
Moss Landing 6 & 7	None	1,510
Moss Landing 1 & 2	None	1,020
Ormond Beach 1 & 2	Ventura	1,516
Pittsburg 5 & 7 [2]	SF Bay	1,311
Redondo Beach 5 – 8	LA Basin	1,356
Total		**11,859**

Notes:
Pittsburg Unit 7 (682 MW) does not use once-through cooling but would be required to shut down if Units 5 and 6 retire.

CLOSURE AND DECOMMISSIONING – JACQUELYN LEYVA RECORD

Eventually PSEGS would close, either at the end of its useful life or due to some unexpected situation such as a natural disaster or catastrophic facility breakdown. When the facility closes, all sources of air emissions would cease and thus impacts associated with GHG emissions would no longer occur. The only other expected, albeit temporary, GHG emissions would be equipment exhaust (off-road and on-road) from dismantling activities. These activities would be of much a shorter duration than construction of the proposed modified project, equipment used to dismantle the facility are assumed to have lower comparative GHG emissions due to technology advancement during the intervening years, and this equipment would be required to be controlled in a manner at least equivalent to that required during construction. It is assumed that the beneficial GHG impacts of this facility, displacement of fossil fuel–fired generation, would be replaced by the construction of newer more efficiency renewable energy or other low GHG generating technology facilities. Also, the recycling of the facility components (steel, concrete, etc.) could indirectly reduce GHG emissions from decommissioning activities. Therefore, while there would be temporary adverse GHG CEQA impacts during decommissioning, they are determined to be less than significant.

CUMULATIVE IMPACTS

Cumulative impacts are defined as “two or more individual effects which, when considered together, are considerable or...compound or increase other environmental impacts” (CEQA Guidelines § 15355). “A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts” (CEQA Guidelines § 15130[a][1]). Such impacts may

[31] Greenhouse Gas Table 5 does not include OTC units that retired prior to January 1, 2012, resources with compliance dates through 2020 that have already been slated for replacement (e.g., LADWP units at Haynes and Scattergood), or units with post-2020 compliance dates (the remaining units at Haynes and Scattergood, LADWP’s Harbor combined cycle, and the nuclear facilities at San Onofre [which Southern California Edison announced on June 7, 2013 that they would close it rather than repair it] and Diablo Canyon)

be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This entire assessment is a cumulative impact assessment. The proposed modified project alone would not be sufficient to change global climate, but would emit GHGs and therefore has been analyzed as a potential cumulative impact in the context of existing GHG regulatory requirements and GHG energy policies.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The PSEGS, as a solar energy generation project, is exempt from the mandatory GHG emission reporting requirements for electricity generating facilities as currently required by the ARB for compliance with the California Global Warming Solutions Act of 2006 (AB 32 Núñez, Statutes of 2006, Chapter 488, Health and Safety Code sections 38500 et seq.) (ARB 2008a).

The PSEGS, as a renewable energy generation facility, is determined by rule to comply with the Greenhouse Gas Emission Performance Standard requirements of SB 1368 (Chapter 11, Greenhouse Gases Emission Performance Standard, Article 1, Section 2903 [b][1]).

NOTEWORTHY PUBLIC BENEFITS

GHG related noteworthy public benefits include the construction of renewable and low-GHG emitting generation technologies and the potential for successful integration into the California and greater WECC electricity systems. Additionally, the PSEGS project would contribute to meeting the state’s AB 32 goals.

RESPONSE TO ~~AGENCY AND PUBLIC~~ COMMENTS

Staff has not received GHG comments.

PROPOSED CONDITIONS OF CERTIFICATION

No conditions of certification related to greenhouse gas emissions are proposed. The project owner would comply with mandatory ARB GHG emissions reporting regulations (California Code of Regulations, tit. 17, Subchapter 10, Article 2, Sections 95100 et. seq.) and/or future GHG regulations formulated by the U. S. EPA or the ARB, such as GHG emissions cap-and-trade requirements.

CONCLUSIONS

The PSEGS would emit considerably less GHGs than existing power plants and most other generation technologies, and thus would contribute to continued improvement of the overall western United States, and specifically California, electricity system GHG emission rate average. The proposed project would lead to a net reduction in GHG emissions across the electricity system that provides energy and capacity to California.

Thus, even though PSEGS would emit more GHGs than the approved PSPP, staff concludes that the proposed project's operation would result in a cumulative overall reduction in GHG emissions from the state's power plants and that any short-term impacts would be less than significant.

Staff concludes that GHG emissions typical from construction and decommissioning activities would not create significant impacts under CEQA for several reasons. First, the periods of construction and decommissioning would be short-term and not ongoing during the life of the proposed project. Second, the best practices control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards, would further minimize GHG emissions since the use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. Finally, the construction and decommissioning emissions are miniscule when compared to the reduction in fossil-fuel power plant GHG emissions during project operation. For all these reasons, staff concludes that the short-term emission of greenhouse gases during construction would be sufficiently reduced and would be offset during proposed project's operating period and would, therefore, not create a significant impact under CEQA.

The PSEGS, as a renewable energy generation facility, is determined by rule to comply with the Greenhouse Gas Emission Performance Standard requirements of SB 1368 (Title 20, Greenhouse Gases Emission Performance Standard, Section 2900 et. seq.). The project is not subject to the requirements of SB 1368 (Greenhouse Gasses Emission Performance Standard; Cal. Code Reg., tit. 20, § 2900 et. Seq.) and the Emission Performance Standard; however, it would nevertheless meet the Emission Performance Standard.

REFERENCES

ARB 2006 – Air Resources Board. AB 32 Fact Sheets, California Global Warming Solutions Act of 2006 and Timeline. www.arb.ca.gov/cc/cc.htm. September 2006.

ARB 2008a – Air Resources Board. Instructional Guidance for Mandatory GHG Emissions Reporting. http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-guid/ghg-rep-guid.htm. December 2008

ARB 2008b – California Air Resource Board. Climate Change, Proposed Scoping Plan a Framework for Change, Pursuant to AB 32. Released October 2008, approved December 2008. http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

ARB 2011 – California Air Resources Board. California Greenhouse Gas Inventory for 2000-2009 – by Category as Defined in the Scoping Plan. October, 26, 2011. http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_00-09_2011-10-26.pdf

CalEPA 2006 – California Environmental Protection Agency. Climate Action Team Report to Governor Schwarzenegger and the Legislature. March, 2006. http://www.climatechange.ca.gov/climate_action_team/reports/2006report/2006-04-03_FINAL_CAT_REPORT.PDF

CCCC 2006 – California Climate Change Center. Our Changing Climate – Assessing the Risks to California. CEC-500-2006-077. July 2006. http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.PDF

CEC 1998 – California Energy Commission. 1997 Global Climate Change, Greenhouse Gas Emissions Reduction Strategies for California, Volume 2, Staff Report. 1998. http://www.climatechange.ca.gov/publications/97GLOBALVOL2.PDF

CEC 2003 – California Energy Commission. 2003 Integrated Energy Policy Report. December 2003. http://www.energy.ca.gov/reports/100-03-019F.PDF

CEC 2007 – California Energy Commission. 2007 Integrated Energy Policy Report – Scenario Analysis of California's Electricity System. http://www.energy.ca.gov/2007_energypolicy/documents/index.html. 2007.

CEC 2009a – California Energy Commission. Committee Report (08-GHG OII-01). Committee Guidance On Fulfilling California Environmental Quality Act Responsibilities For Greenhouse Gas Impacts In Power Plant Siting Applications. March 2009. http://www.energy.ca.gov/ghg_powerplants/documents/index.html.

CEC 2009b – California Energy Commission. Framework for Evaluating Greenhouse Gas Implications of Natural Gas–Fired Power Plants in California, CEC-700-2009-009, MRW and Associates. May 27, 2009. http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF

CEC 2009c – California Energy Commission, California Energy Demand 2010-2020 Adopted Forecast. December 2009. http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF

CEC 2009d – California Energy Commission, 2009 Integrated Energy Policy Report. December 16, 2009. http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

CEC 2009e - California Energy Commission. The Future Is Now: An Update on Climate Change Science Impacts and Response Options for California. May. http://www.energy.ca.gov/2008publications/CEC-500-2008-071/CEC-500-2008-071.PDF

CEC 2010 – California Energy Commission, Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast (CEC-200-2010-001-D, January, 2010), http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html

CEC 2011a – California Energy Commission, Renewable Power in California: Status and Issues, CEC-150-2011-002-LCF-REV1, http://www.energy.ca.gov/2011publications/CEC-150-2011-002/CEC-150-2011-002-LCF-REV1.pdf

CEC 2011b – California Energy Commission, Thermal Efficiency of Gas-Fired Generation in California, August 2011, CEC-200-2011-008, http://www.energy.ca.gov/2011publications/CEC-200-2011-008/CEC-200-2011-008.pdf

CEC 2013a – California Energy Commission. Staff Update Report, New Renewable Generation Needed to Comply with Policy Goal: Update for 2022 Planning, March 2013, CEC-200-2013-001, http://www.energy.ca.gov/2013publications/CEC-200-2013-001/CEC-200-2013-001.pdf

CPUC 2008 – California Public Utilities Commission. Final Opinion on Greenhouse Gas Regulatory Strategies, Joint Agency proposed final opinion, publication # CEC-100-2008-007-D. Posted: September 12, 2008. http://www.energy.ca.gov/2008publications/CEC-100-2008-007/CEC-100-2008-007-D.PDF

Greenpeace 2005 – Concentrated Solar Thermal Power – Now! Authors: Rainer Aringhoff and Georg Brakmann ESTIA, Dr. Michael Geyer (IEA SolarPACES), and Sven Teske Greenpeace International. September 2005. http://www.greenpeace.org/raw/content/international/press/reports/Concentrated-Solar-Thermal-Power.pdf.

IPCC 2007a - Intergovernmental Panel on Climate Change. Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the IPCC. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html.

IPCC 2007b - Intergovernmental Panel on Climate Change. Climate Change 2007: Synthesis Report Summary for Policymakers. November 2007. http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr_spm.pdf.

NASA 2013 – National Aeronautics and Space Administration. Earth website page. Accessed March 2013. http://www.nasa.gov/topics/earth/features/2012-temps.html

U.S.EPA 2009c – United States Environmental Protection Agency. Fact Sheet — Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. September 30, 2009.

U.S.EPA 2010a - United States Environmental Protection Agency. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. http://www.epa.gov/NSR/documents/20100413final.pdf. Accessed June 2010.

Wohlfahrt. et al. 2008 – Georg Wohlfahrt, Lynn F. Fenstermaker, and John A. Arnone III. Large annual net ecosystem CO_2 uptake of a Mojave Desert ecosystem. Global Change Biology, 2008 (14).

ACRONYMS

AB	Assembly Bill
ARB	California Air Resources Board
CAA	Clean Air Act
CalEPA	California Environmental Protection Agency
Cal ISO	California Independent System Operator
CCCC	California Climate Change Center
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO2E	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
EIR	Environmental Impact Report
EPS	Emission Performance Standard
FSA	Final Staff Assessment
GCC	Global Climate Change
GHG	Green House Gas
GWh	Gigawatt-hour
GWP	Global Warming Potential
HFC	Hydrofluorocarbons
IEPR	Integrated Energy Policy Report
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
LADWP	Los Angeles Department of Water and Power
LRAs	Local Reliability Areas
MT	Metric tonnes
MW	Megawatts
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates
NOx	Oxides of Nitrogen or Nitrogen Oxides
OII	Order Initiating an Informational
OTC	Once-Through Cooling
PFC	Perfluorocarbons
POU	Publicly Owner Utility
PSD	Prevention of Significant Deterioration
PSEGS	Palen Solar Electric Generating System
PSPP	Palen Solar Power Plant
QFER	Quarterly Fuel and Energy Report
RPS	Renewables Portfolio Standard
SB	Senate Bill
SF_6	Sulfur hexafluoride
SWRCB	State Water Resource Control Board
U.S. EPA	United States Environmental Protection Agency
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

Declarations

&

Resumes

DECLARATION OF
Jacquelyn Leyva Record

I, **Jacquelyn Leyva Record,** declare as follows:

1. I am presently employed by the California Energy Commission in the Engineering Office of the Siting, Transmission and Environmental Protection Division as a Air Resources Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony on **Air Quality** for the **Palen Solar Electric Generating System Final Staff Assessment,** based on my independent analysis of the Application for Certification and supplement hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: Aug 1, 2013 Signed: Jacquelyn Leyva Record

At: Sacramento, California

(925) 324-1173 cell
jlrecord03@gmail.com

Jacquelyn Leyva Record

Experience

March '09 – Present **CA Energy Commission** **Sacramento, CA**

Air Resources Engineer

- Currently authoring staff assessment analyses for the technical area of air quality for the Engineering and Siting Division permitting power plant projects over 50 MW in the state of CA. Worked on renewable ARRA funding projects along with natural gas power projects.
- Reviewing emission compliance reports
- Authored staff analyses for project amendments
- Trained in CEQA and NEPA analysis, along with AERMOD air modeling.

August '08 – March '09 **ERRG, Inc.** **Martinez, CA**

Engineering Assistant

- Assisted with both technical and field duties for a variety of environmental investigations.
- Assisted on an environmental site assessment, preliminary assessments (PA), site inspections, and remedial investigations feasibility studies.
- Field duties performed include groundwater sampling and air sampling

June '07 – March '08 **Tetra Tech EC, Inc** **Santa Ana, CA**

Engineering Assistant Intern

- Working on various Department of Defense projects in environmental engineering.
- Helped assist in 5 year review of remediation approaches.
- Helping assist with a commercial project creating a water reuse/recycle treatment plant.

June '05 – September '05 **SF Regional Water Board** **Oakland, CA**

Contract Work – Special Project

- Wrote a memorandum regarding total petroleum hydrocarbons showing up as false positives in submitted quarterly monitoring reports for NPDES FUEL permit.
- Researched various EPA methods of testing for VOC, and Fuel constituents in water.
- Communicated with consultants from Weiss Associates and state funded laboratories to come to a conclusion for memorandum.
- Site inspections, site reports.

Education

2003-June 2008 University of California Irvine Irvine, CA

- B.S., Chemical Engineering
- MAES (Mexican American Engineers and Scientists) - Vice Chair 2004-2005
- CAMP summer science program participant 2003

June 1999 – September 2003 Las Lomas High School Walnut Creek, CA

- High School Diploma
- Life time member of CSF (California Scholarship Federation).