AIR QUALITY

Prepared by William Walters, P.E.

SUMMARY OF CONCLUSIONS

U.S. Bureau of Land Management (BLM) and Energy Commission staff (hereinafter jointly referred to as "staff") find that with the adoption of the attached conditions of certification the proposed Ivanpah Solar Electric Generating System (ISEGS) project would comply with all applicable laws, ordinances, regulations, and standards (LORS) and would not result in any significant air quality-related CEQA impacts. Conditions of Certification referred to herein serve the purpose of both the Energy Commission's Conditions of Certification for purposes of the California Environmental Quality Act (CEQA) and BLM's Mitigation Measures for purposes of the National Environmental Policy Act (NEPA).

Staff have concluded that the project would not have the potential to exceed PSD emission levels during direct source operation and the facility is not considered a major stationary source with potential to cause significant NEPA air quality impacts. However, without adequate fugitive dust mitigation, the project would have the potential to exceed the General Conformity PM10 applicability threshold during construction and operation, and could cause potential localized exceedances of the PM10 NAAQS during construction and operation. This potential exceedance of federal air quality standards would be considered a direct, adverse significant impact under NEPA. This impact would be less than significant with the proposed construction and operation mitigation measures controlling fugitive dust.

The ISEGS project would emit substantially reduced greenhouse gas (GHG)[1] emissions per megawatt-hour produced than fossil fueled generation resources in California. The project is not subject to the requirements of SB 1368 (Perata, Chapter 598, Statutes of 2006) and the Emission Performance Standard, but would nevertheless meet the Emission Performance Standard.

INTRODUCTION

On August 28, 2007, BrightSource Energy (applicant) submitted an Application for Certification (AFC) to construct and operate ISEGS in the Mojave Desert region near the border of California and Nevada in San Bernardino County. The applicant proposes to develop this project in three phases, which together would produce approximately 400-megawatt (MW) of electrical power. The project would include heliostat mirror fields, spread over approximately 4,065 acres, focusing solar energy on power tower receivers producing steam for turbine generators.

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

This analysis evaluates the expected air quality impacts from the emissions of criteria air pollutants from both the construction and operation of the ISEGS project. Criteria air pollutants are defined as air contaminants for which the state and/or federal governments have established an ambient air quality standard to protect public health.

The criteria pollutants analyzed 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 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 project are discussed in an Appendix Air-1 and analyzed in the context of cumulative impacts.

In carrying out this analysis, the California Energy Commission (Energy Commission) staff evaluated the following four major points:

- whether the ISEGS project is likely to conform with applicable federal, state, and Mojave Desert Air Quality Management District (District) air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- whether the ISEGS project 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);
- whether mitigation measures proposed for the project are adequate to lessen potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).
- whether the ISEGS project would exceed NEPA air quality analysis thresholds, before or after implementation of recommended mitigation measures.

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 ISEGS are summarized in **Air Quality Table 1**. Staff's analysis examines the project's compliance with these requirements summarizes the applicable LORS.

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 is delegated to MDAQMD. Prevention of Significant Deterioration (PSD) requires major sources or major modifications to major sources to obtain permits for attainment pollutants. The ISEGS project is a new source that has a rule listed emission source thus the PSD trigger levels are 100 tons per year for NOx, VOC, SO_2, PM2.5 and CO. This project's proposed emissions are below NSR and PSD applicability thresholds.
40 CFR Part 60	New Source Performance Standards (NSPS), Subpart Da Standards of Performance for Electricity Steam Generation Units. Establishes emission standards and monitoring/recordkeeping requirements for units with greater than 250 MMBtu/hr heat input. Subpart Db Standards of Performance for Electricity Steam Generation Units. Establishes emission standards and monitoring/recordkeeping requirements for units with greater than 100 MMBtu/hr heat input. Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Establishes emission standards for compressions ignition internal combustion engines, including emergency fire water pump engines.
40 CFR Part 93 General Conformity	Requires determination of conformity with State Implementation Plan for Projects requiring federal approvals it project annual emissions are above specified levels.
State	
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with 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 fire water pump engines.
Local (Mojave Desert Air Quality Management District, MDAQMD)	
Rule 201 and 203 Permits Required	Required a Permit to Construct before construction of an emission source occurs. Prohibits operation of any equipment that emits or controls air pollutant without first obtaining a permit to operate.
Rules 401, 402, 403, and 403.2 Nuisance, Visible Emissions, Fugitive Dust	Limits the visible, nuisance, and fugitive dust emissions and would be applicable to the construction period of the project.
Rule 404 Particulate Matter - Concentration	Limits the particulate matter concentration from stationary source exhausts.
Rule 900 Standard of Performance for New Stationary Source	Incorporates the Federal NSPS (40 CFR 60) rules by reference.
Regulation XII – Federal Operating Permits	Requires new or modified major facilities, or facilities that trigger NSPS, Acid Rain or other federal air quality programs obtain a Title V federal operating permit.
Rule 1210 – Acid Rain	Requires facilities subject to the federal Acid Rain program obtain permits and comply with emissions and monitoring provisions.

Applicable LORS	Description
Rule 1303 New Source Review	Specifies BACT/Offsets technology and requirements for a new emissions unit that has potential to emit any affected pollutants.
Rule 1306 Electric Energy Generating Facilities	Describes actions to be taken for permitting of power plants that are within the jurisdiction of the Energy Commission.

SETTING

CLIMATE AND METEOROLOGY

The project is located in the southern California Mojave Desert, about three and one-half miles west of the California-Nevada border at approximately 2,800 to 3,400 feet above sea level. Relatively high daytime temperatures, large variations in relative humidity, large and rapid diurnal temperature changes, occasional high winds, and sand, dust, and thunderstorms characterize the climate of the Mojave Desert area. The aridity of the region is influenced by a sub-tropical high-pressure system typically off the coast of California and topographical barriers that effectively block the flow of moisture to the region. Seasonally, the precipitation totals in the area range from lows of 0.5 inch in the spring to as high as 8 inches in the winter.

The most recent meteorological (weather) data, collected at the Jean, Nevada monitoring station 16 miles northeast of the project site, was for 2001 through 2002. The measured wind data are graphically represented by quarterly wind roses, provided in the AFC Figures 5.1-1 and 5.1-2 (BSE2007a). These wind roses show that for most of the year, the winds are from the west-southwest, although between November through March, winds are predominately from the northeast. Mixing heights in the area, which represent the altitudes where different air masses mix together, are estimated to be on average 230 feet (70 meters) in the morning to as high as 5,250 feet (1,600 meters) above ground level in the afternoon.

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 AAQS, established by the California Air Resources Board, are typically lower (more protective) than the federal AAQS, which are established by the United States Environmental Protection Agency (U.S. EPA). The state and federal air quality standards are listed in **Air Quality Table 2**. As indicated 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 annual averages. 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 $\mu g/m^3$, respectively).

In general, an area is designated attainment if the concentration of a particular air contaminant does not exceed the standard. Likewise, an area is designated non-attainment for an air contaminant if that contaminant standard is violated. Where not enough ambient data are available to support designation as either attainment or non-attainment, the area can be designated as unclassified. An unclassified area is normally 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.

ISEGS is located in the Mojave Desert Air Basin (MDAB) and is under the jurisdiction of the Mojave Desert Air Quality Management District (MDAQMD). This area is designated as moderate nonattainment for the state ozone standard, nonattainment for both the state and the federal PM10 standards, attainment for federal ozone standard, and attainment or unclassified for the state and federal CO, NO_2, SO_2, and PM2.5 standards. **Air Quality Table 3** summarizes the area's attainment status for various applicable state and federal standards.

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	—	0.18 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	—	0.25 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 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%.

Source: ARB 2009a.

Air Quality Table 3
Federal and State Attainment Status
Mojave Desert Air Basin [a]

Pollutant	Attainment Status [b]	
	Federal	State
Ozone	Attainment	Moderate Nonattainment
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
PM10	Nonattainment	Nonattainment
PM2.5	Attainment	Attainment

Source: ARB 2009b, U.S. EPA 2009a.
a Attainment status for the site area only, not the entire MDAB.
b Attainment = Attainment or Unclassified.

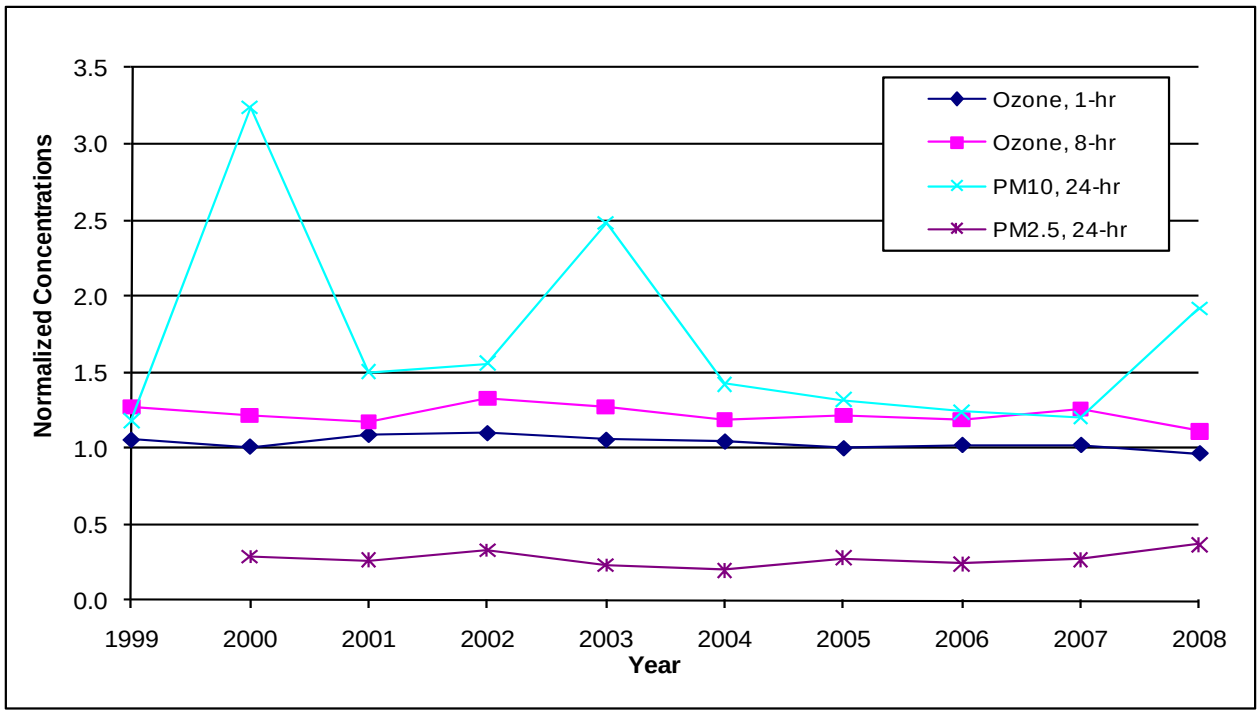
Ambient air quality monitoring data for ozone, PM10, PM2.5, CO, NO_2, and SO_2, compared to most restrictive applicable standards for the years between 2004 through 2008 (the last year that the complete annual data is currently available) at the most representative monitoring stations for each pollutant are shown in **Air Quality Table 4** and the 1-hour and 8-hour ozone, and 24-hour PM10 data for the years 2004 through 2008 are shown in **Air Quality Figure 1**. All ozone, PM10, PM2.5, and NOx (up through 2006) data shown are from the Jean, Nevada, monitoring station that is located approximately 17 miles northwest of the project site. All CO data are from the Barstow monitoring station that is located approximately 100 miles west southwest of the project site. All SOx data are from the Trona Athol and Telegraph monitoring station that is located approximately 110 miles west northwest of the project site. Besides the Jean monitoring station, which provides reasonably close ozone, NOx, and particulate monitoring data, available monitoring stations for CO or SOx are either located a hundred miles or more away from the site, or in the case of Las Vegas are otherwise not representative as an urban location. Therefore, staff has chosen other more remote Mojave Desert Air Basin monitoring locations, Barstow and Trona, to represent the site conditions. However, while staff expects that the background ambient concentrations for both of these pollutants to be relatively low at the project site, there is a reduced overall confidence in the representativeness of these monitoring stations.

Air Quality Table 4
Criteria Pollutant Summary
Maximum Ambient Concentrations (ppm or µg/m^3)

Pollutant	Averaging Period	Units	2004	2005	2006	2007	2008	Limiting AAQS
Ozone	1 hour	ppm	0.094	0.090	0.092	0.092	0.087	0.09
Ozone	8 hours	ppm	0.083	0.085	0.083	0.088	0.078	0.07
PM10 [a]	24 hours	µg/m^3	71	66	62	60	96	50
PM10 [a,b]	Annual	µg/m^3	15.9	17.3	12.1	12.7	12.7	20
PM2.5 [a,c]	24 hours	µg/m^3	7.3	10.2	9.0	11.1	12.9	35
PM2.5 [a,b]	Annual	µg/m^3	3.49	3.78	3.52	4.08	4.52	12
CO	1 hour	ppm	1.6	3.3	3.5	1.4	1.4	20
CO	8 hours	ppm	1.18	1.34	1.19	0.70	1.23	9.0
NO_2	1 hour	ppm	0.032	0.039	0.036	ND	ND	0.18
NO_2	Annual	ppm	0.0035	0.0039	0.0035	ND	ND	0.03
SO_2	1 hour	ppm	0.019	0.0188	0.033	0.014	0.036	0.25
SO_2	24 hours	ppm	0.005	0.004	0.005	0.004	0.005	0.04
SO_2	Annual	ppm	0.001	0.001	0.001	0.001	0.001	0.03

Source: ARB 2008, ARB 2009c, U.S. EPA 2009b
ND – no data
Notes:
[a] Exceptional PM concentration events, such as those caused by windstorms are excluded in the data presented.
[b] Annual average data is federal data and may not exactly represent California annual average.
c The U.S. EPA database used for retrieval of the PM2.5 data did not allow direct determination of the calculated 98th percentile, which is the basis of the standard, so the closest proxy (third highest values) are presented.

Air Quality Figure 1
1999-2008 Historical Ozone and PM Air Quality Data - Jean, Nevada



Source: US.EPA 2009b
Note: 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 1-hour ozone concentration in 2005 is 0.090 ppm/0.09 ppm standard = 1.0.

Ozone

The area is classified attainment of the federal 8-hour ozone standard and is classified as nonattainment of the state ozone standards. The ambient data shown in **Air Quality Table 3** indicates that 8-hour concentrations near the site (Jean, Nevada) exceed the recently revised federal 8-hour ozone standard (0.075 ppm). However, the values shown are peak values that correspond to the state standard. The federal standard is based on the fourth highest 8-hour concentration in a year averaged over three years.

The current federal 8-hour ozone attainment status was determined in 2004, was based on the former 8-hour ozone standard of 0.08 ppm, and would have considered state lines and monitoring station locations, where the data shown is from Nevada, not California. The State of California has recommended to U.S. EPA that the northeast portion of San Bernardino County be designated as nonattainment of the new federal ozone standard (ARB 2009d) with an 8-hour ozone design value of 0.080 ppm for the northeast portion of San Bernardino County. U.S. EPA has not yet commented on this recommendation. The revised federal 8-hour ozone standard attainment/nonattainment designations are scheduled to be completed by March 12, 2010.

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. **Air Quality Figure 1** shows that the maximum 1-hour ozone

concentrations monitored near the site in Jean, Nevada, have been relatively stable over the past ten years and are just over the state's 1-hour standard for most years from 1999 to 2008. The maximum 8-hour ozone concentrations also have been relatively stable over the past ten years but are somewhat higher in relation to the AAQS than the 1-hour ozone levels, hovering between 1.2 to 1.4 times the California 8-hour ozone standard since 1999.

The Air Resources Board (ARB) report: *Second Triennial Review of the Assessment of the Impacts of Transported Pollutants on Ozone Concentrations in California* (ARB 1996) provided the following observations regarding ozone violations in the Mojave Desert area:

- The ozone and ozone precursors from the South Coast Air Basin contribute overwhelmingly to ozone violations in the Mojave Desert Air Basin.
- There are days when a combination of local emissions and transported ozone or precursors contribute to the violations of 1-hour ozone standards,
- There is a possibility that on at least one day of the year the violations of the 1-hour ozone standards are the direct result of local source emissions.

However, staff notes that in the area of the project site at the far eastern end of the MDAB there is also the potential for ozone transport from the much closer Las Vegas area. However, regardless of the source, it is clear that the main source of the ozone concentrations encountered in the project site area are primarily the result of pollutant transport from urban areas.

Nitrogen Dioxide

The entire air basin is classified attainment of the state 1-hour and federal annual nitrogen dioxide (NO_2) standards. The NO_2 levels monitored in Jean, Nevada, are no more than 25 percent of the most stringent NO_2 ambient air quality standard. Approximately 90 percent of the 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 NO emissions near the ground but lacking substantial photochemical activity (sun light), oxidation of NO to NO_2 and NO_2 levels remain 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 at levels that might approach the 1-hour ambient air quality standard.

Carbon Monoxide

The area is classified attainment of the state and federal 1-hour and 8-hour carbon monoxide (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.

Particulate Matter (PM10)

The area is nonattainment for both the state and the federal PM10 standards. PM10 can be emitted directly as fugitive dust or combustion particulates, or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SOx and VOC from combustion sources, and ammonia (NH_3) from human and animal wastes or combustion NOx control equipment can, given the right meteorological conditions, form particulate matter known as nitrates (NO_3), sulfates (SO_4), and organic compounds. These pollutants are known as secondary particulates, because they are not directly emitted but are formed through complex chemical reactions between directly emitted pollutants in the atmosphere.

Air Quality Figure 1 indicates that the state 24-hour ambient air quality standard for PM10 was exceeded every year from 1999 to 2008, with highs close to three and a half times the state 24-hour PM10 standard.

Fine Particulate Matter (PM2.5)

Fine particulate matter, or PM2.5 (particulate matter less than 2.5 microns in diameter), is derived either mainly from 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. Some PM2.5 emissions come from fugitive dust sources such as unpaved roads and construction sites.

The Mojave Desert Air Basin in the area of the project site is classified as attainment or unclassified for both the state and the federal PM2.5 air quality standards, but as noted previously the area is not in attainment of the state and federal PM10 standards. This divergence indicates that the ambient particulate matter levels are most likely due to localized fugitive dust sources, such as vehicles travel on unpaved roads, agricultural operations, or wind-blown dust.

Sulfur Dioxide

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.

Nitrates and Sulfates

PM nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of NOx and ammonia. NOx, as emitted from combustion sources, is mainly in the form of nitric oxide (NO). NO converts to NO_2 primarily by reacting with ozone in the ambient air and sunlight. The formed NO_2 can convert back to NO, which sustains the ozone formation reactions. NO_2 can also form organic nitrates, or be reduced to nitric acid by available hydroxyl radicals in the ambient air. Nitric acid reacts with ammonia in ambient

air to form ammonium nitrate. Ammonium nitrate, in its particulate form, can remain suspended in the ambient air and/or be transported long distance downwind as PM2.5. Ammonium nitrate, under certain conditions of heat and humidity, breaks down to NOx and starts a new ozone cycle again.

PM sulfate (mainly ammonium sulfate) is formed in the atmosphere from the oxidation of SO_2 and subsequent neutralization by ammonia in the atmosphere. The oxidation of SO_2 depends on many factors, which include the availability of sulfur, hydroxyl, hydroperoxy and methylperoxy radicals, and atmospheric humidity.

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 monitoring stations within the Mojave Desert.

Air Quality Table 5
Staff Recommended Background Concentrations (µg/m^3)

Pollutant	Averaging Time	Recommended Background	Limiting Standard	Percent of Standard
NO_2	1 hour	73.3	339	22%
	Annual	7.3	57	13%
PM10	24 hour	96	50	192%
	Annual	12.7	20	64%
PM2.5	24 hour	12.9	35	39%
	Annual	4.5	12	38%
CO	1 hour	4,025	23,000	18%
	8 hour	1,367	10,000	14%
SO_2	1 hour	94.3	655	14%
	24 hour	13.1	105	12%
	Annual	2.7	80	3%

Source: ARB 2008, ARB 2009c, U.S. EPA 2009b and Energy Commission Staff Analysis
Note: PM2.5 24-hour data shown in **Air Quality Table 4** are 99th percentile values; however, the standard is based on the three year average of the 98th percentile, so the background concentration used is somewhat conservative.

Where possible, staff prefers that the recommended background concentrations come from nearby monitoring stations with similar characteristics. For this project the Jean monitoring station (ozone, PM10, PM2.5, and NO_2 [up to 2006]) is located reasonably close to the project site and should be fairly representative of the project site. The Barstow (CO) monitoring station is located in a more populated area and may provide conservatively high background concentrations for the project site. The Trona (SO_2) monitoring station, while located in a more remote area has two very large nearby emission sources of SOx (Searles Valley Minerals and Ace Cogeneration Company) so this monitoring station location should also provide representative or conservative SOx background concentrations for the project site.

The background 24-hour concentrations for PM10 are above the most restrictive existing ambient air quality standards, while the background concentrations for the other pollutants and averaging times are all below the most restrictive existing ambient air quality standards.

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

PROJECT DESCRIPTION

The proposed 400-MW project includes three solar concentrating thermal power plants, based on distributed power tower and heliostat mirror technology, in which heliostat (mirror) fields focus solar energy on power tower receivers near the center of each heliostat array. ISEGS 1 and 2, are designed to provide 100 MW of electricity and would occupy approximately 914 acres and 921 acres respectively; the 200-MW phase, ISEGS 3, would require occupy approximately 1,843 acres. All three phases would share an administration building, an operation and maintenance building, and a substation. Another 316 acres is needed for construction staging activities. Established dirt roads account for an additional five acres. ISEGS total project footprint amounts to approximately 4,065 acres (approximately 6.4 square miles).

Each plant includes a natural gas-fired steam boiler equipped with a low-NOx burner/air recirculation system to maintain NOx emissions below 9 ppm. These boilers provide thermal input to the turbine during the morning start-up cycle and during transient cloudy conditions. The operation of these boilers would not exceed four hours each day and 5 percent of the facility annual's heat input from the sun. To provide fuel to these new boilers, natural gas would be supplied to the site through a new, proposed six-mile long distribution pipeline ranging from 4 to 6 inches in diameter. From the Kern River Gas Transmission pipeline, the pipeline would extend 0.5 miles south to the northern edge of Ivanpah 3. From ISEGS 3, a supply line would extend northwest into the Ivanpah 3 power block. The main pipeline would continue along the eastern edge of Ivanpah 2 to another metering station at its southeastern corner. Again, a branch supply line would extend northwestwards into the center of the Ivanpah 2 power block. From that station, the pipeline would follow the paved access road from Colosseum Road past the administration/warehouse building to the Ivanpah 1 power block.
Project steam cycle cooling needs would be provided by air cooled condensers (ACCs) at each of the three plants, which will minimize water use substantially. The applicant is currently proposing the use of groundwater from wells just east of Ivanpah 2, which will be stored in tanks with underground pipelines constructed to connect to the three plants. Process wastewater will treated onsite and recycled for use at each of the three plants, and domestic wastewater will be disposed in a septic tank and an onsite leach field. Therefore, no industrial wastewater or sewer pipeline is proposed to be constructed.

The project would include other operating emission sources for operation and maintenance of the facility. Each plant also includes a diesel-fired 240-horsepower (hp)

fire pump engine (3 total at the site) and a 3,750-hp emergency generator engine, with ISEGS 3 having two emergency generator engines (4 total at the site). Additionally, it is proposed that the facility have tractor pulled mirror washing trailers and dedicated pickup trucks for personnel transport within the plants, which will create both tailpipe and fugitive dust emissions during operation.

PROJECT CONSTRUCTION

Construction of each of the three phases of the facility would last about 24 months, with a 12 month overlap between each phase. Thus, the construction of the entire facility would last up to four years. The construction is scheduled in the order of the plant number, and the construction of the gas pipeline is scheduled to occur during months 7 and 8 of ISEGS 1 construction.

Air Quality Table 6 presents the applicant's estimate of direct onsite and offsite (delivery and employee vehicle) construction emissions for NOx, VOC, SOx, CO, PM10 and PM2.5.

Air Quality Table 6
ISEGS Construction Emissions

Solar Facility Construction	Daily Emissions (lbs/day) [a]					
	NOx	SOx	CO	VOC	PM10	PM2.5
Maximum Daily Onsite Emissions	363	1	117	23	199	46
Maximum Daily Offsite Emissions	137	1	392	40	86	16
Maximum Daily Emissions	500	2	509	63	285	63
	Annual Emissions (tons/year) [a]					
Maximum Annual Onsite Emissions	29.9	0.1	9.9	2.0	18.5	4.3
Maximum Annual Offsite Emissions	11.4	0.1	34.3	3.5	6.0	1.5
Maximum Annual Emissions	41.3	0.2	44.2	5.4	24.5	5.8

Source: AFC (BSE2007a), and Data Responses (CH2ML 2008h).
Notes:
a. Emissions include fugitive dust.

The emission estimate appears reasonable in terms of the onsite equipment and offsite vehicle use and the offsite vehicle fugitive dust emissions. However, the onsite fugitive dust emissions estimate may be underestimated given the amount of activity on the site and appropriate level of control for the applicant's proposed mitigation measures (specifically watering unpaved roads). Staff has recommended additional mitigation measures, specifically the use of soil binders on unpaved roads and other inactive disturbed surfaces during construction, so that the applicant's fugitive dust emissions estimate and associated impact analysis will be reasonable for this project.

The emission values in **Air Quality Table 6** include incorporation of the fugitive dust mitigation measures. The unmitigated PM10 annual emission potential during construction would potentially be greater than 100 tons per year, so without mitigation the annual PM10 emissions would have the potential to exceed General Conformity applicability thresholds and the project would require a formal conformity determination as per the federal Clean Air Act (CAA) General Conformity Rule.

PROJECT OPERATION

The ISEGS facility would be a nominal 400 Megawatt (MW) heliostat mirror and power tower thermal solar electrical generating facility comprised of three plants, ISEGS 1 (100 MW), ISEGS 2 (100 MW) and ISEGS 3 (200 MW) (BSE 2007a). The direct air pollutant emissions from solar power generation are minimal; however, the facility will start-up each day with the assist of one large boiler associated with each plant and there are other auxiliary equipment and maintenance activities necessary to operate and maintain the facility.

The ISEGS onsite stationary and mobile emission sources are as follows:

- Three natural gas fueled boilers, two 231.1 MMBtu/hr boilers (ISEGS 1 and ISEGS 2), and one 462.2 MMBtu/hr boiler (ISEGS 3) used for daily startup, each limited to no more than 4 hours of use per day and no more than 1,460 hours of use per year;
- Three 240-bhp diesel-fired emergency fire water pump engines, one for each plant, that will operate in non-emergency mode no more than 50 hours per year or no more than required by National Fire Protection Association, whichever is greater;
- Four 3,750-bhp diesel-fired emergency generator engines fire water pump engines, one each for ISEGS 1 and 2, and two for ISEGS 3 that will operate in non-emergency mode no more than 50 hours per year;
- Onsite diesel and gasoline fueled maintenance vehicles used for mirror washing and other maintenance/operation support activities.

The following assumptions were used to develop the hourly, daily, and annual emissions estimate for ISEGS operation:

A. Maximum Hourly Emissions

- All boilers are operating.
- One emergency generator engine operates one-half hour for testing purposes.
- The maximum hourly use of the maintenance vehicles is 1/2000th the annual use, which is 60 miles for the heavy-duty mirror washing vehicles and 15 miles for the pickup trucks.
- 25 employees are traveling 50 mile one-way trip to/from the site and one heavy-duty delivery vehicle is traveling 50 mile one-way to/from the site during the hour.

B. Maximum Daily Emissions

- All boilers operate for 4 hours per day.
- All four emergency generator engines operate one hour each for testing purposes.
- All three emergency fire pump engines operate one hour each for testing purposes.
- The maximum daily use of the maintenance vehicles is 1/250th the annual use, which is 480 miles for the heavy duty mirror washing vehicles and 120 miles for the pickup trucks.

- 66 employees traveling 100 mile round trips to/from the site during the day and three heavy-duty delivery vehicle travel 100 mile round trips to/from the site during the day.

C. Maximum Annual Emissions

- All boilers operate for 1,460 hours per year.
- All four emergency generator engines operate 50 hours per year for testing purposes.
- All three emergency fire pump engines operate 50 hours per year for testing purposes.
- The heavy duty mirror washing vehicles travel 120,000 miles per year and the on-site pickup trucks travel 30,000 miles per year.
- There is a total of 2.34 million employee vehicle miles traveled and a total of 12,000 heavy-duty delivery vehicle miles traveled annually.

The ISEGS onsite stationary source, onsite mobile equipment, and offsite vehicle emissions, including fugitive PM10 emissions, are estimated and summarized in **Air Quality Table 7**.

Air Quality Table 7
ISEGS Operation - Maximum Hourly, Maximum Daily, and Annual Emissions

	Maximum Hourly Emissions (lbs/hr)					
Emission Source	NOx	SOx	CO	VOC	PM10	PM2.5
Boilers	10.00	2.50	16.90	4.90	6.80	6.80
Emergency Generator Engines	19.43	0.02	10.75	0.41	0.62	0.57
Emergency Fire Pump Engines	0.00	0.00	0.00	0.00	0.00	0.00
Maintenance Vehicles (all types)	2.32	0.02	1.48	0.18	14.60	3.13
Employee and Delivery Vehicles (offsite)	3.62	0.03	19.15	1.88	1.40	0.37
Total Maximum Hourly Emissions	35.38	2.57	48.28	7.38	23.41	10.87
Emission Source	Maximum Daily Emissions (lbs/day)					
Boilers	40.0	10.0	67.6	19.6	27.2	27.2
Emergency Generator Engines	77.7	0.1	43.0	1.7	2.5	2.3
Emergency Fire Pump Engines	4.6	0.0	4.1	0.2	0.2	0.2
Maintenance Vehicles (all types)	18.6	0.2	11.9	1.4	116.8	25.0
Employee and Delivery Vehicles (offsite)	20.5	0.2	101.9	10.0	7.4	2.0
Total Maximum Daily Emissions	161.4	10.4	228.4	32.9	154.1	56.7
Emission Source	Annual Emissions (tons/year) [a]					
Boilers	7.3	1.8	12.3	3.6	5.0	5.0
Emergency Generator Engines	3.9	0.0	2.1	0.1	0.1	0.1
Emergency Fire Pump Engines	0.1	0.0	0.1	0.0	0.0	0.0
Maintenance Vehicles (all types)	2.3	0.0	1.5	0.2	14.6	3.1
Employee and Delivery Vehicles (offsite)	1.8	0.0	17.1	1.7	1.2	0.3
Total Annual Emissions	15.4	1.9	33.1	5.5	20.9	8.5

Source: BSE 2007a, CH2ML 2008a, Tier II and Tier III maximum emissions for the engines and staff estimates of paved road dust emissions for the employee and delivery vehicles.

Note:

a – The annual emissions are based on permit limits, but the actual annual boiler use and annual emissions are expected to be less than a third of the permit limits.

Similar to the construction emissions estimate staff believes that the onsite fugitive dust emissions estimate may be underestimated given the amount of activity on the site and appropriate level of control for the applicant's proposed mitigation measures (specifically watering unpaved roads). Staff has recommended additional mitigation measures, specifically the use of soil binders on unpaved roads and other inactive disturbed surfaces during site operation, so that the applicant's fugitive dust emissions estimate and associated impact analysis will be reasonable for this project.

The emission values in **Air Quality Table 7** include incorporation of the fugitive dust mitigation measures. The unmitigated PM10 annual emission potential during operation would potentially be greater than 100 tons per year, so without mitigation the annual PM10 emissions would have the potential to exceed General Conformity applicability thresholds and the project would require a formal conformity determination as per the CAA General Conformity Rule.

The direct stationary source emissions from this project are well below the PSD and/or nonattainment NSR permitting applicability thresholds; therefore, the facility is considered a minor stationary source and likely would not create significant NEPA impacts.

Project Construction and Operation Overlap

For a period of time, the construction and operation of the facilities will overlap due to the staged construction and operation of the three plants. The applicant estimated the maximum overlapping emissions when ISEGS 1 is operating and ISEGS 2 is in construction and when ISEGS 1 and 2 are operating and ISEGS 3 is in construction. **Air Quality Table 8** presents the determined worst-case overlapping construction and operation emissions, which occur when operating ISEGS 1 and 2 and constructing ISEGS 3.

Air Quality Table 8
ISEGS Maximum Construction and Operations Overlap Emissions

	Hourly Emissions (lbs/hour) [a]					
Solar Facility Construction	NOx	SOx	CO	VOC	PM10	PM2.5
Construction Onsite Emissions	36.3	0.1	11.7	2.3	19.9	4.6
Construction Offsite Emissions	13.7	0.1	39.2	4.0	8.6	1.6
Solar Facility Operation						
Operation Onsite Emissions	26.0	1.3	20.2	3.0	13.8	6.1
Operation Offsite Emissions	2.4	0.0	12.8	1.3	0.9	0.2
Maximum Hourly Overlap Emissions	78.4	1.5	83.9	10.6	43.2	12.5
Solar Facility Construction	Daily Emissions (lbs/day) [a]					
Construction Onsite Emissions	363.4	1.0	116.7	23.0	199.2	46.3
Construction Offsite Emissions	136.9	1.3	392.3	39.7	85.9	16.5
Solar Facility Operation						
Operation Onsite Emissions	74.3	5.2	66.0	11.7	92.9	31.6
Operation Offsite Emissions	13.7	0.1	67.9	6.7	4.9	1.3
Maximum Daily Overlap Emissions	588.3	7.6	642.9	81.1	382.9	95.7
Solar Facility Construction	Annual Emissions (tons/year) [a]					
Construction Onsite Emissions	29.9	0.1	9.9	2.0	18.5	4.3
Construction Offsite Emissions	11.4	0.1	34.3	3.5	6.0	1.5
Solar Facility Operation						
Operation Onsite Emissions	7.2	0.9	8.3	2.0	12.3	4.6
Operation Offsite Emissions	1.2	0.0	11.4	1.1	0.8	0.2
Maximum Annual Emissions	49.7	1.1	63.9	8.6	37.6	10.6

Source: Data Responses (CH2ML 2008h) and staff's assessment of offsite emissions.
Note:
a. Emissions include fugitive dust and construction emissions are based on a 10-hour construction day.

The applicant modeled the onsite emissions shown above for the operation of ISEGS 1 and 2 and the construction of ISEGS 3, as well as the worst-case onsite emissions associated with operation of ISEGS 1 and construction of ISEGS 2 to determine the estimated worst-case impacts during project construction and partial operation overlap.

INITIAL COMMISSIONING

Initial commissioning refers to a period of approximately 60 days prior to beginning commercial operation when the equipment undergoes initial tuning and performance tests. Staff does not expect substantial change of emissions from the facility commissioning to that of full production.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assessed three kinds of primary and secondary[2] impacts: construction, operational, and cumulative. Construction impacts result from the emissions occurring during site preparation and construction of the project. Operational impacts result from the emissions of the proposed project during normal operation, which includes all of the onsite auxiliary equipment (boilers, cooling tower, fire pump engine, etc.) and the maintenance vehicle emissions. Cumulative impacts result from the proposed project's

[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.

incremental effect, together with other closely related past, present and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project. (Pub. Resources Code § 21083; Cal. Code Regs., tit. 14, §§ 15064(h), 15065(c), 15130, and15355.)

METHOD AND THRESHOLD FOR DETERMINING CEQA SIGNIFICANCE

Energy Commission staff used two main CEQA significance criteria in evaluating this project. First, all project emissions of nonattainment criteria pollutants and their precursors (NOx, VOC, PM10 and SO_2) are considered CEQA significant cumulative impacts that must be mitigated. Second, any AAQS violation or any contribution to any AAQS violation caused by any project emissions is considered CEQA significant and must be mitigated. Potentially significant CEQA impacts are mitigated to less than significant with the application of maximum feasible mitigation.

For construction emissions, the mitigation that is considered is limited to controlling both construction equipment tailpipe emissions and fugitive dust emissions to the maximum extent feasible.

For operating emissions, when analyzing renewable projects with very low direct criteria pollutant emissions from stationary sources associated with electric generation that: 1) are located in areas with generally good air quality; and 2) are non-attainment of ambient air quality standards primarily or solely due to pollutant transport, the mitigation that is considered is limited to feasible emission controls. These feasible emission controls are applied to both the stationary sources (such as BACT) and the on-site non-stationary emission sources (such as maintenance vehicles) including associated fugitive dust emission sources.

The ambient air quality standards that staff uses as a basis for determining project CEQA significance are health-based standards established by the ARB and U.S. EPA. They are set at levels 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, including a margin of safety.

NEPA AIR QUALITY ANALYSIS METHODOLOGY

The NEPA air quality analysis considers the following three regulatory thresholds:

- General Conformity applicability thresholds, which for this project is limited to 100 tons per year of PM10 and PM10 precursors (NOx and SOx). This regulatory threshold applies to both project construction and operation emissions.
- PSD permit applicability thresholds, which for this project as a listed major source category is 100 tons per year for the criteria pollutants. This regulatory threshold only applies to project operation and only applies to direct project emissions, and does not apply to secondary emissions, such as fugitive dust emissions.
- Project would cause air quality impacts in exceedance of the NAAQS.

If the project were to exceed any of first two of these regulatory thresholds then the impacts would be considered potentially significant and would require a further refined

impact and mitigation analysis in order to demonstrate that the Project would not result in a significant impact based on the potential to cause exceedances of the NAAQS. However, regardless of the NEPA requirements for this project, a refined impact and mitigation analysis has been conducted per CEQA requirements, and that analysis and the resulting NEPA findings are described in detail in this document.

Impacts from Closure and Decommissioning

Impacts from closure and decommissioning, as a one-time limited duration event, are evaluated with the same methods and thresholds as construction emissions as discussed above.

DIRECT/CUMULATIVE IMPACTS AND MITIGATION

While the emissions are the actual mass of pollutants emitted from the project, the impacts are the concentration of pollutants from the project that reach the ground level. When emissions are expelled at a high temperature and velocity through the relatively tall stack, the pollutants would be substantially diluted by the time they reach ground level. The emissions from the proposed 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 magnitude 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 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 applicant has used the U.S. EPA-approved ARMS/EPA Regulatory Model (AERMOD version 07026) air dispersion model to estimate the direct impacts of the project's NOx, PM10, CO, and SOx emissions resulting from project construction and operation. Additionally, boiler emission fumigation impacts during inversion breakup conditions were determined using the U.S. EPA approved SCREEN3 model.

Staff revised the background concentrations provided by the applicants, replacing them with the available highest ambient background concentrations for the last three year from representative monitoring sites as show in **Air Quality Table 5**. Staff added the modeled impacts to these background concentrations, then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or would contribute to an existing violation.

The inputs for the air dispersion models include stack information (exhaust flow rate, temperature, and stack dimensions), specific boiler emission data and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the Jean, Nevada, meteorological site during 2001 and 2002, which is the closest complete meteorological data source to the project site, and

supplemented to fill missing data using the Nellis Air Force Base meteorological site. Concurrent upper air data from the Mercury Desert Rock Airport in Mercury, Nevada was also used.

Additionally, the applicant obtained hourly ozone and NO_2 ambient data from the Barstow monitoring station for 2001 and 2002 that was used in a more refined NO_2 impact modeling analysis using the Plume Volume Molar Ratio Method (PVMRM), available with AERMOD that integrates the Ozone Limiting Method (OLM) with the downwind plume stoichiometry.

Proposed Project

Construction Impacts Analysis

The ISEGS project consists of three phases, each of which would require approximately 24 months of partially overlapping construction that would last a total of 48 months (BSE2007a). Construction generally consists of two major activities: site preparation, and construction and installation of major equipment and structures. In addition to fugitive dust emissions resulting from the site preparation, emissions from construction equipment exhausts, such as vehicles and internal combustion engines, would also occur during the project construction phase. In addition, a small amount of hydrocarbon emissions may occur because of the temporary storage of petroleum fuel at the site.

Using estimated peak hourly, daily, and annual construction equipment exhaust and fugitive dust emissions, the applicant performed a modeling analysis. **Air Quality Table 9** presents the results of the applicant's modeling analysis.

Air Quality Table 9
Maximum Project Construction Impacts

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background [a] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr	200.4	73.3	273.7	339	81%
	Annual	0.2	7.3	7.5	57	13%
PM10	24-hr	6.7	96	102.7	50	205%
	Annual	0.2	12.7	12.9	20	65%
PM2.5	24-hr	1.6	12.9	14.5	35	41%
	Annual	0.0	4.5	4.5	12	38%
CO	1-hr	109	4,025	4,134	23,000	18%
	8-hr	24	1,367	1,391	10,000	14%
SO_2	1-hr	0.9	94.3	95.2	665	14%
	24-hr	0.0	13.1	13.1	105	12%
	Annual	0.0	2.7	2.7	80	3%

Source: CH2ML 2008h.
Note:
a - Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.

This modeling analysis indicates, with the exception of 24-hour PM10 impacts, that the project would not create new exceedances or contribute to existing exceedances for any of the modeled air pollutants. Staff notes that the maximum local background 24-hour measurements of PM10 may be substantially impacted by wind-blown dust. However, in light of the existing PM10 and ozone non-attainment status for the project

site area, staff considers the construction NOx, VOC, and PM emissions to be potentially CEQA significant and, therefore, staff is recommending that the off-road equipment and fugitive dust emissions be mitigated to the extent feasible.

The modeling analysis shows that, after implementation of the recommended fugitive dust mitigation measures, the project's construction is not predicted to cause violations of the NAAQS. Therefore, no significant NEPA impacts would occur after implementation of the fugitive dust mitigation measures.

Construction Impacts Mitigation

To mitigate the impacts due to construction of the facility, the applicant has proposed to use the following mitigation measures from the South Coast Air Quality Management District CEQA Guidelines (CH2ML 2008i):

A. All unpaved roads and disturbed areas in the project and linear construction sites will be watered until sufficiently wet to ensure that no visible dust plumes leave the project site.

B. Vehicle speeds will be limited to 10 miles per hour within the construction site.

C. All construction equipment vehicle tires will be washed or cleaned free of dirt prior to entering paved roadways.

D. Gravel ramps will be provided at the tire washing/cleaning station.

E. All entrances to the construction site will be graveled or treated with water or dust soil stabilization compounds.

F. Construction areas adjacent to any paved roadway will be provided with sandbags to prevent run-off to the roadway.

G. All paved roads within the construction site will be swept twice daily when construction activity occurs.

H. At least the first 500 feet of any paved public roadway, accessed from the construction site or from unpaved roads en route to the construction site and construction staging areas will be swept regularly on days when construction activity occurs.

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

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

K. Wind erosion control techniques such as windbreaks, water, chemical dust suppressants, and vegetation will be used on all construction areas that may be

disturbed. Any windbreaks used will remain in place until the soil is stabilized or permanently covered with vegetation.

L. Construction equipment will be shut down to avoid excessive idling emissions.

M. Construction equipment will use low sulfur, low aromatic diesel fuel.

N. Construction equipment will be maintained in top service shape.

O. Construction equipment used will meet state and federal emission standards for Tier II and Tier III.

Staff recommends the implementation of mitigation measures contained in Conditions of Certification **AQ-SC1 to AQ-SC5**, which incorporate the applicant's proposed measures with revisions and additions recommended by staff to reduce the impacts from the construction of the proposed project. Specific recommendations from staff include a more aggressive dust control requirement to use polymer based, or equivalent, soil stabilizers[3] on the site's unpaved roads and inactive disturbed surfaces during construction.

The construction of the project would cause particulate matter emissions that would add to the existing violations of the ambient PM10 air quality standards. Therefore, if unmitigated, the project's construction PM10 emission impacts would be CEQA significant. Additionally, unmitigated PM10 emissions could exceed General Conformity applicability thresholds, and could potentially cause NEPA significant impacts. However, staff believes that the implementation of proposed specific mitigation measures during construction of the facility as identified in the conditions of certification would eliminate the potential to cause the short-term CEQA impacts of PM10 to a level of less than significant, and would mitigate the potential for NEPA significant impacts.

Operational Impacts

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

[3] The soil stabilizer product used will require prior approval by BLM and the Energy Commission.

Operational Modeling Analysis

The applicant has provided a modeling analysis using the EPA-approved AERMOD model to estimate the impacts of the project's NOx, PM10, CO, and SOx emissions[4] resulting from project operation (CH2ML 2008h). Similar to the assessment of construction impacts, staff added the modeled impacts to the available highest ambient background concentrations recorded during the previous three years from nearby monitoring stations to assess the project operational impacts. **Air Quality Table 10** presents the results of the applicant's modeling analysis.

Air Quality Table 10
Project Operation Emissions Impacts

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background [a] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr	150.4	73.3	223.4	339	66%
	Annual	0.1	7.3	7.4	57	13%
PM10	24-hr	3.3	96	99.3	50	199%
	Annual	0.5	12.7	13.2	20	66%
PM2.5 [c]	24-hr [b]	0.2	12.9	13.1	35	37%
	Annual	0.0	4.5	4.5	12	38%
CO	1-hr	321	4,025	4,346	23,000	19%
	8-hr	55	1,367	1,422	10,000	14%
SO_2	1-hr	3.9	94.3	98.2	665	15%
	24-hr [b]	0.1	13.1	13.2	105	13%
	Annual	0.0	2.7	2.7	80	3%

Source: CH2ML 2008h.
Notes:
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.
[b] Maximum 24-hour hour PM2.5 and SO_2 concentrations occur under fumigation conditions.
[c] PM2.5 impacts were not remodeled to include maintenance emissions like the other pollutants, the results presented are stationary source emission only from the original AFC modeling analysis. With the maintenance PM2.5 emission the PM2.5 results would be higher than shown but lower than the PM10 results as the PM2.5 emissions are less than the PM10 emissions. Therefore, the PM2.5 impacts with maintenance emissions would not create new exceedances of the ambient air quality standards.

This modeling analysis indicates, with the exception of 24-hour PM10 impacts, that the project would not create new exceedances or contribute to existing exceedances for any of the modeled air pollutants. Staff notes that the maximum local background 24-hour measurements of PM10 may be substantially impacted by wind-blown dust. However, in light of the existing PM10 and ozone non-attainment status for the project site area, staff considers the operating NOx, VOC, and PM emissions to be potentially

[4] The applicant's modeling analysis uses assumptions that are somewhat different than those presented in the emissions table (**Air Quality Table 7**). Specifically, for the annual emissions modeling the applicant assumed 520 hours of boiler operation rather than the permitted maximum 1,460 hours, and for all averaging periods used manufacturer specified engine emission factors rather than the worst-case emission standard based values used by staff in **Air Quality Table 7;** and assumed one-hour of emergency engine testing rather than the permitted maximum one-half hour of testing. These differences would not change staff's overall modeling analysis impact findings, but staff will be adding a condition of certification limiting boiler operation, in terms of heat input, to that which was modeled. This heat input level restriction also formalizes the applicant's stipulation that "Heat input from natural gas will not exceed 5 percent of the heat input from the sun, on an annual basis". (BSE 2007a, p. 5.1-1).

CEQA significant and, therefore, staff is recommending that the stationary equipment, the off-road maintenance equipment, and fugitive dust emissions be mitigated to the extent feasible.

The modeling analysis shows that, after implementation of the recommended fugitive dust mitigation measures, the project's operation is not predicted to cause violations of the NAAQS. Therefore, no significant NEPA impacts would occur after implementation of the fugitive dust mitigation measures.

Construction/Operation Overlapping Impacts

The applicant has provided a modeling analysis using the EPA-approved AERMOD model to estimate the impacts of the project's NOx, PM10, CO, and SOx emissions[5] resulting from worst-case overlap when the project is in partial operation and still being constructed (CH2ML 2008h). Similar to the assessment of the construction and operating impacts, staff added the modeled impacts to the available highest ambient background concentrations recorded during the previous three years from nearby monitoring stations to assess the project overlapping construction/operation impacts. **Air Quality Table 11** presents the results of the applicant's modeling analysis.

Air Quality Table 11
Project Overlapping Construction/Operation Emission Impacts

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background [a] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr	202.4	73.3	275.7	339	81%
	Annual	0.3	7.3	7.6	57	13%
PM10	24-hr	10.4	96	106.4	50	213%
	Annual	0.3	12.7	13.0	20	65%
PM2.5	24-hr	3.2	12.9	16.1	35	46%
	Annual	0.3	4.5	4.8	12	40%
CO	1-hr	261	4,025	4,286	23,000	19%
	8-hr	52	1,367	1,419	10,000	14%
SO_2	1-hr	3.6	94.3	97.9	665	15%
	24-hr	0.0	13.1	13.1	105	12%
	Annual	0.0	2.7	2.7	80	3%

Source: CH2ML 2008h.
Notes:
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.

This modeling analysis again indicates, with the exception of 24-hour PM10 impacts, that the project would not create new exceedances or contribute to existing exceedances for any of the modeled air pollutants. Considering the existing PM10 and ozone non-attainment status for the project site area, staff considers the construction and operating NOx, VOC, and PM emissions to be potentially CEQA significant and, therefore, as noted previously staff is recommending that the construction and operations emission sources be mitigated to the extent feasible.

[5] The applicant's modeling analysis uses assumptions that are somewhat different than those presented in the emissions table (**Air Quality Table 8**). Specifically, for the operating emissions used are revised as previously noted for the operating emission impact modeling.

The modeling analysis shows that, after implementation of the recommended fugitive dust mitigation measures, the project's worst-case construction/operation overlap period is not predicted to cause violations of the NAAQS. Therefore, no significant NEPA impacts would occur after implementation of the fugitive dust mitigation measures.

Chemically Reactive Pollutant Impacts

The project will have direct emissions of chemically reactive pollutants (NOx, SOx, and VOC), but will also have indirect emission reductions associated with the reduction of fossil-fuel fired power plant emissions due to the project displacing the need for their operation. The exact nature and location of such reductions is not known and the overall magnitude and downwind impact of those upwind emission reductions is speculative and staff's impact analysis has not considered these potential reductions as an offset source for the project's emissions, so the discussion below focuses on the direct emissions from the project.

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 modeling 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 ISEGS project do have the potential (if left unmitigated) to contribute to higher ozone levels in the region, which are already designated nonattainment for the state ozone standard.

PM2.5 Impacts

Secondary particulate formation, which is assumed to be 100% 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 the acids 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 will 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. There are two conditions that are of interest, described as *ammonia rich* and *ammonia poor*. The term ammonia rich indicates that there is more than enough ammonia to react with all the sulfuric acid and to establish a balance of nitric acid-ammonium nitrate. Further ammonia emissions in this case would not necessarily lead to increases in ambient PM2.5 concentrations. In the case of an ammonia poor environment, there is insufficient ammonia to establish a balance and thus additional ammonia would tend to increase PM2.5 concentrations.

The northeastern San Bernardino County portion of the Mojave Desert Air Basin has not undergone the rigorous secondary particulate studies that have been performed in other areas of California, such as the San Joaquin Valley, that have more serious fine

particulate pollution problems. However, due to the limited agricultural activity in the area the project site area would likely be characterized as ammonia poor, and the ISEGS project is not a notable source of ammonia emissions so the small amount of operating NOx and SOx emissions that would be generated by this project would have a reduced potential to create secondary particulate.

Impact Summary

The applicant is proposing to mitigate the project's stationary source NOx, VOC, SO_2, and PM10/PM2.5 emissions through the use of boiler emission controls (Low NOx burner and flue gas recirculation) and natural gas fuel for the boilers, and use emergency engines that meet the highest available EPA/ARB Tier emission standards fueled with California 15 ppm sulfur diesel fuel. Additionally, staff recommends additional mitigation, specified in conditions of certification **AQ-SC6** and **AQ-SC7,** to reduce maintenance vehicle emissions, both tailpipe emission and fugitive dust emissions that could contribute to further ozone and PM10 violations. With the applicant proposed and staff recommended emission mitigation, it is staff's belief that the project would not cause CEQA significant secondary pollutant impacts.

Operations Mitigation

Applicant's Proposed Mitigation

Emission Controls

As discussed in the air quality section of the AFC (BSE 2007a), the applicant proposes the following emission controls on the stationary equipment associated with the ISEGS operation:

Boilers

The applicant's proposed mitigation for the three boilers includes Low-NOx burners and 20 percent flue gas recirculation (for NOx), good combustion practices (for CO), and operate exclusively on pipeline quality natural gas (for VOC, PM and SOx) to limit boiler emission levels. The AFC (BSE 2007a), and FDOC conditions (MDAQMD 2009b) provides the following emission limits, each for the two smaller (231.1 MMBtu/hour) boilers:

- NOx: 9.0 ppmvd at 3% O_2 (one-hour average), 2.5 lb/hour
- CO: 25 ppmvd at 3% O_2 (one-hour average), 4.2 lb/hour
- VOC: 12.6 ppmvd, 1.2 lb/hour
- PM10: 1.7 lb/hour
- SO_2: 1.7 ppmvd, 0.6 lb/hour

And provide the following emission limit for the larger (462.2 MMBtu/hour) boiler:

- NOx: 9.0 ppmvd at 3% O_2 (one-hour average), 5.0 lb/hour
- CO: 25 ppmvd at 3% O_2 (one-hour average), 8.5 lb/hour
- VOC: 12.6 ppmvd, 2.5 lb/hour

- PM10: 3.47 lb/hour
- SO_2: 1.7 ppmvd, 1.3 lb/hour

Emergency Generator Engines

The applicant's proposed controls for the emergency generator engine is to purchase a new engine meeting current emission standard requirements (Tier 2) for 3,470 bhp engines. Additionally only ARB low sulfur (15 ppm) diesel fuel will be used. The specific emission levels for the selected engine are currently unknown but they will be no higher than following Tier 2 emission standards:

- NOx: 4.8 grams per break horsepower (including non-methane hydrocarbons - NMHC)
- CO: 2.6 grams per break horsepower
- VOC: (see NOx above)
- PM10: 0.15 grams per break horsepower
- SO_2: 15 ppm sulfur content fuel

Fire Water Pump Engines

The applicant's proposed the use of a Tier 2 Engine. However, based on currently regulatory requirements (NSPS Subpart IIII - Table 4) staff will be requiring the use of a Tier 3 engine for the 240 horsepower fire pump engines that will have emission not higher than the following Tier 3 emission standards:

- NOx: 3.0 grams per break horsepower (including NMHC)
- CO: 2.6 grams per break horsepower
- VOC: (see NOx above)
- PM10: 0.15 grams per break horsepower
- SO_2: 15 ppm sulfur content fuel

Maintenance Vehicles

The applicant has not proposed any specific emission controls for this emission source.

Delivery and Employee Vehicles

The applicant has not proposed any specific emission controls for this emission source.

Emission Offsets

The applicant has not proposed any emission offsets and the stationary source emissions for ISEGS as currently proposed by the applicant would be well below District offset thresholds.

Adequacy of Proposed Mitigation

Staff concurs with the District's determination that the project's stationary source proposed emission controls/emission levels for criteria pollutants meets regulatory requirements and that the proposed stationary source emission levels are reduced adequately.

Staff Proposed Mitigation

As mentioned earlier in the discussions of the ozone and PM10 impacts, staff believes that the project's ozone precursors and PM10 emissions, if unmitigated, could cause CEQA significant. Additionally, staff believes a solar renewable project, which would have a 30 to 40-year life, located in an ozone and PM10 nonattainment area and just upwind of other ozone and PM10 nonattainment areas, should address its contribution to the potentially ongoing nonattainment of the PM10 and ozone standards. Therefore, staff recommends the following additional mitigation measures:

- Require the use new model year vehicles at the time of purchase for onsite maintenance, or equivalently low emitting vehicles as long as those vehicles can be demonstrated to have a similar or lower emission profile than new model year vehicles.
- Limit vehicle speeds within the facility to no more than ten miles per hour on unpaved areas that have not undergone soil stabilization, and up to 25 miles per hour on stabilized unpaved roads as long as no visible dust plumes are observed, to address fugitive PM emissions from the site;
- Apply and maintain a non-toxic soil binder[6] to the onsite unpaved roads to create a durable stabilized surface;
- Additional ongoing operations fugitive dust emissions control techniques such as windbreaks, trackout controls, etc. should be identified in a fugitive dust control plan and used on areas that could be disturbed by vehicles or wind. Any windbreaks used would remain in place until the soil or road is stabilized: and

Staff recommendations for onsite maintenance vehicles and ongoing fugitive dust emissions control are in conditions of certification **AQ-SC6** and **AQ-SC7**, respectively.

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

Staff recommendation to require the engines meet model year EPA/ARB Tier emission standards for the year purchased is in condition of certification **AQ-SC9**.

Staff recommends Condition of Certification **AQ-SC10** to ensure that the boiler operation does not exceed the amount that was modeled in the applicant's air quality modeling analysis and to formalize the applicant's stipulation that "Heat input from natural gas will not exceed 5 percent of the heat input from the sun, on an annual basis". (BSE 2007a, p. 5.1-1).

[6] The soil stabilizer product used will require prior approval by BLM and the Energy Commission.

Staff believes that the implementation of its recommended mitigation measures would reduce the potential CEQA emission impacts from the facility on ozone and PM10 to a level of less than significant. Additionally, staff believes that the implementation of its recommended operations fugitive dust mitigation measure would mitigate the potential for NEPA adverse impacts.

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

Closure and Decommissioning Impacts and Mitigation

Eventually the facility will 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 to operate and thus impacts associated with those emissions would no longer occur. The only other expected emissions would be equipment exhaust and fugitive particulate emissions from the dismantling activities. These activities would be of much a shorter duration than construction of the project, equipment are assumed to have much lower comparative emissions due to technology advancement, and fugitive dust emissions would be required to be controlled in a manner at least equivalent to that required during construction. Therefore, while there will be adverse CEQA air quality impacts during decommissioning they are expected to be less than significant.

Alternative 1 – No Action Alternative

In the No Project / No Action Alternative, the proposed action would not be undertaken. The Bureau of Land Management (BLM) land on which the project is proposed would continue to be managed within BLM's framework of a program of multiple use and sustained yield, and the maintenance of environmental quality [43 U.S.C. 1781 (b)] in conformance with applicable statutes, regulations, policy and land use plan.

The results of the No Project / No Action Alternative would be the following:

- The impacts of the proposed project would not occur. However, the land on which the project is proposed would become available to other uses that are consistent with BLM's land use plan, including another solar project.
- The benefits of the proposed project in displacing fossil fuel fired generation and reducing associated pollutant emissions would not occur.

If this project were not approved, renewable projects would likely be developed on other sites in the Mojave Desert or in adjacent states as developers strive to provide renewable power that complies with utility requirements and State/Federal mandates. For example, there are two large solar projects proposed on BLM land in California and Nevada within a few miles of the Ivanpah site. In addition, as of August 2009 there were 66 applications for solar projects covering 611,692 acres pending with BLM in the California Desert District (CDD).

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 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 analysis is concerned with *criteria* air pollutants. Such pollutants have impacts that are usually (though not always) cumulative by nature. Rarely would a project 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 the existing background sources 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 air 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.

Much of the preceding discussion is concerned with cumulative impacts. The "Existing Ambient Air Quality" subsection describes the air quality background in northeastern San Bernardino County portion of the Mojave Desert Air Basin, including a discussion of historical ambient levels for each of the assessed criteria pollutants. The "Construction Impacts and Mitigation" subsection discusses the project's contribution to the local existing background caused by project construction. The "Operation Impacts and Mitigation" subsection discusses the 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;
- an analysis of the project's *localized cumulative impacts*, the project's direct operating emissions combined with other local major emission sources;

Summary of Projections

The northeastern San Bernardino County portion of the MDAB is designated as non-attainment for both the federal and State PM10 standards, and for the State ozone standard. PM2.5, CO, NO_2, and SO_2 are all considered to be attainment or unclassified for the federal and State standards.

Ozone

Since a portion of San Bernardino County in the Mojave Desert is currently classified as non-attainment, south and west of the project site, for the federal 8-hour ozone standard, the District is required to prepare and adopt an ozone attainment plan for

submittal to the U.S. EPA describing how it will achieve attainment with the federal 8-hour standard. The project is not specifically subject to the provisions in the federal attainment plan and the site is outside of the non-attainment area.

Particulate Matter

The District is currently classified as nonattainment for the state and the federal 24-hour PM10 air quality standard. The District first adopted a Federal Particulate Matter (PM10) Attainment Plan (PMAP) in July 31, 1995. However, some experts are critical of the federal standards as not being sufficiently health protective. California has adopted standards that are far more stringent for PM10. Currently, virtually all air districts in the state (the lone exception being Lake County) are designated nonattainment of the state PM10 standard. There is no legal requirement for air districts to provide plans to attain the state PM10 standard, so air districts have not developed such plans.

In 1997, the federal government adopted PM2.5 standards, as did the state in 2003. The EPA has determined that the area is unclassified, or attainment for both the annual and the 24-hour federal PM2.5 standard. However, the ARB classified the area as nonattainment of the annual state PM2.5 air quality standard.

The PMAP states that "(t)he air quality of the MDAQMD is impacted by both fugitive dust from local sources and occasionally by region-wide wind blown dust during moderate to high wind episodes. This region-wide or “regional” event includes contributions from both local and distant dust sources which frequently result in violations of the NAAQS that are multi-district and interstate in scope." It also states that "(i)t is not feasible to implement control measures to reduce dust from regional wind events." Therefore, the District would have put considerable effort to reduce the emissions from "…unpaved road travel, construction, and local disturbed areas in the populated areas, and certain stationary sources operating in the rural Lucerne Valley*."*

As a solar power generation facility, the direct air pollutant emissions from power generation are negligible and the emission sources are limited to auxiliary equipment and maintenance activities. With the mitigation required by the recommended staff conditions and District conditions, it is unlikely that the project would have a CEQA significant impact on particulate matter emissions.

Summary of Conformance with Applicable Air Quality Plans

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

Localized Cumulative Impacts

Since ISEGS air quality impacts can be reasonably estimated through air dispersion modeling (see the “Operational Modeling Analysis” subsection) the project 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

“Environmental Setting” 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 applicant) 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 six miles of the project site. Based on staff’s modeling experience, beyond six miles there is no statistically considerable concentration overlap for non-reactive pollutant concentrations between two stationary emission sources.
- Second, the Energy Commission staff (or the applicant) works with the air district and local counties to identify any new area sources within six 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 project, thus a local major source might not be well represented by the background air monitoring. 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 two 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 the ISEGS if the high impact area is the result of high fence line concentrations from another stationary source and BSEP 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 applicant 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 Data Adequacy phase of the licensing procedure. Staff typically assists the applicant 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 applicant to complete. There are several reasons for this: modeling analyses take time to perform and require substantial expertise, the applicant has already performed a modeling analysis of the project alone (see the "Operational Modeling Analysis" subsection), and the applicant 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 project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or the applicant (see the "Mitigation" subsection).

The applicant, in consultation with the District, has conducted a survey of stationary sources that are either under construction, or have received permits to be built or operate in the near future and that have the potential for emissions of criteria air contaminants within six miles of the project site. The survey results indicate that no such sources exist within the 6-miles radius[7] of the proposed project site (CH2ML 2008a).

There are several proposed projects near the project site including several other renewable energy facilities (solar and wind), an airport, a high speed train, a new commercial/residential development in Jean, and other long-term projects with minimal air quality impacts, and temporary projects with no long term air quality impacts. In general, most of these projects would create minimal long-term emissions, but construction emissions of the other renewable energy facilities, the airport, and the large development in Jean will likely have high temporary emissions from construction vehicles and fugitive dust. In the long-term, several of the developments should cause beneficial impacts such as the high-speed train reducing traffic emissions on I-15, and the renewable energy projects reducing emissions within the area of the Western Electricity Coordinating Council (WECC).

No additional cumulative air quality impact modeling analysis was performed, and while adverse cumulative impacts would likely occur, no CEQA significant cumulative air quality impacts are expected after implementation of staff's recommended project mitigation measures. However, staff is aware of a tremendous potential development of wind and solar in the desert southwest of the United States, and in the California Desert Conservation Area where ISEGS would be located. While the number of renewable project filings is much larger than what will eventually be built and operated in the desert southwest, staff believes it is appropriate to construct and operate the desert renewable projects with best practices to reduce any potential cumulative effects, including criteria pollutants and their contributions to region ozone and particulate matter and haze. Staff recommends Conditions of Certification **AQ-SC1** and **AQ-SC-7** as best practices for the construction and operation of the ISEGS desert solar project, which may be one of many in the area and greater southwest region.

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

[7] Staff assumes that impacts from projects beyond six miles would not affect the modeling analysis on a cumulative basis.

COMPLIANCE WITH LORS

The Mojave Desert Air Quality Management District issued the Preliminary Determination of Compliance (PDOC) for the ISEGS on December 23, 2008 (MDAQMD 2009), and the Final Determination of Compliance (FDOC), second revision version Rev. B, on July 15, 2009 (MDAQMD 2009b). Compliance with all District rules and regulations was demonstrated to the District's satisfaction in the DOC. The District's FDOC conditions are presented in the Conditions of Certification.

FEDERAL

The District is responsible for issuing the federal New Source Review (NSR) permit, the federal Title V permit, and has been delegated enforcement of the applicable New Source Performance Standard (Subparts, Da, Db, and IIII). The applicant will be required to submit a Title V permit application to the District within 12 months of commencing operation. Additionally, this project would not require a PSD permit from U.S. EPA.

The project is located in a federal nonattainment area and requires the approval of a federal agency (BLM). Therefore, the project is subject to the general conformity regulations (40 CFR Part 93). The project area is moderate nonattainment of the federal PM10 ambient air quality standards, and the general conformity emissions applicability thresholds for this nonattainment classification is 100 tons/year of direct and indirect PM10 emissions and 100 tons/year of direct and indirect PM10 precursor (NOx and SOx) emissions. The project's maximum annual unmitigated direct and indirect emissions of PM10 during construction and operation would have the potential to exceed the 100 tons threshold, while the unmitigated NOx and SOx emissions from construction and operation would not have the potential to exceed the 100 tons/year threshold. However, the mitigated direct and indirect construction and operation emissions, as shown in **Air Quality Tables 6** through **8** have been determined to be well below the applicable General Conformity applicability thresholds of 100 tons per year for PM10, SOx, and NOx. Therefore, the project is not required to complete a conformity analysis and conformance with the State Implementation Plan is assumed.

STATE

The applicant would demonstrate that the project would comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury, with the issuance of the District's Final Determination of Compliance and the Energy Commission's affirmative finding for the project. In the FDOC, the District concluded that the project should comply with this requirement as the screening health risk assessment they performed found risks to be below a Prioritization Score of 1.0, or below the need for any additional analysis or action.

The fire pump and emergency generator engines are also subject to the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines. This measure limits the types of fuels allowed, established maximum emission rates, establishes recordkeeping requirements. The proposed Tier II engine meets the emission limit requirements of this rule. This measure would also limit the engine's testing and maintenance operation to 50 hours per year.

LOCAL

The District rules and regulations specify the emissions control and offset requirements for new sources such as the ISEGS. Best Available Control Technology would be implemented, and emission reduction credits (ERCs) are not required to offset the project's emissions by District rules and regulations based on the permitted stationary source emission levels for this project. Compliance with the District's new source requirements would ensure that the 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 MDAQMD in September 2007; and the District issued the PDOC on February 14, 2008 (MDAQMD 2008a), issued the FDOC on December 3, 2008 (MDAQMD 2008b), and issued two applicant requested revisions to the FDOC, Rev. A on April 9, 2009 (MDAQMD 2009a) and Rev. B on July 15, 2009 (MDAQMD 2009b). The FDOC 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 II – Permits

Rule 201 and 203 – Permit to Construct and Permit to Operate

Rule 201 establishes the emission source requirements that must be met to obtain a Permit to Construct. Rule 203 prohibits use of any equipment or the use of which may emits air contaminants without obtaining Permit to Operate. The applicant has submitted all required applications, therefore, the applicant is in compliance with these rules.

Rule 221 – Federal Operating Permit Requirement

Rule 221 requires certain facilities to obtain Federal Operating Permits. Title V permitting will be required as a result of Acid Rain rule applicability for the proposed project. The applicant will be required to submit an application for a Title V permit to comply with this rule.

Regulation IV – Prohibitions

Rule 401 - Visible Emissions

This rule limits visible emissions from emissions sources, including stationary source exhausts and fugitive dust emission sources. Compliance with this rule is expected.

Rule 402 - Nuisance

This rule restricts discharge of emissions that would cause injury, detriment, annoyance, or public nuisance. 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 staff condition **AQ-SC3** and **AQ-SC7,** the facility is expected to comply with this rule.

Rule 404 - Particulate Matter Concentration

Rule 404 limits particulate matter (PM) emissions to less than 0.1 grains per standard cubic foot of gas at standard conditions. In the FDOC, the District has determined that the estimated PM emission concentrations of the proposed boilers and engines are less than 0.006 gr/dscf and 0.05 gr/dscf, respectively. These proposed emission rates are well below the limits established by this rule, therefore compliance is expected.

Rule 405 – Solid Particulate Matter Weight

Rule 405 prohibits discharge of solid particulate matter, such as lead and lead compounds, into the atmosphere. The ISEGS is expected to operate in compliance with this rule.

Rule 406 – Specific Contaminants

Rule 406 prohibits discharge of sulfur compounds, calculated as SO_2, in excess of 0.05 percent by volume (500 ppmv), and acid gas emissions above specified levels. SO_2 emissions from the propose project would be below 0.5 ppmv, based on the fuel sulfur content limit of 0.75 gr/100 scf. Compliance is expected.

Rule 407 – Liquid and Gaseous Air Contaminants

Rule 407 prohibits discharge of carbon monoxide (CO) in excess of 2,000 ppmv. The CO emissions from the boilers, firewater pumps, and emergency generator engines would be well below 2,000 ppmv in compliance with this rule.

Rule 431 – Sulfur Content of Fuels

Rule 431 prohibits the burning of gaseous fuel with sulfur content in excess of 800 ppm and liquid fuel with a sulfur content of more than 0.5 percent sulfur by weight. With the requirement of utility grade natural gas for the boilers and the requirement of ARB ultra-low sulfur diesel fuel, ISEGS would operate in compliance with this rule.

Rule 463 – Storage of Organic Liquids

This rule is to limit the emissions of volatile organic compounds (VOC) and toxic compounds during the storage of organic liquid. 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 is proposing a diesel storage tank but no gasoline storage tank or other organic liquid with a true vapor pressure of 1.5 pounds per square inch or greater; therefore, the requirements of this rule do not apply.

Rule 475 – Electric Power Generating Equipment

Rule 475 limits emissions of NOx and PM from electric generating equipment, and this rule is applicable to the emergency engine of the proposed project. This rule limits NOx and PM emission no more than 160 ppmv, and 0.01 gr/dscf at 3 percent O_2. Compliance is expected with the proposed Tier II emergency diesel engines.

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 District evaluated compliance with Subpart Da that applies to the ISEGS 3 boiler and Subpart Db that applies to the ISEGS 1 and 2 boilers and has provided conditions they believe ensure compliance with these regulations. However, staff believes that two specific exhaust monitoring requirements required by Subparts Da and Db, NO_2 monitoring for the ISEGS 1 and 2 boilers and oxygen monitoring for the ISEGS 3 boiler, may need to be clarified, or revised conditions added to the boiler permits, prior to construction of the boilers. Staff has added verification language that will require the project owner make a clear determination regarding these monitoring requirements.

The proposed Tier II engines meet the emission limit requirements of the NSPS ((Subpart IIII) that applies to the proposed ISEGS emergency generators engines; however, the NSPS (Table 4) requires that the fire pump engines meet regulatory stationary IC equivalent engine emission requirements (Tier III) by 2009 model years. Therefore, staff has added a condition insuring that engines meet the latest ARB/U.S. EPA emission standards when they are purchased.

Regulation XIII – New Source Review

Rule 1303 – New Source Review

This rule requires implementation of BACT for any emission source unit that emits or has the potential to emit 25 lbs/day or more, and emission offsets if total facility emissions exceed annual thresholds. The District permits limit the emissions from each source to less than 25 lbs/day, so BACT is not applicable; and the permits limit the total site annual emission below offset thresholds, so offsets are not applicable.

Rule 1306 – Electric Energy Generating Facilities

Describes actions to be taken for permitting of power plants. The District has issued a PDOC and an FDOC in compliance with the requirements of this rule.

NOTEWORTHY PUBLIC BENEFITS

Renewable energy facilities, such as the ISGES, are needed to meet California's mandated renewable energy goals.

PUBLIC AND AGENCY COMMENTS ON THE PSA

No public or agency comments were received on the Preliminary Staff Assessment (PSA) Air Quality analysis. However, the applicant and an intervenor, Basin Range and Watch (BRW), did provide comments. The applicant's comments have been addressed as appropriate within this Final Staff Assessment (FSA). The BRW comment is summarized and addressed below.

BRW Comment 2
For dust control during operation and construction, where will water come from? How much will be used? This should be explained and estimated numbers of gallons should be listed.

Staff Response
The source of water for dust control during plant construction and operation is assumed to be the same on-site ground water wells used for other plant water needs (see Soil and Water Resources section). The applicant estimated 128 acre-feet of use during the 15 months of initial grading for the three project phases (BSE 2007a, p. 5.15-14), which is also presented in the Soil and Water Resources section (**Soil & Water Table 3**) based on a 5 day per week construction schedule and 5 months of initial grading per construction phase. However, the applicant did not provide estimates of water use for dust control during the rest of the construction period or for ongoing operations. Staff has modified the recommended conditions of certification (**AQ-SC3** and **AQ-SC7**) to both increase dust control efficiency and minimize water use through the required use of polymeric dust suppressants on the site's unpaved roads and other disturbed surfaces to create and maintain stabilized surfaces during project construction and operation.

CONCLUSIONS

Staff has made the following conclusions about the ISEGS:

- The project would not have the potential to exceed PSD emission levels during direct source operation and the facility is not considered a major stationary source with potential to cause significant NEPA air quality impacts. However, without adequate fugitive dust mitigation, the project would have the potential to exceed the General Conformity PM10 applicability threshold during construction and operation, and could cause potential localized exceedances of the PM10 NAAQS during construction and operation. Recommended Conditions of Certification **AQ-SC1** through **AQ-SC4**, for construction, and **AQ-SC7**, for operation, will mitigate these potentially significant NEPA impacts.
- The project would comply with applicable District Rules and Regulations, including New Source Review requirements, and staff recommends the inclusion of the Districts FDOC conditions as Conditions of Certification **AQ-1** through **AQ-39** and the addition of staff recommended Condition of Certification **AQ-SC9** to ensure that the emergency engines meet applicable model year emission standards.
- The project's construction activities would likely contribution to significant CEQA adverse PM10 and ozone impacts. Staff recommends **AQ-SC1** to **AQ-SC5** to mitigate the potential impacts.
- The project's operation would not cause new violations of any NO_2, SO_2, PM2.5 or CO ambient air quality standards, and therefore, the project direct operational NOx, SOx, PM2.5 and CO emission impacts are not CEQA significant.
- The 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 **AQ-SC6** to mitigate the onsite maintenance vehicle emissions and **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.

- Staff recommends **AQ-SC10** to formalize the applicant's stipulation that "Heat input from natural gas will not exceed 5 percent of the heat input from the sun, on an annual basis", which also generally corresponds the amount of operation included in the applicant's air dispersion modeling impact analysis.
- The project would be consistent with the requirements of SB 1368 and the Emission Performance Standard for greenhouse gases (see **Appendix Air-1**).

MITIGATION MEASURES/ PROPOSED CONDITIONS OF CERTIFICATION

STAFF CONDITIONS OF CERTIFICATION

Staff conditions **AQ-SC1** through **AQ-SC4** and **AQ-SC7** are both CEQA and NEPA mitigation conditions. Staff conditions **AQ-SC5**, **AQ-SC6**, and **AQ-SC8** through **AQ-SC10** are CEQA-only conditions.

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 60 days prior to the start of ground disturbance, the project owner shall submit to the BLM's Authorized Officer and 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 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the BLM's Authorized Officer and CPM for approval. The AQCMP shall include effectiveness and environmental data for the proposed soil stabilizer. The BLM's Authorized Officer or CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the BLM's Authorized Officer and CPM in each Monthly Compliance Report that demonstrates compliance with the following mitigation measures for the purposes of preventing all fugitive dust plumes from leaving the project. Any deviation from the following mitigation measures shall require prior BLM Authorized Officer and CPM notification and approval.

A. The main access roads through the facility to the power block areas will be paved prior to initiating construction in the main power block area, and delivery areas for operations materials (chemicals, replacement parts, etc.) will be paved prior to taking initial deliveries.

B. All unpaved construction roads and unpaved operational 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. All other disturbed areas in the project and linear construction sites shall be watered as frequently as necessary during grading and stabilized with a non-toxic soil stabilizer or soil weighting agent 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 and BLM Authorized Officer..

I. Construction areas adjacent to any paved roadway 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 at least twice daily (or 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 at least twice daily (or 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 BLM's Authorized Officer and the CPM a Monthly Compliance Report (**COMPLIANCE-6**) 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 BLM Authorized Officer, CPM, and 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 or BLM Authorized Officer 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 or BLM Authorized Officer before that time.

Verification: The AQCMM shall provide the BLM's Authorized Officer and the CPM a Monthly Compliance Report (**COMPLIANCE-6**) 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 and 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 MCR, a construction mitigation report that demonstrates compliance with the following mitigation measures for purposes of controlling diesel construction-related emissions. Any deviation from the following mitigation measures shall require prior and CPM notification and approval.

a. All 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.

b. All construction diesel engines with a rating of 50 hp or higher shall meet, at a minimum, the Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines, as specified in California Code of Regulations, Title 13, section 2423(b)(1), unless a good faith effort that is certified by the on-site AQCMM demonstrates that such engine is not available for a particular item of equipment. This good faith effort shall be documented with signed written correspondence by the appropriate construction contractors along with documented correspondence with at least two construction equipment rental firms. In the event that a Tier 3 engine is not available for any off-road equipment larger than 100 hp, that

equipment shall be equipped with a Tier 2 engine, or an engine that is equipped with retrofit controls to reduce exhaust emissions of 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 “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. The construction equipment is intended to be on site for 5 days or less.

3. The CPM may grant relief from this requirement if the AQCMM can demonstrate a good faith effort to comply with this requirement and that compliance is not possible.

c. The use of a retrofit control device may be terminated immediately, provided that the CPM is informed within 10 working days of the termination and that a replacement for the equipment item in question meeting the controls required in item “b” occurs within 10 days of termination of the use, if the equipment would be needed to continue working at this site for more than 15 days after the use of the retrofit control device is terminated, if one of the following conditions 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 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.

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.

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.

f. Construction equipment will employ electric motors when feasible.

Verification: The AQCMM shall include in the Monthly Compliance Report (**COMPLIANCE-6**):

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

B. A list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that 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.

AQ-SC6 The project owner, when obtaining dedicated vehicles for mirror washing activities and other facility maintenance activities, shall only obtain new model year vehicles that meet California on-road vehicle emission standards for the model year when obtained.

Other vehicle/fuel types may be allowed assuming that the emission profile for those vehicles, including fugitive dust generation emissions, is comparable to the vehicles types identified in this condition.

Verification: At least 60 days prior to the start commercial production, 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 and submitted in the Annual Compliance Report (**COMPLIANCE-7**).

AQ-SC7 The project owner shall provide a site operations dust control plan, including all applicable fugitive dust control measures identified in **AQ-SC3** that would be applicable to reducing fugitive dust from ongoing operations; 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 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 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.

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

Verification: At least 60 days prior to start of commercial operation, the project owner shall submit to the BLM's Authorized Officer and the CPM for review and approval a copy of the 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. At least 60 days after commercial operation, the project owner shall provide to the BLM's Authorized Officer and 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) 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 air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or U.S. Environmental Protection Agency (U.S. EPA), and any revised permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any ATC, PTO, and proposed air permit modification 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 air permits to the CPM within 15 days of receipt.

AQ-SC9 The emergency generator and fire pump engines procured for this project will meet or exceed the NSPS Subpart IIII emission standards for the model year that corresponds to their date of purchase.

Verification: The project owner shall submit the emergency engine specifications to the CPM at least 30 days prior to purchasing the engines for review and approval.

AQ-SC10 The ISEGS 1, ISEGS 2, and ISEGS 3 boilers shall not exceed a total annual natural gas fuel heat input that is more than 5 percent of the total annual heat input from the sun for ISEGS1, ISEGS2, and ISEGS 3, respectively.

Verification: Annual natural gas fuel heat input data and annual solar heat input data for the ISEGS 1, ISEGS 2, and ISEGS 3 units showing compliance with this condition shall be provided in the Annual Compliance Report (**COMPLIANCE-7**).

DISTRICT CONDITIONS OF CERTIFICATION

District conditions **AQ-1** through **AQ-39** are CEQA-only required conditions.

Conditions Applicable to Ivanpah 1 & 2 Boilers, MDAQMD Application Numbers/Permit Numbers; 00009311 (B010375) & 00009314 (B010376)

Equipment Description:

Nebraska boilers, Model NSX-G-120, each equipped with Natcom Low-NOx Burners rated at a maximum heat input of 231.1 MMBTU/hr, and flue gas recirculation (FGR or EGR) operating at 13.9 percent excess air, fueled exclusively on utility grade natural gas. Equipment boiler is equipped with stacks that are 130 feet high and 60 inches in diameter.

These conditions apply separately to both boilers unless otherwise specified.

AQ-1 Operation of this equipment must be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: Any non-compliant operations shall be listed in the Annual Compliance Report (**COMPLIANCE-7**).

AQ-2 The owner/operator shall operate this equipment in strict accord with the recommendations of the manufacturer or supplier and/or sound engineering principles and consistent with all information submitted with the application for this permit, which produce the minimum emission of air contaminants.

Verification: As part of the Annual Compliance Report (**COMPLIANCE-7**), the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-3 This boiler shall use only natural gas as fuel and shall be equipped with a meter measuring fuel consumption in standard cubic feet.

Verification: As part of the Annual Compliance Report (**COMPLIANCE-7**), the project owner shall include proofs that only pipeline quality, or Public Utility Commission regulated natural gas are used for the boilers.

AQ-4 The owner owner/operator shall maintain a current, on-site (at a central location if necessary) log for this equipment for five (5) years, which shall be provided to District, state or federal personnel upon request. This log shall include calendar year fuel use for this equipment in standard cubic feet, or BTU's, and daily hours of operation.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or Energy Commission staff.

AQ-5 Not later than 180 days after initial startup, the operator shall perform an initial compliance test on this boiler in accordance with the District Compliance Test Procedural Manual. This test shall demonstrate that this equipment does not exceed the following emission maximums:

Pollutant	ppmvd	Lb/MMBtu	Lb/hr	
*NOx	9.0	0.011	2.5	(per USEPA Methods 19 and 20)
SOx	1.7	0.003	0.6	
*CO	25.0	0.018	4.2	(per USEPA Methods 10)
VOC	12.6	0.0054	1.2	(per USEPA Methods 25A and 18)
PM10	n/a	0.007	1.7	(per USEPA Methods 5 and 202 or CARB Method 5)

*corrected to 3% oxygen, on a dry basis, averaged over one hour

Verification: The project owner shall notify the District and the CPM within fifteen (15) working days before the execution of the compliance test required in this condition. The test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-6 This boiler shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart Db - Standards of Performance for Industrial Steam Generating Units (NSPS Db).

Verification: The project owner shall complete and submit to the CPM a compliance plan that provides a list of the 40 CFR 60 Subpart Db plans, tests, and recordkeeping requirements and their compliance schedule dates as applicable for the ISEGS Boilers 1 and 2 at least 30 days prior to first fire of the boilers or earlier as necessary for compliance with Subpart Db.

AQ-7 Records of fuel supplier certifications of fuel sulfur content shall be maintained to demonstrate compliance with the sulfur dioxide and particulate matter emission limits.

Verification: Complying with Condition of Certification **AQ-3** shall be used to demonstrate compliance with this condition.

AQ-8 The owner/operator shall continuously monitor fuel flow rate and flue gas oxygen level.

Verification: At least 120 days prior to construction of the boiler stacks, the project owner shall provide the District for approval, and the CPM for review, a detailed drawing and a plan on how the measurements and recordings, required by this condition, will be performed by the chosen monitoring system.

AQ-9 The owner/operator shall conduct an initial compliance test for NOx emissions within 180 days of startup. This initial compliance test shall be used to develop a relationship between fuel firing rate, flue gas oxygen, and flue gas NOx concentration. This relationship shall be used to determine compliance with NOx emission limits contained in these conditions.

Verification: The project owner shall notify the District and the CPM within fifteen (15) working days before the execution of the compliance test required in this condition. The test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-10 The owner/operator shall comply with all applicable recordkeeping and reporting requirements of NSPS Db.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-11 This boiler shall not operate more than 4 hours in any single day, and no more than 1460 hours in any calendar year.

a. These limits shall not apply during the facility commissioning period. The commissioning period shall begin the first time fuel is fired in the boiler. The commissioning period shall end when the facility achieves commercial operation, but no later than 180 days after first fire.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

Conditions Applicable to Ivanpah 3 Boiler, MDAQMD Application Number; 00009320

Equipment Description:

Babcock-Wilcox boiler, Model unknown, equipped with an unknown Low-NOx Burner rated at a maximum heat input of 462.2 MMBTU/hr, and flue gas recirculation (FGR or EGR) operating at 13.9 percent excess air, fueled exclusively on utility grade natural gas. Equipment shall use 450,000 cu-ft/hr of fuel and provide 440,000 lb/hr of steam. This boiler is equipped with a stack that is 130 feet high and 60 inches in diameter.

AQ-12 Operation of this equipment must be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: Any non-compliant operations shall be listed in the Annual Compliance Report (**COMPLIANCE-7**).

AQ-13 The owner/operator shall operate this equipment in strict accord with the recommendations of the manufacturer or supplier and/or sound engineering principles and consistent with all information submitted with the application for this permit, which produce the minimum emission of air contaminants.

Verification: As part of the Annual Compliance Report, (**COMPLIANCE-7**) the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-14 This boiler shall use only natural gas as fuel and shall be equipped with a meter measuring fuel consumption in standard cubic feet.

Verification: As part of the Annual Compliance Report (**COMPLIANCE-7**), the project owner shall include proofs that only pipeline quality, or Public Utility Commission regulated natural gas are used for the boilers.

AQ-15 The owner owner/operator shall maintain a current, on-site (at a central location if necessary) log for this equipment for five (5) years, which shall be provided to District, state or federal personnel upon request. This log shall include calendar year fuel use for this equipment in standard cubic feet, or BTU's, and daily hours of operation.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or Energy Commission staff.

AQ-16 Not later than 180 days after initial startup, the operator shall perform an initial compliance test on this boiler in accordance with the District Compliance Test Procedural Manual. This test shall demonstrate that this equipment does not exceed the following emission maximums:

Pollutant	ppmvd	Lb/MMBTU	Lb/hr	
*NOx	9.0	0.011	5	(per USEPA Methods 19 and 20)
SOx	1.7	0.003	1.3	
*CO	25.0	0.018	8.5	(per USEPA Methods 10)
VOC	12.6	0.0054	2.5	(per USEPA Methods 25A and 18)
PM10	n/a	0.007	3.4	(per USEPA Methods 5 and 202 or CARB Method 5)

*corrected to 3% oxygen, on a dry basis, averaged over one hour

Verification: The project owner shall notify the District and the CPM within fifteen (15) working days before the execution of the compliance test required in this condition. The test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-17 This boiler shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart Da - Standards of Performance for Industrial Steam Generating Units (NSPS Da).

Verification: The project owner shall complete and submit to the CPM a compliance plan that provides a list of the 40 CFR 60 Subpart Da plans, tests, and recordkeeping requirements and their compliance schedule dates as applicable for the ISEGS Boiler 3 at least 30 days prior to first fire of the boiler or earlier as necessary for compliance with Subpart Da.

AQ-18 Records of fuel supplier certifications of fuel sulfur content shall be maintained to demonstrate compliance with the sulfur dioxide and particulate matter emission limits.

Verification: Complying with Condition of Certification **AQ-14** shall be used to demonstrate compliance with this condition.

AQ-19 The owner/operator shall install, calibrate, maintain and operate a continuous emissions monitoring system (CEMS) to measure and record NOx emissions and oxygen concentration according to 40 CFR Part 60 specifications.

Verification: At least 120 days prior to construction of the boiler stacks, the project owner shall provide the District for approval and the CPM for review, a detailed drawing

and a plan on how the measurements and recordings, required by this condition, will be performed by the chosen monitoring system.

AQ-20 The owner/operator shall conduct an initial compliance test for NOx emissions by conducting the CEMS RATA test within 180 days of startup; and shall collect data from the CEMS at all times that fuel is combusted in the boiler.

Verification: The project owner shall notify the District and the CPM within fifteen (15) working days before the execution of the compliance test required in this condition. The test results shall be submitted to the District and to the CPM within 60 days of the date of the tests.

AQ-21 The owner/operator shall comply with all applicable recordkeeping and reporting requirements of NSPS Da.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-22 This boiler shall not operate more than 4 hours in any single day, and no more than 1460 hours in any calendar year.

a. These limits shall not apply during the facility commissioning period. The commissioning period shall begin the first time fuel is fired in the boiler. The commissioning period shall end when the facility achieves commercial operation, but no later than 180 days after first fire.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

Conditions Applicable to Ivanpah I, II, and III Emergency Fire Pumps, MDAQMD Application Numbers/Permit Numbers; 00009312 (E010380), 00009315 (E010378), and 00009319 (E010384)

Equipment Description:

Year of Manufacture 2008, Tier II, One Clarke, Diesel fired internal combustion engine, Model No. JU6H-UF62, and Serial number tbd, After Cooled, Direct Injected, Turbo Charged, producing 240 bhp with 6 cylinders at 2,600 rpm while consuming a maximum of 10 gal/hr. This equipment powers a pump.

These conditions apply separately to all three emergency fire pump engines unless otherwise specified.

AQ-23 This system shall be installed, operated and maintained in strict accord with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of contaminants. Unless otherwise noted, this equipment shall also be operated in accordance with all data and specifications submitted with the application for this permit.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, EPA or CEC staff.

AQ-24 These engines may operate in response to notification of impending rotating outage if the area utility has ordered rotating outages in the area where the engines are located or expects to order such outages at a particular time, the engines are located in the area subject to the rotating outage, the engines are operated no more than 30 minutes prior to the forecasted outage, and the engines are shut down immediately after the utility advises that the outage is no longer imminent or in effect.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-25 These engines may operate in response to fire suppression requirements and needs.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-26 These units shall only be fired on ultra-low sulfur diesel fuel, whose sulfur concentration is less than or equal to 0.0015% (15ppm) on a weight per weight basis per CARB Diesel or equivalent requirements.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-27 A non-resettable four-digit (9,999) hour timer shall be installed and maintained on these units to indicate elapsed engine operating time.

Verification: At least thirty (30) days prior to the installation of the engine, the project owner shall provide the District and the CPM the specification of the hour timer.

AQ-28 These units shall be limited to use for emergency power, defined as in response to a fire or when commercially available power has been interrupted. In addition, this unit shall be operated no more than 50 hours per year for testing and maintenance, excluding compliance source testing. Time required for source testing will not be counted toward the 50 hour per year limit.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-29 The hour limit of **AQ-28** can be exceeded when the emergency fire pump assemblies are driven directly by a stationary diesel fueled CI engine when operated per and in accord with the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 2006 edition or the most current edition approved by the CARB Executive Officer. {Title 17 CCR 93115(c)16}

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-30 The owner/operator shall maintain a operations log for these units current and on-site, either at the engine location or at a on-site location, for a minimum of two (2) years, and for another year where it can be made available to the

District staff within 5 working days from the District's request, and this log shall be provided to District, State and Federal personnel upon request. The log shall include, at a minimum, the information specified below:

a. Date of each use and duration of each use (in hours);

b. Reason for use (testing & maintenance, emergency, required emission testing);

c. Calendar year operation in terms of fuel consumption (in gallons) and total hours; and,

d. Fuel sulfur concentration (the owner/operator may use the supplier's certification of sulfur content if it is maintained as part of this log).

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-31 These fire protection units are subject to the requirements of the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines (Title 17 CCR 93115). In the event of conflict between these conditions and the ATCM, the more stringent requirements shall govern.

Verification: Not necessary.

Conditions Applicable to Ivanpah I, II, and III Emergency Generators, MDAQMD Application Numbers/Permit Numbers; 00009313 (E010381), 00009316 (E010379), 00009317 (E010382) and 00009318 (E010383)

Equipment Description:

Year of Manufacture 2008, Tier II, One Caterpillar, Diesel fired internal combustion engine, Model No. 3516C-HD, and Serial No. tbd, After Cooled, Direct Injected, Turbo Charged, producing 3,750 bhp with 16 cylinders at 1,800 rpm while consuming a maximum of 173 gal/hr. This equipment powers a Generator.

These conditions apply separately to all four emergency generator engines unless otherwise specified.

AQ-32 Engine may operate in response to notification of impending rotating outage if the area utility has ordered rotating outages in the area where the engine is located or expects to order such outages at a particular time, the engine is located in the area subject to the rotating outage, the engine is operated no more than 30 minutes prior to the forecasted outage, and the engine is shut down immediately after the utility advises that the outage is no longer imminent or in effect.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-33 This unit shall only be fired on ultra-low sulfur diesel fuel, whose sulfur concentration is less than or equal to 0.0015% (15ppm) on a weight per weight basis per CARB Diesel or equivalent requirements.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-34 This equipment shall be installed, operated and maintained in strict accord with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of contaminants. Unless otherwise noted, this equipment shall also be operated in accordance with all data and specifications submitted with the application for this permit.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-35 A non-resettable four-digit (9,999) hour timer shall be installed and maintained on this unit to indicate elapsed engine operating time.

Verification: At least thirty (30) days prior to the installation of the engine, the project owner shall provide the District and the CPM the specification of the hour timer.

AQ-36 This unit shall be limited to use for emergency power, defined as in response to a fire or when commercially available power has been interrupted. In addition, this unit shall be operated no more than 50 hours per year, and no more than 0.5 hours per day for testing and maintenance, excluding compliance source testing. Time required for source testing will not be counted toward the 50 hour per year limit.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-37 The owner/operator shall maintain an operations log for this unit current and on-site (or at a central location) for a minimum of five (5) years, and this log shall be provided to District, State and Federal personnel upon request. The log shall include, at a minimum, the information specified below:

a. Date of each use and duration of each use (in hours);

b. Reason for use (testing & maintenance, emergency, required emission testing);

c. Calendar year operation in terms of fuel consumption (in gallons) and total hours; and,

d. Fuel sulfur concentration (the owner/operator may use the supplier's certification of sulfur content if it is maintained as part of this log).

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

AQ-38 This genset is subject to the requirements of the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines (Title 17 CCR 93115). In the event of conflict between these conditions and the ATCM, the more stringent requirements shall govern.

Verification: Not necessary.

AQ-39 This unit shall not be used to provide power during a voluntary agreed to power outage and/or power reduction initiated under an Interruptible Service Contract (ISC); Demand Response Program (DRP); Load Reduction Program (LRP) and/or similar arrangement(s) with the electrical power supplier.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CEC staff.

ACRONYMS

AAQS	Ambient Air Quality Standard
ACC	Air Cooled Condenser
AERMOD	ARMS/EPA Regulatory Model
AFC	Application for Certification
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMD	Air Quality Management District
ARB	California Air Resources Board
ATC	Authority to Construct
ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
bhp	brake horsepower
BLM	Bureau of Land Management
BRW	Basin Range and Watch
Btu	British thermal unit
CAA	Clean Air Act (Federal)
CAAQS	California Ambient Air Quality Standard
CCR	California Code of Regulations
CDD	California Desert District
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
dscf	dry standard cubic feet
EIR	Environmental Impact Report
ERC	Emission Reduction Credit
FDOC	Final Determination Of Compliance
FSA	Final Staff Assessment
GHG	Greenhouse Gas
gr	Grains (1 gr $\cong$ 0.0648 grams, 7000 gr = 1 pound)
hp	horsepower
H_2S	Hydrogen Sulfide
HSC	Health and Safety Code
ISEGS	Ivanpah Solar Electric Generating System (proposed project)

lbs	Pounds
LORS	Laws, Ordinances, Regulations and Standards
MCR	Monthly Compliance Report
MDAB	Mojave Desert Air Basin
MDAQMD	Mojave Desert Air Quality Management District
mg/m^3	milligrams per cubic meter
MMBtu	Million British thermal units
MW	Megawatts (1,000,000 Watts)
NAAQS	National Ambient Air Quality Standard
NH_3	Ammonia
NMHC	Non-Methane Hydrocarbons
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates
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)
PSD	Prevention of Significant Deterioration
PTO	Permit to Operate
PVMRM	Plume Volume Molar Ratio Method
scf	Standard Cubic Feet
SO_2	Sulfur Dioxide
SO_3	Sulfate
SOx	Oxides of Sulfur

U.S. EPA	United States Environmental Protection Agency
$\mu g/m^3$	Microgram per cubic meter
VOC	Volatile Organic Compounds

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APPENDIX AIR-1 - GREENHOUSE GAS EMISSIONS

Testimony of William Walters, P.E. and Matthew Layton, P.E.

SUMMARY OF CONCLUSIONS

The Ivanpah Solar Electric Generating System (ISEGS) project is a proposed addition to the state's electricity system. ISEGS is a solar concentrating thermal power plant, which is comprised of fields of heliostat mirrors focusing solar energy on boilers located on centralized power towers. As a solar project it would emit considerably less greenhouse gases (GHG) 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.

ISEGS, as a solar energy generation project, is exempt from the mandatory GHG emission reporting requirements for electricity generating facilities as currently required by the California Air Resources Board (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). However, the project may be subject to future reporting requirements and GHG reductions or trading requirements as these regulations become more fully developed and implemented.

On October 8, 2008, the Energy Commission adopted an order initiating an informational (OII) proceeding (08-GHG OII-1) to solicit comments on how to assess the greenhouse gas impacts of proposed new power plants in accordance with the California Environmental Quality Act (CEQA). This analysis provides the staff's conclusions concerning greenhouse gas emissions for this siting case. Future power plant siting and amendment cases are likely to be reviewed with the benefit of new information and policy direction from the Energy Commission in response to the OII. (CEC 2009a).

While ISEGS would emit some GHG emissions, ISEGS's contribution to the system build-out of renewable resources in California would result in a net cumulative reduction of energy and GHG emission from new and existing fossil resources. Electricity is produced by operation of inter-connected generation resources. Operation of one power plant, like ISEGS, affects all other power plants in the interconnected system. The operation of the ISEGS would affect the overall electricity system operation and GHG emissions in several ways:

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

These system impacts would result in a net reduction in GHG emissions across the electricity system providing energy and capacity to California. Thus, staff believes that

the 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 CEQA significant.

Staff concludes that the short-term minor emission of greenhouse gases during construction that are necessary to create this new low GHG-emitting power generating facility would be sufficiently reduced by “best practices” and would, therefore, not be CEQA significant.

The Ivanpah Solar Electric Generating System project, as a solar project with a nightly shutdown would operate less than 60% of capacity and is therefore not subject to the requirements of SB 1368 (Chapter 11, Greenhouse Gases Emission Performance Standard, Article 1, Section 2900 et. seq.). However, the ISEGS would easily comply with the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard.

INTRODUCTION

Greenhouse gas (GHG) emissions are not criteria pollutants, but they are discussed in the context of cumulative impacts. The state has demonstrated a clear willingness to address global climate change through research, adaptation[8] and inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

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

GLOBAL CLIMATE CHANGE AND ELECTRICITY PRODUCTION

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 greenhouse gases, 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).

[8] 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).

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

Applicable Law	Description
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 that will reduce GHG emission to 1990 levels. Electricity production facilities will be regulated by the ARB.
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	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).

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 greenhouse gases (GHG) or global climate change[9] 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 California Air Resources Board (ARB) to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020.[10] To achieve this, ARB has a mandate to define the 1990 emissions level and achieve the maximum technologically feasible and cost-effective GHG emission reductions.

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 major sources of GHG via regulations, market mechanisms, and other actions. ARB staff is developing regulatory language to implement its plan and holds ongoing public workshops on key elements of the recommended GHG reduction measures, including market mechanisms (ARB 2006). The regulations must be effective by January 1, 2011 and mandatory compliance commences on January 1, 2012. The mandatory reporting requirements are effective for electric generating facilities with a nameplate capacity equal or greater than 1 megawatt (MW) capacity, and the due date for initial reports by existing facilities this first year was June 1, 2009.

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

[10] Governor Schwarzenegger has also issued Executive Order S-3-05 establishing a goal of 80% below 1990 levels by 2050.

Examples of strategies that the state might pursue for managing GHG emissions in California, in addition to those recommended by the Energy Commission and the Public Utilities Commission, were identified in the California Climate Action Team's Report to the Governor (CalEPA 2006). The scoping plan approved by ARB in December 2008 builds upon the overall climate policies of the Climate Action Team report and show the 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), 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 Renewables Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade system that includes the electricity sector (ARB 2008b).

It is possible 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 effect for the least cost). For example, the ARB proposes a 40 percent reduction in GHG from the electricity sector, even though that sector currently only produces about 25 percent of the state GHG emissions. In response, in September 2008 the Energy Commission and the Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches, and identified regulation points should ARB decide that a multi-sector cap and trade system is warranted.

The Energy Commission's *2007 Integrated Energy Policy Report* (IEPR) also addresses climate change within the electricity, natural gas, and transportation sectors (CEC 2007). For the electricity sector, it recommends such approaches as pursuing all cost-effective energy efficiency measures and meeting the Governor's stated goal of a 33 percent renewable portfolio standard.

SB 1368[11], enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Emission Performance Standard of 0.500 metric tonnes CO_2 per megawatt-hour[12] (1,100 pounds CO_2/MWh). Specifically, the SB 1368 Emission Performance Standard applies (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.[13] If a project, instate or out of state, plans to sell base load electricity to California utilities, the utilities will have to demonstrate that the project meets the EPS. *Base load* units are defined as units that operate at a capacity factor higher than 60 percent. As a project with a permit operating restriction of less than 60 percent of the year, electricity from ISEGs would not have to meet the SB 1368 EPS.

[11] Public Utilities Code § 8340 et seq.

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

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

In addition to these programs, California is involved in the Western Climate Initiative, a multi-state and international effort to establish a cap and trade market to reduce greenhouse gas emissions in the Western United States and the Western Electricity Coordinating Council (WECC). The timelines for the implementation of this program 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.

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 meet demand, such that the dispatch of a new source of generation generally 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[14] 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.

California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system mix. The generation of electricity using fossil fuels, even in a back-up generator at a thermal solar plant, produces air emissions known as greenhouse gases in addition to the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. Greenhouse gas emissions contribute to the warming of the earth's atmosphere, leading to climate change.

For fossil fuel-fired power plants and equipment, these include primarily carbon dioxide, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 – often from unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment, and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very large relative global warming potentials. Global warming potential is a relative measure, compared to carbon dioxide, of a compound's residence time in the atmosphere and ability to warm the planet. Mass emissions of GHG are converted into carbon dioxide equivalent metric tonnes (MTCO2E) for ease of comparison.

[14] See page CEC 2009b, page 95.

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 greenhouse gases. Construction of the proposed project has three phase, each of which would last about 24 months. There would be a 12 month-overlapping period between each phase, which would result in 4 years of entire construction period. The applicant provided a construction emission estimate that staff used to calculate greenhouse gas emissions for the entirety of the construction activities. The greenhouse gas emissions estimate, presented below in **Greenhouse Gas Table 2,** were converted by staff into MTCO2E and totaled.

Greenhouse Gas Table 2
ISEGS Estimated Potential Construction Greenhouse Gas Emissions

Construction Element	CO_2-equivalent (MTCO2E) [a,b]
Off-road Equipment	10,444
Heavy Delivery Trucks	1,925
Construction Worker Transportation	5,410
Construction Total	17,779

Source: Staff estimates using the applicant's criteria pollutant emissions estimates (BSE 2007a)
[a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] The vast majority of the CO2E emissions, over 99 percent, are CO_2 from these combustion sources.

PROJECT OPERATIONS

Operations GHG emissions are shown in **Greenhouse Gas Table 3**. The proposed ISEGS project would cause GHG emissions from the power block maintenance activities, including mirror cleaning and minimal undesired vegetation removal, the weekly testing of the emergency generator and firewater pump, one hour per day of operation of each boiler, and employee trips.

Greenhouse Gas Table 3 shows what the proposed project, as permitted, could potentially emit in greenhouse gases on an annual basis. All emissions are converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled. For this solar project the primary fuel, solar energy, is greenhouse gas free, but there is a natural gas-fired steam boiler for each of the three plants. Other comparatively large GHG emission sources for this project are the testing of the emergency generator engines, maintenance vehicles, and worker vehicles. Testing of the firewater pump engines, delivery trips and SF_6 equipment leakage provide additional minor sources of GHG emissions.

Greenhouse Gas Table 3
Estimated ISEGS Potential Operating Greenhouse Gas Emissions

	CO_2-equivalent (MTCO2E[a] per year)
Boilers	25,458
Emergency Generator Engines	346
Fire Pump Engine	15
Maintenance Vehicles	474
Worker Vehicles	1118
Delivery and Waste Haul Vehicles	22
Equipment Leakage (SF_6)	10
Total Project GHG Emissions – MTCO2E [b]	**27,444**
Facility MWh per year [c]	960,000
Facility GHG Performance (MTCO2E/MWh)	0.029

Sources: BSE 2007a, where staff updated the natural gas GHG emissions factors to use the latest ARB recommendations (ARB 2008a) and included all operating GHG emission sources in the estimate.
[a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] The vast majority of the CO2E emissions, over 99 percent, are CO_2 from these emission sources.
[c] Approximately a 28 percent capacity factor. BSE2007a.

The proposed project would be permitted, on an annual basis, to emit over 27,000 metric tonnes of CO_2-equivalent per year if operated at its maximum permitted level. ISEGS is a solar project with a nightly shutdown so it will operate less than 60% of capacity; therefore, the project is not subject to the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard. However, the ISEGS, at 0.029 MTCO2E/MWh, would easily meet the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard of 0.500 MTCO2/MWh.

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 as discussed above.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses three kinds of impacts: construction, operation, and cumulative effects. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation. Cumulative impacts analysis assesses the impacts that result from the proposed 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 OII (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 ISEGS.

PROPOSED PROJECT

Construction Impacts

Staff does not believe that the small GHG emission increases from construction activities would be CEQA significant for several reasons. First, the period of construction will be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, best practices control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meet the latest emissions standards would further minimize greenhouse gas emissions since staff believes that the use of newer equipment will 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.

Direct/Indirect Operation Impacts and Mitigation

The proposed ISEGS promotes the state's efforts to move towards a high-renewable, low-GHG electricity system, and, therefore, reduce the amount of natural gas used by electricity generation and greenhouse gas emissions. As the *2007 Integrated Energy Policy* Report (CEC 2007, p. 184) noted:

> New natural gas-fueled electricity generation technologies offer efficiency, environmental, and other benefits to California, specifically by reducing the amount of natural gas used—and with less natural gas burned, fewer greenhouse gas emissions. Older combustion and steam turbines use outdated technology that makes them less fuel- and cost-efficient than newer, cleaner plants.… The 2003 and 2005 IEPRs noted that the state could help reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas power plants and replace or repower them with new, more efficient power plants.

Thus, in the context of the Energy Commission's *Integrated Energy Policy Report*, the ISEGS - solar-powered, limited GHG emissions and likely replacement of older existing plant capacity, furthers the state's strategy to promote generation system efficiency and reduce fossil fuel use and GHG emissions. As stated in the 2009 *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* (CEC 2009b, p.20):

> When one resource is added to the system, all else being held equal, another resource will generate less power. If the new resource has a lower cost or fewer emissions than the existing resource mix, the aggregate system characteristics will change to reflect the cheaper power and lower GHG emissions rate.

Net GHG emissions for the integrated electric system will decline when new renewable power plants are added to: 1) move renewable generation towards the 33 percent

target; 2) improve the overall efficiency, or GHG emission rate, of the electric system; or 3) serve load growth or capacity needs more efficiently, or with fewer GHG emissions.

The Role of ISEGS in Renewables Goals/Load Growth

As California moves towards an increased reliance on renewable energy, non-renewable energy resources maybe curtailed or displaced. These potential reduction in non-renewable energy, shown in **Greenhouse Gas Table 4**, could be as much as 36,000 GWh. These assumptions are conservative in that the forecasted growth in retail sales assumes that the impacts of planned increases in expenditures on (uncommitted) energy efficiency are already embodied in the current retail sales forecast[15]. If, for example, forecasted retail sales in 2020 were lowered by 10,000 GWh due to the success of increased energy efficiency expenditures, non-renewable energy needs fall by an additional 6,700 to 8,000 GWh/year, depending on the RPS level, totaling as much as 45,000 GWh per year of reduced non-renewable energy, depending on the RPS assumed.

Greenhouse Gas Table 4
Estimated Changes in Non-Renewable Energy Potentially Needed to Meet California Loads, 2008-2020

California Electricity Supply	**Annual GWh**	
Statewide Retail Sales, 2008, estimated [a]	265,185	
Statewide Retail Sales, 2020, forecast [a]	308,070	
Growth in Retail Sales, 2008-20	42,885	
Growth in Net Energy for Load [b]	46,316	
California Renewable Electricity	**GWh @ 20% RPS**	**GWh @ 33% RPS**
Renewable Energy Requirements, 2020 [c]	61,614	101,663
Current Renewable Energy, 2008	29,174	
Change in Renewable Energy-2008 to 2020 [c]	32,440	72,489
Resulting Change in Non-Renewable Energy [d]	13,876	(-36,173)

Source: Energy Commission staff 2009.
Notes:
a. Not including 8 percent transmission and distribution losses.
b. Based on 8 percent transmission and distribution losses, or 42,885 GWh x 1.08 = 46,316 GWh.
c. Renewable standards are calculated on retail sales and not on total generation, which accounts for 8 percent transmission and distribution losses.
d. Based on net energy (including 8 percent transmission and distribution losses), not based on retail sales

The Role of ISEGS in Retirements/Replacements

ISEGS would be capable of annually providing 960 GWh of renewable generation to replace resources that are or will likely be precluded from serving California loads. State policies, including GHG goals, are discouraging or prohibiting new contracts and new investments in high GHG-emitting, such as coal-fired, generation, generation that relies on water for once-through cooling, and aging power plants (CEC 2007). Some of the

[15] The extent to which uncommitted energy efficiency savings are already represented in the current Energy Commission demand forecast is a subject of study for the 2009 IEPR.

existing plants that are likely to require substantial capital investments to continue operation in light of these policies may be unlikely to undertake the investments and will retire or be replaced.

Replacement of High GHG-Emitting Generation

High GHG -emitting resources, such as coal, are effectively prohibited from entering into new contracts for California electricity deliveries as a result of the Emissions Performance Standard adopted in 2007 pursuant to SB 1368. Between now and 2020, more than 18,000 GWh of energy procured by California utilities under these contracts will have to reduce GHG emissions or be replaced; these contracts are presented in **Greenhouse Gas Table 5**.

Greenhouse Gas Table 5
Expiring Long-term Contracts with Coal-fired Generation 2009 – 2020

Utility	Facility [a]	Contract Expiration	Annual GWh Delivered to CA
PG&E, SCE	Misc In-state Qual.Facilities [a]	2009-2019	4,086
LADWP	Intermountain	2009-2013	3,163 [b]
City of Riverside	Bonanza, Hunter	2010	385
Department of Water Resources	Reid Gardner	2013 [c]	1,211
SDG&E	Boardman	2013	555
SCE	Four Corners	2016	4,920
Turlock Irrigation District	Boardman	2018	370
LADWP	Navajo	2019	3,832
		TOTAL	18,522

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.
Notes:
a. All facilities are located out-of-state except for the Miscellaneous In-state Qualifying Facilities.
b. Estimated annual reduction in energy provided to LADWP by Utah utilities from their entitlement by 2013.
c. Contract not subject to Emission Performance Standard, but the Department of Water Resources has stated its intention not to renew or extend.

This represents almost half of the energy associated with California utility contracts with coal-fired resources that will expire by 2030. If the State enacts a carbon adder[16], all the coal contracts (including those in **Greenhouse Gas Table 5**, which expire by 2020 and, other contracts that expire beyond 2020 and are not shown in the table) may be retired at an accelerated rate as coal-fired energy becomes uncompetitive due to the carbon adder or the capital needed to capture and sequester the carbon emissions. Also shown are the approximate 500 MW of in-state coal and petroleum coke-fired capacity that may be unlikely to contract with California utilities for baseload energy due to SB1368 Emission Performance Standard. As these contracts expire, new and existing generation resources will replace the lost energy and capacity. Some will come from renewable generation; some will come from new and existing natural gas fired

[16] A carbon adder or carbon tax is a specific value added to the cost of a project for per ton of associated carbon or carbon dioxide emissions. Because it is based on, but not limited to, actual operations and emission and can be trued up at year end, it is considered a simple mechanism to assign environmental costs to a project.

generation. All will emit substantially less GHG than the coal and petroleum coke-fired generation, which average about 1.0 $MTCO_2$/MWh without carbon capture and sequestration, resulting in a net reduction in GHG emissions from the California electricity sector.

Retirement of Generation Using Once-Through Cooling

The State Water Resource Control Board (SWRCB) has proposed substantial changes to OTC units, shown in **Greenhouse Gas Table 6**, which would likely require retrofit, retirement, or substantial curtailment of dozens of generating units. In 2008, these units collectively produced about 58,000 GWh. While those OTC facilities owned and operated by utilities and recently-built combined cycles may well install dry or wet cooling towers, it is unlikely that the aging, merchant plants will do so. Most of these units operate at low capacity factors, suggesting a limited ability to compete in the current electricity market. Although the timing would be uncertain, new resources would out-compete aging plants and would displace the energy provided by OTC facilities and likely accelerate the retirements.

Any additional costs associated with complying with the SWRCB regulation would be amortized over a limited revenue stream today and into the foreseeable future. Their energy and much of their dispatchable, load-following capability will have to be replaced. These units constitute over 15,000 MW of merchant capacity and 17,800 GWh of merchant energy. Of this, much but not all of the capacity and energy are in local reliability areas, requiring a large share of replacement capacity – absent transmission upgrades – to locations in the same local reliability area. **Greenhouse Gas Table 6** provides a summary of the utility and merchant energy supplies affected by the OTC regulations.

New generation resources that can either provide local support or energy will emit substantially less GHGs. Existing aging and OTC natural gas generation average 0.6 to 0.7 MTCO2/MWh, which is much higher than a renewable project like ISEGS. When a project can provide energy and capacity, given its location, it can provide a net reduction in GHG emissions from the California electricity sector. A project like ISEGS located far from the coastal load pockets like the Greater Los Angeles Local Capacity Area, would more likely provide energy support to facilitate the retirement of some aging and/or OTC power plants, but would not likely provide any local capacity support at or near the coastal OTC units.

Greenhouse Gas Table 6
Units Utilizing Once-Through Cooling: Capacity and 2008 Energy Output [a]

Plant, Unit Name	Owner	Local Reliability Area	Aging Plant?	Capacity (MW)	2008 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Diablo Canyon 1, 2	Utility	None	No	2,232	17,091	Nuclear
San Onofre 2, 3	Utility	L.A. Basin	No	2,246	15,392	Nuclear
Broadway 3 [b]	Utility	L.A. Basin	Yes	75	90	0.648
El Centro 3, 4 [b]	Utility	None	Yes	132	238	0.814
Grayson 3-5 [b]	Utility	LADWP	Yes	108	150	0.799
Grayson CC [b]	Utility	LADWP	Yes	130	27	0.896
Harbor CC	Utility	LADWP	No	227	203	0.509
Haynes 1, 2, 5, 6	Utility	LADWP	Yes	1,046	1,529	0.578
Haynes CC [c]	Utility	LADWP	No	560	3,423	0.376
Humboldt Bay 1, 2 [a]	Utility	Humboldt	Yes	107	507	0.683
Olive 1, 2 [b]	Utility	LADWP	Yes	110	11	1.008
Scattergood 1-3	Utility	LADWP	Yes	803	1,327	0.618
Utility-Owned				7,776	39,988	0.693
Alamitos 1-6	Merchant	L.A. Basin	Yes	1,970	2,533	0.661
Contra Costa 6, 7	Merchant	S.F. Bay	Yes	680	160	0.615
Coolwater 1-4 [b]	Merchant	None	Yes	727	576	0.633
El Segundo 3, 4	Merchant	L.A. Basin	Yes	670	508	0.576
Encina 1-5	Merchant	San Diego	Yes	951	997	0.674
Etiwanda 3, 4 [b]	Merchant	L.A. Basin	Yes	666	848	0.631
Huntington Beach 1, 2	Merchant	L.A. Basin	Yes	430	916	0.591
Huntington Beach 3, 4	Merchant	L.A. Basin	No	450	620	0.563
Mandalay 1, 2	Merchant	Ventura	Yes	436	597	0.528
Morro Bay 3, 4	Merchant	None	Yes	600	83	0.524
Moss Landing 6, 7	Merchant	None	Yes	1,404	1,375	0.661
Moss Landing 1, 2	Merchant	None	No	1,080	5,791	0.378
Ormond Beach 1, 2	Merchant	Ventura	Yes	1,612	783	0.573
Pittsburg 5-7	Merchant	S.F. Bay	Yes	1,332	180	0.673
Potrero 3	Merchant	S.F. Bay	Yes	207	530	0.587
Redondo Beach 5-8	Merchant	L.A. Basin	Yes	1,343	317	0.810
South Bay 1-4	Merchant	San Diego	Yes	696	1,015	0.611
Merchant-Owned				15,254	17,828	0.605
Total In-State OTC				23,030	57,817	

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.
a. OTC Humboldt Bay Units 1 and 2 are included in this list. They must retire in 2010 when the new Humboldt Bay Generating Station (not ocean-cooled), currently under construction, enters commercial operation.
b. Units are aging but are not OTC.

Closure and Decommissioning

Eventually the facility will 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 to operate and thus impacts associated with those greenhouse gas emissions would no longer occur. The only other expected, albeit temporary, GHG emissions would be equipment exhaust (off-road and on-road) from the dismantling activities. These activities would be of much a shorter duration than construction of the project, equipment are assumed to have

lower comparative GHG emissions due to technology advancement, and 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. Therefore, while there will be a temporary adverse greenhouse gas CEQA impacts during decommissioning they are expected to be less than significant.

ALTERNATIVE 1 – NO ACTION ALTERNATIVE

In the No Project / No Action Alternative, the proposed action would not be undertaken. The BLM land on which the project is proposed would continue to be managed within BLM's framework of a program of multiple use and sustained yield, and the maintenance of environmental quality [43 U.S.C. 1781 (b)] in conformance with applicable statutes, regulations, policy and land use plan.

The results of the No Project / No Action Alternative would be the following:

- The impacts of the proposed project would not occur. However, the land on which the project is proposed would become available to other uses that are consistent with BLM's land use plan, including another solar project.
- The benefits of the proposed project in displacing fossil fuel fired generation and reducing associated greenhouse gas emissions from gas-fired generation would not occur. Both State and Federal law support the increased use of renewable power generation.

If this project is not approved, renewable projects would likely be developed on other sites in the Mojave Desert or in adjacent states as developers strive to provide renewable power that complies with utility requirements and State/Federal mandates. For example, there are two large solar projects proposed on BLM land in California and Nevada within a few miles of the Ivanpah site. In addition, there are currently 70 applications for solar projects covering 575,155 acres pending with BLM in the California Desert District.

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 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 project alone would not be sufficient to change global climate, but would emit greenhouse gases 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

ISEGS, as a solar energy generation project, is exempt from the mandatory GHG emission reporting requirements for electricity generating facilities as currently required by the California Air Resources Board (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).

Since this power project would be permitted for less than a 60% annual capacity factor, the project is not subject to the requirements of SB 1368 and the Emission Performance Standard.

NOTEWORTHY PUBLIC BENEFITS

Greenhouse gas 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.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

No public or agency comments were received on the PSA GHG analysis. An intervenor, Basin and Range Watch (BRW) did provide two comments[17] related to greenhouse gases.

BRW Comment 3

This comment notes that deserts have recently been found to be stronger carbon sinks than previously thought and questions whether the project would reduce GHG emissions at a rate equal to or more than the project caused reduction in biological and non-biological carbon uptake in the project area.

Staff Response

Air quality staff cannot answer the question of how much the natural carbon uptake, biological or non-biological, at the project site might diminish due to this project. However, staff can try to determine the amount of carbon that would be displaced by the project. The following provides a comparison of the CO_2 emissions from the proposed ISEGS and approximate typical range of CO_2 emissions from other types of power plants:

Type of Power Plant	GHG Emission Performance MTCO2/MW
ISEGS	0.029
Natural Gas Combined Cycle	0.370 to 0.430
Natural Gas Fired Boiler	0.550 to 0.650
Natural Gas Peaking Turbine	0.550 to 0.900
Coal Fired Boiler	~1.000

[17] The comments have been paraphrased for brevity and clarity.

The difference in CO_2 emissions, depending on what type of energy source is displaced and given the anticipated annual generation of 960,000 MWh per year for ISEGS, would be on the order of 330,000 to 930,000 metrics tons per year of CO_2 emissions reduced through displacement of fossil fuel fired energy. To put this in perspective, the CO_2 emissions displaced per acre of disturbed land, the project would disturb 4,065 acres, would be on the order of 80 to 230 metric tons of CO_2 and 22 to 62 metric tons of carbon per year per disturbed acre. Converting these units to those used in the comment's cited journal paper (grams of carbon per cubic meter – g/m^3), provides on the order of 5,400 to 15,500 g/m^3 of displaced carbon per year. This is well over the values of annual desert carbon uptake, which ranged from 62 to 622 g/m^3 for all measurements and was noted to be 100 g/m^3 for measurements in the Mojave Desert. Therefore, it is concluded that the project would reduce GHG emissions at a rate that is much greater than any increase the project would cause due to a reduction in natural CO_2 uptake at the project site.

BRW Comment 17

This comment noted concern over the 90 jobs and the GHG emissions from commuting to the job site and questioned whether worker would be required to drive electric cars.

Staff Response

The Energy Commission does not have the authority to require private individuals to purchase or use specific types of vehicles. Additionally, the GHG emissions for these 90 workers is conservatively estimated to impact total plant GHG emission performance by only 0.001 MTCO2/MWh. Staff also notes that the integration of renewable energy resources will often include the siting of remote generation facilities that have both comparatively high staffing requirements and travel distance requirements. Staff has concluded that no additional measures, beyond those already included in the Air Quality section and Traffic and Transportation section, are necessary to mitigate this impact.

CONCLUSIONS

The Ivanpah Solar Electric Generating System project would emit considerably less greenhouse gases (GHG) 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 project would lead to a net reduction in GHG emissions across the electricity system that provides energy and capacity to California. Thus, staff believes that the project would result in a cumulative overall reduction in GHG emissions from the state's power plants, would not worsen current conditions, and would thus not result in CEQA impacts that are cumulatively significant.

Staff does not believe that the GHG emission increases typical from construction activities would be CEQA significant for several reasons. First, the period of construction would be short-term and not ongoing during the life of the project. Additionally, 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 greenhouse gas emissions since staff believes that the use of newer equipment will 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. For all these reasons, staff would likely conclude that the short-term emission of greenhouse gases during construction would be sufficiently reduced and would, therefore, not be CEQA significant.

The Ivanpah Solar Electric Generating System project, as a solar project with a nightly shutdown will operate less than 60% of capacity and is therefore not subject to the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard. However, the Ivanpah Solar Electric Generating System project would easily meet the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard.

MITIGATION MEASURES/PROPOSED CONDITIONS OF CERTIFICATION

No Conditions of Certification related to Greenhouse Gas emissions are proposed. The project owner would comply with any future applicable GHG regulations formulated by the ARB, such as GHG reporting or emissions cap and trade markets.

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