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EXHIBIT 303

ADDENDUM TO STAFF ASSESSMENT: REVISED AIR QUALITY AND CULTURAL RESOURCES TESTIMONY

1. Staff's revised Air Quality testimony reflects the San Joaquin Valley Air Pollution Control District's Final Determination of Compliance, dated January 22, 2010.

2. Staff's revised Cultural Resources testimony reflects the results of the Applicant's pre-certification geoarchaeological study, "Geochronological Investigations of the Proposed Lodi Energy Site, Lodi, California," dated January 27, 2010. The revisions apply only to Staff's Conditions of Certification.

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AIR QUALITY

Testimony of Brewster Birdsall, P.E., QEP

SUMMARY OF CONCLUSIONS

Staff finds that with the adoption of the attached conditions of certification, the proposed Lodi Energy Center (LEC) project would not result in significant air quality related impacts. Staff has also determined that the Lodi Energy Center project would conform with applicable federal, state and San Joaquin Valley Air Pollution Control District (SJVAPCD or District) air quality laws, ordinances, regulations, and standards (LORS). This is an updated version of the Staff Assessment released in November 2009 that reflects the District's final review of the project. The Final Determination of Compliance was released to the public dated January 22, 2010, and this assessment reflects the District's final conditions.

Staff finds that mitigation would be provided in the form of emission reduction credits (ERCs) as required by District rules, to fully offset all nonattainment pollutants and their precursors at a minimum ratio of one-to-one, and to reduce the potential impacts of the proposed project to less than significant.

Global climate change and greenhouse gas emissions from the project are analyzed in **AIR QUALITY APPENDIX AIR-1**. The LEC project would emit approximately 0.38 metric tonnes of carbon dioxide per megawatt hour (MTCO2/MWh). At these levels, the project would comply with the limits of SB 1368 (Perata, Chapter 598, Statutes of 2006) and the greenhouse gas Emission Performance Standard for base load power plants seeking contracts with California's utilities. Mandatory reporting of the GHG emissions would occur while the Air Resources Board develops greenhouse gas regulations and/or trading markets. The project may be subject to GHG reduction or trading requirements as the GHG regulations become more fully developed and implemented.

INTRODUCTION

This analysis evaluates the expected air quality impacts from the emissions of criteria air pollutants from both the construction and operation of the LEC project. Criteria air pollutants are defined as air contaminants for which the state and/or federal government has 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). Two subsets of particulate matter are inhalable particulate matter (less than 10 microns in diameter) (PM10) and fine particulate matter (less than 2.5 microns in diameter) (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 and analyzed in the context of cumulative impacts (**AIR QUALITY APPENDIX AIR-1**).

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

- Whether the LEC project is likely to conform with applicable federal, state, and SJVAPCD air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- Whether the LEC 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); and
- 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)).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws and policies pertain to the control of criteria pollutant emissions and the mitigation of air quality impacts. Staff's analysis examines the project's compliance with these requirements, shown in **Air Quality Table 1**.

Air Quality Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	**U.S. Environmental Protection Agency**
Federal Clean Air Act Amendments of 1990, Title 40 Code of Federal Regulations (CFR) Part 50	National Ambient Air Quality Standards (NAAQS).
Clean Air Act (CAA) § 160-169A and implementing regulations, Title 42 United State Code (USC) §7470-7491 40 CFR 51 & 52 (Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of pollutants that occur at ambient concentrations that attain the NAAQS. The applicant expects that operation of the facility would not trigger the need for a PSD permit, because annual emissions from the proposed LEC project would be below the trigger levels for a new major stationary source (exceeding 100 tons per year) (NCPA2009b). The PSD program is within the jurisdiction of the U.S. EPA.
CAA §171-193, 42 USC §7501 et seq. (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of specified stationary sources. NSR applies to sources of designated nonattainment pollutants. This requirement is addressed through SJVAPCD Rule 2201.

Applicable Law	Description
40 CFR 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines, New Source Performance Standard (NSPS). Requires the proposed combined cycle system to achieve 15 parts per million (ppm) NOx and achieve fuel sulfur standards.
40 CFR 60, Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Requires monitoring of the natural gas fuel source for the proposed auxiliary boiler.
CAA §401 (Title IV), 42 USC §7651(Acid Rain Program)	Requires reductions in NOx and SO_2 emissions, implemented through the Title V program. This program is within the jurisdiction of the SJVAPCD with U.S. EPA oversight [SJVAPCD Rule 2540].
CAA §501 (Title V), 42 USC §7661(Federal Operating Permits Program)	Establishes comprehensive federal operating permit program for major stationary sources. Application required within one year following start of operation. This program is within the jurisdiction of the SJVAPCD with U.S. EPA oversight [SJVAPCD Rule 2520].
State	**California Air Resources Board and Energy Commission**
California Health & Safety Code (H&SC) §41700 (Nuisance Regulation)	Prohibits discharge of such quantities of air contaminants that cause injury, detriment, nuisance, or annoyance.
H&SC §40910-40930	Permitting of source needs to be consistent with approved clean air plan. The SJVAPCD New Source Review program is consistent with regional air quality management plans.
California Public Resources Code §25523(a); 20 CCR §1752, 2300-2309 (CEC & CARB Memorandum of Understanding)	Requires that Energy Commission decision on AFC include requirements to assure protection of environmental quality.
California Code of Regulations for Off-Road Diesel-Fueled Fleets (13 CCR §2449, et seq.)	General Requirements for In-Use Off-Road Diesel-Fueled Fleets – Requires owners and operators of in-use (existing) off-road diesel equipment and vehicles to begin reporting fleet characteristics to CARB in 2009 and meet fleet emissions targets for diesel particulate matter and NOx in 2010.
Airborne Toxic Control Measure for Idling (ATCM, 13 CCR §2485)	ATCM to Limit Diesel-Fueled Commercial Motor Vehicle Idling – Generally prohibits idling longer than five minutes for diesel-fueled commercial motor vehicles.

Applicable Law	Description
Local	**San Joaquin Valley Air Pollution Control District**
SJVAPCD Rule 2201 (New and Modified Stationary Sources)	Establishes the pre-construction review requirements for new, modified or relocated emission sources, in conformance with NSR to ensure that these facilities do not interfere with progress in attainment of the ambient air quality standards and that future economic growth in the San Joaquin Valley is not unnecessarily restricted. Establishes the requirement to prepare a Preliminary Determination of Compliance (PDOC) and Final Determination of Compliance (FDOC) during District review of an application for a power plant. This regulation establishes Best Available Control Technology (BACT) and emission offset requirements. The LEC project net emission increase of NOx would exceed the federal major modification threshold (40 CFR 51.165). The SJVAPCD classifies the project as a Federal Major Modification for NOx, and public notification requirements are triggered (SJVAPCD2010a).
SJVAPCD Rule 2520 (Federally Mandated Operating Permits)	Establishes the permit application and compliance requirements for the federal Title V federal permit program. LEC must submit an application to modify the existing Title V permit.
SJVAPCD Rule 2540 (Acid Rain Program)	Implements the federal Title IV Acid Rain Program, which requires subject facilities to obtain emission allowances for SOx emissions and requires fuel sampling and/or continuous monitoring to determine SOx and NOx emissions.
SJVAPCD Regulation IV (Prohibitions)	Sets forth the restrictions for visible emissions, odor nuisance, various air emissions, and fuel contaminants. Regulation IV incorporates the NSPS provisions of 40 CFR 60, including standards for stationary combustion turbines (Subpart KKKK). These rules limit emissions of NOx, VOC, CO, particulate matter, and sulfur compounds.
SJVAPCD Rules 4306 and 4320 (Boilers, Steam Generators and Process Heaters)	Limits NOx and CO emissions from boilers, steam generator and process heaters. The proposed auxiliary boiler is subject to NOx limit of 9 parts per million by volume (ppmv) and CO limit of 400 ppmv.
SJVAPCD Rule 4703 (Stationary Gas Turbines)	Limits the proposed stationary gas turbine emissions of NOx to 5 ppmv over a 3-hour averaging period and CO to 25 ppmv. Provided certain demonstrations are made, the emission limits do not apply during startup, shutdown, or reduced load periods (defined as "transitional operation periods").
SJVAPCD Regulation VIII (Fugitive PM10 Prohibition)	Requires control of fugitive PM10 emissions from various sources.

SETTING

CLIMATE AND METEOROLOGY

The climate in California is typically dominated by the eastern Pacific high pressure system centered off the coast of California. In the summer, this system results in low inversion layers and clear skies inland and typically early morning fog by the coast. In winter, this system promotes wind and rainstorms originating in the Gulf of Alaska and striking Northern California.

The climate of the San Joaquin Valley is characterized by hot dry summers and mild winters with precipitation almost exclusively in the winter. Very little precipitation occurs during the summer months because the Pacific high pressure blocks migrating storm systems. Beginning in the fall and continuing through the winter, the storm belt and zone of strong westerly winds begins to greatly influence California. Temperature, winds, and rainfall are variable during fall and winter months, and stagnant conditions occur more frequently than during summer.

Wind speeds are generally higher in summer than in winter and are typically north-northwesterly winds. During the spring, summer, and fall, the stronger winds are caused by a combination of offshore and thermal low pressure resulting from high temperatures in the Central Valley. During the winter months, winds are more variable and are predominantly northerly. Calm conditions occur more during winter, but are relatively infrequent throughout the year. Valley fog often occurs during these calm, stagnant atmospheric conditions, when temperature inversions trap a layer of cool, moist air near the surface. The annual average rainfall in Lodi is 17.2 inches and most precipitation (81%) occurs during November through March. Long-term average temperature and precipitation data from the nearest meteorological station located in Lodi, approximately 5.7 miles east-northeast of the project site, indicates that July is the warmest month of the year, with a normal daily maximum and minimum of 91°F and 56°F. In the winter, December and January are the coldest month of the year, with an average daily maximum and minimum of 54°F and 37°F (WRCC 2009).

Along with the wind flow, atmospheric stability and mixing heights are important factors in the determination of pollutant dispersion. Atmospheric stability is an indicator of the air turbulence and mixing. During the daylight hours of the summer when the earth is heated and air rises, there is more turbulence, more mixing, and thus less stability. During these conditions there is more air pollutant dispersion and therefore usually reduced air quality impacts near any single air pollution source. During the winter months between storms, however, very stable atmospheric conditions occur, resulting in very little mixing. Under these conditions, minimal air pollutant dispersion occurs, and consequently higher air quality impacts may result near sources. Because lower mixing heights generally occur during the winter, along with lower mean wind speeds and less vertical mixing, dispersion occurs less rapidly.

AMBIENT AIR QUALITY STANDARDS

The United States Environmental Protection Agency (U.S. EPA) and the California Air Resource Board (ARB) have both established allowable maximum ambient concentrations of criteria air pollutants, based upon public health impacts called ambient air quality standards. The California Ambient Air Quality Standards (CAAQS), established by ARB, are typically lower (more stringent) than the federally established National Ambient Air Quality Standards (NAAQS). The federal Clean Air Act requires the periodic review of the science upon which the standards are based and the standards themselves.

Ambient air quality standards are designed to protect people who are most susceptible to respiratory distress such as asthmatics, the elderly, very young children, people already weakened by other disease or illness, and people engaged in strenuous work or exercise. The ambient standards are also set to protect public welfare, including protection against decreased visibility, and damage to animals, crops, vegetation, and buildings.

Current state and federal air quality standards are listed in **Air Quality Table 2**. The averaging times for the various air quality standards (the duration over which all measurements taken are averaged) range from one hour to one year. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per unit volume of air, in milligrams (mg or 10^{-3} g) or micrograms (µg or 10^{-6} g) of pollutant in a cubic meter (m^3) of ambient air, drawn over the applicable averaging period.

Air Quality Table 2
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	California Standard	Federal Standard
Ozone (O_3)	1 Hour	0.09 ppm (180 µg/m^3)	None
	8 Hour	0.070 ppm (137 µg/m^3)	0.075 ppm (147 µg/m^3)
Respirable Particulate Matter (PM10)	24 Hour	50 µg/m^3	150 µg/m^3
	Annual	20 µg/m^3	None
Fine Particulate Matter (PM2.5)	24 Hour	None	35 µg/m^3
	Annual	12 µg/m^3	15 µg/m^3
Carbon Monoxide (CO)	1 Hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)
	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
Nitrogen Dioxide (NO_2)	1 Hour	0.18 ppm (339 µg/m^3)	None
	Annual	0.030 ppm (57 µg/m^3)	0.053 ppm (100 µg/m^3)
Sulfur Dioxide (SO_2)	1 Hour	0.25 ppm (655 µg/m^3)	None
	3 Hour	None	0.5 ppm (1300 µg/m^3)
	24 Hour	0.04 ppm (105 µg/m^3)	0.14 ppm (365 µg/m^3)
	Annual	None	0.03 ppm (80 µg/m^3)

Source: ARB (http://www.arb.ca.gov/research/aaqs/aaqs2.pdf), November 2008.

The California Air Resources Board and the U.S. EPA designate regions where ambient air quality standards are not met as “nonattainment areas.” Where a pollutant exceeds standards, the federal and state Clean Air Acts both require air quality management plans that demonstrate how the standards will be achieved. These laws also provide the basis for implementing agencies to develop mobile and stationary source performance standards.

EXISTING AMBIENT AIR QUALITY

Air Quality Table 3 summarizes the attainment status of the air quality in the San Joaquin Valley. Violations of federal and state ambient air quality standards for ozone, particulate matter, and CO have occurred historically throughout the region. Since the early 1970s, substantial progress has been made toward controlling these pollutants. Although air quality improvements have occurred, violations of standards for particulate matter and ozone persist.

Air Quality Table 3
Attainment Status of San Joaquin Valley Air Pollution Control District

Pollutants	Federal Classification	State Classification
Ozone (1-hr)	No Federal Standard	**Nonattainment (Severe)**
Ozone (8-hr)	**Nonattainment (Serious)** [a]	**Nonattainment**
PM10	Attainment [b]	**Nonattainment**
PM2.5	**Nonattainment**	**Nonattainment**
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment

Source: SJVAPCD 2008 (http://www.valleyair.org/aqinfo/attainment.htm).
Notes:
[a] In April 2007, the SJVAPCD Governing Board proposed to re-classify the region as “extreme” nonattainment, and the U.S. EPA is reviewing the request.
[b] In November 2008, EPA redesignated the San Joaquin Valley to attainment for the PM10 National Ambient Air Quality Standard (NAAQS) and approved the PM10 Maintenance Plan.

Nonattainment Criteria Pollutants

Air Quality Table 4 summarizes the existing ambient monitoring data for nonattainment criteria pollutants (ozone and particulate matter) collected by ARB and SJVAPCD from monitoring stations closest to the project site. Data marked in **bold** indicates that the most-stringent current standard was exceeded. Note that an exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.

Air Quality Table 4
LEC, Highest Measured Concentrations (ppm or μg/m^3)

Pollutant	Averaging Time	2003	2004	2005	2006	2007	2008
Ozone (ppm)	1 hour	**0.104**	**0.096**	**0.099**	**0.109**	**0.093**	**0.105**
Ozone (ppm)	8 hour	**0.088**	**0.08**	**0.086**	**0.092**	**0.081**	**0.090**
PM10 (μg/m^3)	24 hour	**88**	**60**	**79**	**82**	**71**	**104.5**
PM10 (μg/m^3)	Annual	**28.4**	**29.4**	**29.8**	**33.4**	**27.7**	**31.2**
PM2.5 (μg/m^3)	24 hour	**45**	**41**	**63**	**47**	**52**	**81.2**
PM2.5 (μg/m^3)	Annual	**13.6**	**13.2**	**12.5**	**13.1**	**12.9**	**14.4**

Source: ARB, Air Quality Data Statistics (http://www.arb.ca.gov/adam/welcome.html). Accessed June 2009.
Notes: Monitoring Station for ozone, PM10, and PM2.5: 2003-2008: Stockton-Hazelton Street.

Ozone

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between precursor air pollutants. The primary ozone precursors are NOx and VOC, which interact in the presence of sunlight and warm air temperatures to form ozone. Ozone formation is highest in the summer and fall when abundant sunshine and high temperatures trigger the necessary photochemical reactions, and lowest in the winter. The days with the highest ozone concentrations commonly occur between June and August, but the region's ozone management season officially runs from April through November (the second and third calendar quarters, Q2 and Q3).

Respirable Particulate Matter (PM10)

PM10 is a mixture of particles and droplets that vary in size and chemical composition, depending upon the origin of the pollution. An extremely wide range of sources, including natural causes, most mobile sources, and many stationary sources, causes emissions that directly and indirectly lead to increased ambient particulate matter. This makes it an extremely difficult pollutant to manage. Particulate matter caused by any combustion process can be generated directly by burning the fuel, but it can also be formed downwind when various precursor pollutants chemically interact in the atmosphere to form solid precipitates. These solids are called secondary particulate matter since the contaminants are not directly emitted, but are rather indirectly formed as a result of precursor emissions.

Gaseous contaminants such as NOx, SO_2, organic compounds, and ammonia (NH_3) from natural or man-made sources can form secondary particulate nitrates, sulfates, and organic solids. Secondary particulate matter is mostly finer PM10, whereas particles from dust sources tend to be the coarser fraction of PM10.

Air Quality Table 5 summarizes the ambient PM10 data collected from the nearest monitoring station to the project site and the highest PM10 concentrations in the District.

Air Quality Table 5
LEC, Highest Measured PM10 Concentrations (µg/m^3)

Location	Averaging Time	2003	2004	2005	2006	2007	2008
Bethel Island-Contra Costa	24 hour	49.9	40.0	**61.8**	**82.1**	46.7	**78.2**
	Days Over CAAQS	6	0	6	6	0	18
	Days Over NAAQS	0	0	0	0	0	0
	Annual	19.4	19.5	18.5	19.4	18.8	**24.1**
Stockton-Hazelton Street	24 hour	**88**	**60**	**79**	**82**	**71**	**104.5**
	Days Over CAAQS	17	18	47	63	24	49
	Days Over NAAQS	0	0	0	0	0	0
	Annual	**28.4**	**29.4**	**29.8**	**33.4**	**27.7**	**31.2**
District-wide	24 hour	**150**	**217**	**131**	**304**	**172**	**351**
	Days Over CAAQS	167	113	146	167	145	N/A
	Days Over NAAQS	0	1	0	4	1	18
	Annual	**52.4**	**47.9**	**44.3**	**55.4**	**54.8**	**52.4**

Source: ARB, Air Quality Data Statistics (http://www.arb.ca.gov/adam/welcome.html). Accessed June 2009.
Note: Concentrations shown are based upon California reference methods. The number of days above the CAAQS (50 µg/m^3) is calculated by ARB. Because PM10 is monitored approximately once every six days, the potential number of violation days is calculated by multiplying the actual number of days of violations by six.

Air Quality Table 5
LEC, Highest Measured PM10 Concentrations (µg/m^3)

Location	Averaging Time	2003	2004	2005	2006	2007	2008
Bethel Island-Contra Costa	24 hour	49.9	40.0	**61.8**	**82.1**	46.7	**78.2**
	Days Over CAAQS	6	0	6	6	0	18
	Days Over NAAQS	0	0	0	0	0	0
	Annual	19.4	19.5	18.5	19.4	18.8	**24.1**
Stockton-Hazelton Street	24 hour	**88**	**60**	**79**	**82**	**71**	**104.5**
	Days Over CAAQS	17	18	47	63	24	49
	Days Over NAAQS	0	0	0	0	0	0
	Annual	**28.4**	**29.4**	**29.8**	**33.4**	**27.7**	**31.2**
District-wide	24 hour	**150**	**217**	**131**	**304**	**172**	**351**
	Days Over CAAQS	167	113	146	167	145	N/A
	Days Over NAAQS	0	1	0	4	1	18
	Annual	**52.4**	**47.9**	**44.3**	**55.4**	**54.8**	**52.4**

Source: ARB, Air Quality Data Statistics (http://www.arb.ca.gov/adam/welcome.html). Accessed June 2009.
Note: Concentrations shown are based upon California reference methods. The number of days above the CAAQS (50 µg/m^3) is calculated by ARB. Because PM10 is monitored approximately once every six days, the potential number of violation days is calculated by multiplying the actual number of days of violations by six.

PM10 is primarily a winter problem, but high regional PM10 levels occur at other times of the year as well. Days with high PM10 concentrations commonly occur in November and December, but the region's PM10 management season officially runs from October through March (the first and fourth calendar quarters, Q1 and Q4). Northern California wildfires in Monterey County, Santa Clara County, and the Sierra Nevada foothills during June 2008 were probably responsible for the most-recent high PM10 concentrations.

Fine Particulate Matter (PM2.5)

Particles and droplets with an aerodynamic diameter less than or equal to 2.5 microns (PM2.5) penetrate more deeply into the lungs than PM10, so can therefore be much more damaging to public health than larger particles. PM2.5 is mainly a product of combustion and includes nitrates, sulfates, organic carbon (ultra-fine dust), and elemental carbon (ultra-fine soot). Almost all combustion-related particles, including those from wood smoke and cooking, are smaller than 2.5 microns. Nitrate and sulfate particles are formed through complex chemical reactions in the atmosphere. Particulate nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. The nitrate ion concentrations during the winter make up a large portion of the total PM2.5. Ammonium sulfate is also a concern because of the ready availability of ammonia in the atmosphere.

Air Quality Table 6 summarizes the ambient PM2.5 data collected from the nearest monitoring station.

Air Quality Table 6
LEC, Highest Measured PM2.5 Concentrations (μg/m^3)

Location	Averaging Time	2003	2004	2005	2006	2007	2008
Stockton-Hazelton Street	24 hour	**45.0**	**41.0**	**63.0**	**47.0**	**52.0**	**81.2**
	Annual	**13.6**	**13.2**	**12.5**	**13.1**	**12.9**	**14.4**

Source: ARB, Air Quality Data Statistics (http://www.arb.ca.gov/adam/welcome.html). Accessed June 2009.

Attainment Criteria Pollutants

Carbon Monoxide

Carbon monoxide (CO) is a by-product of incomplete combustion common to any fuel-burning source. Ambient concentrations of CO vary substantially depending upon the proximity of the source since the pollutant disperses quickly and oxidizes in the air. Mobile sources are the principal sources of CO emissions, and they have historically been the focus of regional and statewide strategies to attain and maintain CO ambient air quality standards. Ambient CO concentrations attain the standards due to two state-wide programs for all mobile sources: the 1992 wintertime oxygenated gasoline program, and Phases I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also helped reduce CO emissions.

Nitrogen Dioxide

Approximately 90% of the NOx emitted from combustion sources is in the form of nitric oxide, while the balance is NO_2. Nitric oxide (NO) is oxidized in the presence of ozone to form NO_2, but some level of photochemical activity is needed for this conversion. High concentrations of NO_2 occur during the fall (not in the winter) when atmospheric conditions tend to trap ground-level releases but lack significant photochemical activity (less sunlight). In the summer, the conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions (atmospheric unstable conditions) tend to engage the NO in reactions with VOCs to create ozone and also disperse the NO_2. The formation of NO_2 in the summer, with the help of the ozone, is according to the following reaction:

$$NO + O_3 \rightarrow NO_2 + O_2$$

Urban areas typically have high daytime ozone concentrations that drop substantially at night as the above reaction takes place, and ozone scavenges the available NO. If ozone is unavailable to oxidize the NO, less NO_2 will form because the reaction is "ozone-limited." This reaction explains why, in urban areas, ground-level ozone concentrations drop at night, while aloft and in downwind rural areas (without sources of fresh NO emissions), ozone concentrations can remain relatively high.

New CAAQS for NO_2 became effective in early 2008. Although the attainment designations have not yet been established for the new, more stringent standards, the San Joaquin Valley air basin appears likely to attain. Data from 2006 to 2008 shows the highest observed hourly concentration for the entire San Joaquin Valley (0.101 ppm) is well below the new 0.18 ppm NO_2 standard (ARB 2009).

Sulfur Dioxide

Sulfur dioxide is typically emitted as a result of the combustion of fuels containing sulfur. When high levels are present in ambient air, SO_2 leads to sulfite particulate formation and acid rain. Natural gas contains very little sulfur and so therefore results in very little SO_2 emissions when burned. By contrast, high sulfur fuels like coal emit large amounts of SO_2 when burned. Sources of SO_2 emissions come from every economic sector and include a wide variety of gaseous, liquid, and solid fuels. The entire state is designated attainment for all SO_2 ambient air quality standards.

Summary of Existing Ambient Air Quality

The local and recent ambient air quality data show existing violations of ambient air quality standards for ozone, PM10, and PM2.5. Staff uses the highest local (Stockton) background ambient air concentrations as the baseline in staff's analysis of potential ambient air quality impacts for the proposed LEC project. Data from the nearest site in Stockton is used for CO and NO_2, and the Bethel Island site is used for SO_2. The highest concentrations are shown in **Air Quality Table 7**.

Air Quality Table 7
LEC, Highest Local Background Concentrations
Used in Staff Assessment (μg/m³)

Pollutant	Averaging Time	Background	Limiting Standard	Percent of Standard
PM10	24 hour	**104.5**	50	**209**
	Annual	**33.4**	20	**167**
PM2.5	24 hour	**81.2**	35	**232**
	Annual	**14.4**	12	**120**
CO	1 hour	5,500	23,000	24
	8 hour	2,640	10,000	26
NO_2	1 hour	147	339	43
	Annual	34	57	60
SO_2	1 hour	46.9	655	7
	24 hour	18.3	105	17
	Annual	5.2	80	7

Source: AFC Table 5.1-28, updated with ARB 2009.
Note that an exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.

Existing Emissions

The proposed Lodi Energy Center (LEC) facility would be located in Lodi, San Joaquin County, California, on a 4.4-acre parcel located adjacent to the city of Lodi's White Slough Water Pollution Control Facility (WPCF) and the Northern California Power Agency (NCPA) Combustion Turbine Project #2 (STIG plant). The equipment at the existing NCPA STIG plant consists of one 49 MW General Electric (GE) LM-5000 natural gas-fired, steam-injected combustion turbine generator (permitted heat input capacity of 463 million British thermal units per hour [MMBtu/hr], Response to DR59, CH2M2009g), and one 240 HP Cummins diesel fire pump engine. There is also a small cooling tower for the STIG plant, which would be relocated to accommodate the proposed LEC plant.

NCPA would be a common owner and operator of the existing STIG plant and the proposed LEC plant, therefore some existing facilities would be shared between the two plants as following.

Shared Existing Facilities:

- The anhydrous ammonia system, including both the 12,000-gallon storage tank and unloading facilities;
- The 230-kilovolt (kV) switchyard and interconnect;
- The fire systems, including fire water storage tanks and diesel-fired emergency fire pump engine;

- The domestic water systems, including eye wash stations and emergency showers; and
- The existing Class I underground injection well (to be used for backup only).

The existing STIG plant CTG and fire pump engine currently operate on an as-needed basis, with an annual capacity factor of about 20% (1,800 hours annually) for each recent year (Response to DR58, CH2M2009g). **Air Quality Table 8** summarizes the allowable (permitted) emissions for the existing STIG plant and the average actual emissions including 2006, 2007, and the first nine months of 2008.

Air Quality Table 8
Existing NCPA STIG Plant, Allowable Emissions and Actual Emissions (lb/yr)

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
Existing Allowable Emissions	**20.4**	**25.9**	**8.8**	**58.8**	**5.7**
Existing STIG Plant 2006	3.7	3.4	1.4	3.8	0.2
Existing STIG Plant 2007	3.5	4.3	1.8	4.7	0.2
Existing STIG Plant 2008 (Q1 to Q3)	3.3	4.0	1.7	4.6	0.2

Source: AFC Table 5.1-14 and Responses to DR58 and 59 (CH2M2009g).

PROJECT DESCRIPTION AND PROPOSED EMISSIONS

The proposed LEC combined cycle power plant would include the following stationary sources of emissions (AFC Section 2.1.4 updated by Supplement D, CH2M2009c):

- A stationary natural-gas fired combustion turbine generator (CTG), Siemens “Flex Plant 30” with rapid startup technology, nominal power generation rate of 185 MW at a heat input capacity of 2,142 MMBtu/hr, in a combined-cycle configuration with a heat recovery steam generator (HRSG) that does not use duct firing;
- One condensing steam turbine generator (STG) rated at 95 MW (nominal);
- One 36.5 MMBtu/hr capacity natural gas-fired auxiliary boiler with ultra low NOx burner(s) for maintaining heat in the steam generator and steam turbine;
- A new 7-cell cooling tower; and
- An administration building, including the control room, office space, maintenance shop, warehouse, and communication systems shared by the LEC and STIG plants.

Separate emissions estimates for the proposed project caused during the construction phase, initial commissioning, and operation are described here.

<u>Proposed Construction Emissions</u>

Construction of LEC is expected to take about 24 months. Onsite construction activities include site preparation, foundation work, installation of major equipment, and construction/installation of major structures. During the construction period, air emissions would be generated from the exhaust of off-road/non-road construction equipment and on-road vehicles and fugitive dust from activity on unpaved surfaces and material handling. Construction activities would typically occur between 6 a.m. and 11 p.m., Monday through Saturday (AFC Section 2.2). Additional hours may be necessary to make up schedule deficiencies, or to complete critical construction activities such as pouring concrete at night during hot weather, working around time-critical shutdowns and constraints. The applicant expects to use U.S. EPA Tier 3 certified engines for on-site (offroad) construction equipment larger than 100 horsepower and Tier 2 certified engines for equipment under 100 hp (AFC Appendix 5.1E). During some construction period and during the initial commissioning phase of the project, some activities would continue 24 hours per day, 7 days per week. The project would also include a new 2.5 mile long natural gas pipeline (AFC Section 2.1.8) and a connection to an existing recycled water pipeline (AFC Section 2.1.10). These linear facilities would be constructed in a 2-month window prior to or simultaneously with the construction of the project.

Fugitive dust emissions would result from (AFC Appendix 5.1E.1.1):

- Dust entrained during site preparation and grading/excavation at the construction site;
- Dust entrained during on-site travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations; and
- Wind erosion of soil at areas disturbed during construction activities.

Combustion-related emissions would be the result of:

- Exhaust from the diesel construction equipment used for site preparation, grading, excavation, trenching, and construction of onsite structures;
- Exhaust from water trucks used to control construction dust emissions;
- Exhaust from portable welding machines;
- Exhaust from pickup trucks and diesel trucks used to transport workers and materials around the construction site;
- Exhaust from diesel trucks used to deliver concrete, fuel and construction supplies to the construction site; and
- Exhaust from automobiles used by workers to commute to the construction site.

Estimates for the highest daily emissions and total annual emissions over the 24-month construction period are shown in **Air Quality Table 9**.

Air Quality Table 9
LEC, Estimated Maximum Construction Emissions

Construction Activity	NOx	VOC	PM10	PM2.5	CO	SOx
On-site Construction Equipment (lb/day)	80.6	7.7	4.5	4.5	51.4	0.1
On-site Fugitive Dust (lb/day)	---	---	21.0	4.9	---	---
Off-site (On-road) Worker Travel, Truck Deliveries, Dust (lb/day)	179.5	24.9	8.5	8.5	187.2	0.25
Off-site Linear Facility Equipment and Fugitive Dust (lb/day)	96.8	8.5	10.8	4.8	48.7	0.10
Maximum Daily Construction Emissions (lb/day)	**356.9**	**41.1**	**44.8**	**22.7**	**287.3**	**0.45**
On-site Construction Equipment (tpy)	7.2	0.7	0.4	0.4	4.6	0.01
On-site Fugitive Dust (tpy)	---	---	1.6	0.3	---	---
Off-site (On-road) Worker Travel & Truck Deliveries (tpy)	2.3	1.7	0.2	0.2	17.7	0.02
Off-site Linear Facility Equipment and Fugitive Dust (tpy)	2.1	0.2	0.2	0.1	1.0	<0.01
Peak Annual Construction Emissions (tpy)	**11.6**	**2.6**	**2.4**	**1.0**	**23.3**	**0.03**

Source: AFC Appendix 5.1E Tables 5.1E-1 and 5.1E-2, Attachment 5.1E-1, and Table DR56-8 (CH2M2009g). Worst-case totals assume simultaneous maximum emissions during linear facility construction.
Note: Different activities have maximum emissions at different time during the construction period; therefore, total maximum daily, monthly, and annual emissions might be different from the summation of emissions from individual activities.

Proposed Initial Commissioning Emissions

New electrical generation facilities must go through initial commissioning phases before becoming commercially available to generate electricity. During this period, initial firing causes greater emissions than those that occur during normal operations because of the need to tune the combustor, conduct numerous startups and shutdowns, operate under low loads, and conduct testing before emission control systems are functioning or fine-tuned for optimum performance.

The applicant expects that approximately 292 hours of operation over approximately 28 days would be needed to the accomplish the various following commissioning activities (NCPA2008b):

- Full Speed No Load Tests (FSNL) – a test of the gas turbine ignition system, a test to ensure that the CTG is synchronized with its electric generator, and a test of the CTG's speed control system.
- Steam Blows – steam is passed through the CTG and HRSG to remove all debris that could potentially damage the SCR and oxidation catalysts.

- Minimum Load Tests and Full Load Tests (without SCR Operational) – several days of tuning the CTG combustor to minimize emissions and perform other checks.
- Multiple Load Tests (SCR/Oxidation Catalyst Operational at Various Levels) – several days of installing control systems and tuning to achieve NOx and CO control at design levels.
- Performance Tests (SCR/Oxidation Catalyst at Full Control) – several days of the CTG operating from minimum to maximum load to confirm emissions performance.

Air Quality Table 10 presents the applicant's anticipated maximum hourly and daily short-term emissions of criteria pollutants (CH2M2009c). Maximum hourly and daily emissions for NOx and CO would occur with the gas turbine in the steam blow phase and partial load tests before emission control systems are installed and operational. Emission rates for VOC, PM10, PM2.5, and SOx during initial commissioning are not expected to be higher than normal operating emissions. This is because PM10 and SOx emissions are proportional to fuel use. The total initial commissioning emissions are presented in **Air Quality Table 10.**

Air Quality Table 10
LEC, Maximum Initial Commissioning Emissions (hourly and daily)

Commissioning Source	NOx	VOC	PM10/ PM2.5	CO	SOx
CTG/HRSG (lb/hr)	400.0	16.0	9.0	2,000	6.1
CTG/HRSG (lb/day)	4,000	192	108	20,000	73.1

Source: Table AQ-2, Supplement B for Data Adequacy (NCPA2008b); Table 5.1B-7bR (CH2M2009c).

Operation Emission Controls

NOx Controls

The combustion turbine would use dry low-NOx (DLN) combustors to maintain low levels of NOx formation while ensuring complete combustion of the fuel. Exhaust from each turbine would enter the HRSG and Selective Catalytic Reduction (SCR) system before being released into the atmosphere. SCR refers to a process that chemically reduces NOx to nitrogen (N_2) and water vapor (H_2O) by injecting ammonia (NH_3) into the flue gas stream in the presence of a catalyst and excess oxygen. The process is termed selective because the ammonia preferentially reacts with NOx rather than oxygen. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or noble metals are also used. Regardless of the type of catalyst used, efficient conversion of NOx to nitrogen and water vapor requires the uniform mixing of ammonia into the exhaust gas stream and a catalyst surface large enough to ensure sufficient time for the reaction to take place.

VOC and CO Controls

Emissions of CO and unburned hydrocarbons, including VOC, will be controlled with an oxidation catalyst installed in conjunction with the SCR catalyst. An oxidation catalyst system chemically reacts with organic compounds and CO with excess oxygen to form carbon dioxide (CO_2) and water. Unlike the SCR system for reducing NOx, an oxidation catalyst does not require any additional chemicals.

PM10/PM2.5 and SOx Controls

The exclusive use of pipeline-quality natural gas, a clean-burning fuel that contains very little sulfur or noncombustible solid residue, will limit the formation of SOx and particulate matter. Natural gas does contain small amounts of a sulfur-based scenting compound known as mercaptan, which results in some SOx emissions when burned. However, in comparison with other fossil fuels used in thermal power plants, SOx emissions from natural gas are very low. Particulate matter emissions from natural gas combustion are also very low compared with other fossil fuels. The sulfur content of pipeline-quality natural gas is normally less than 1 grain of sulfur per 100 cubic feet at standard temperature and pressure (gr/100 scf). High-efficiency air inlet filtration and a lube oil vent coalesce would also be used to control particulate emissions.

Proposed Operation Emissions

Air Quality Table 11 through **Air Quality Table 14** summarize the maximum (worst-case) criteria pollutant emissions associated with the LEC project's normal and routine operation. Emissions for the combustion turbine system are based upon:

- NOx emissions controlled to 2.0 parts per million by volume, dry basis (ppmvd) corrected to 15% oxygen, averaged over any 1-hour period;
- VOC emissions controlled to 1.4 ppmvd at 15% O_2 for any 3-hour period;
- CO emissions controlled to 2.0 ppmvd at 15% O_2 for any 3-hour period, revised downward from original proposal of 3.0 ppm (NCPA2009b);
- PM10 emissions at 9.0 lb/hr based on exclusive use of pipeline-quality natural gas fuel with no provisions for an alternative or backup fuel;
- SOx emissions based on hourly or daily levels of fuel sulfur content of up to 1 gr/100 scf;
- A proposal to allow periodic CTG combustor tuning with each duration not to exceed 12 hours, after every 8,000 hours of operation or after 450 starts for replacing components of the combustor that have a limited operational life (Response to DR64, CH2M2009g); and
- CTG firing of 7,824 hours annually including 7,590 hours of normal operation and 234 hours annually in startup mode (for the worst-case NOx, VOC, and CO estimates, per NCPA2009b) with the option of operating up to 8,760 hours annually in steady-state mode (for the worst-case PM10/PM2.5 and SOx estimates) and 4,000 hours per year of operation of the auxiliary boiler.

Air Quality Table 11 lists the maximum hourly emissions from each piece of proposed equipment estimated by the applicant. Emissions for NOx, CO, and VOC during startup and shutdown events would have higher emissions than during normal operation. Since PM10 and SOx emissions are proportional to fuel use, PM10 and SOx have higher emissions rates during full-load operation.

Air Quality Table 11
LEC, Maximum Hourly Emissions Rates (pounds per hour [lb/hr])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
CTG/HRSG	15.54	3.79	9.0	9.46	6.1
CTG/HRSG (maximum during startup)	160	16.00	9.0	900	6.1
CTG/HRSG (typical during startup)	100	---	---	500	---
Auxiliary Boiler	0.31	0.15	0.28	1.34	0.10
Cooling Tower	---	---	0.93	---	---

Source: AFC Table 5.1-21R, Appendix A Table 5.1A-6R (CH2M2009c) and (NCPA2009b).

Air Quality Table 12 lists the worst-case emissions during any given day of operation of the proposed LEC project. Daily combustion turbine emissions for NOx, VOC, and CO are based on six hours in a startup/shutdown mode and 18 hours of full load operation, and for PM10 and SOx daily emissions are based on 24 hours of operation. The auxiliary boiler emissions are based on 24 hours per day (CH2M2009c), and cooling tower emissions are based on 24 hours of operation per day. Emergency fire pump emissions are not estimated in this project analysis, since the existing emergency fire pump of STIG would be shared and unaffected by the proposed LEC project.

Air Quality Table 12
LEC, Maximum Daily Emissions (pounds per day [lb/day])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
CTG/HRSG	879.7	164.3	216.0	5,570.3	146.4
Auxiliary Boiler	7.4	3.7	6.7	32.1	2.5
Cooling Tower	---	---	22.3	---	---
Total Project	887.0	167.9	245.1	5,602.4	148.9

Source: AFC Table 5.1-21R, Appendix A Table 5.1A-6R (CH2M2009c) and independent staff assessment (per NCPA2009b).

Air Quality Table 13 lists maximum potential annual emissions from each source for the proposed project, based on applicant and District calculations reviewed by staff. The operating assumptions include CTG firing for 7,824 hours annually including 234 hours in startup mode (for the worst-case NOx, VOC, and CO estimates) with the option of operating up to 8,760 hours annually in steady-state mode (for the worst-case PM10 and SOx estimates). Auxiliary boiler emissions are based on 4,000 operating hours per year and cooling tower emissions are based on 8,760 operating hours.

Air Quality Table 13
LEC, Maximum Annual Emissions (tons per year [tpy])

Source	NOx	VOC	PM10/ PM2.5	CO	SOx
CTG/HRSG	70.7	16.3	39.4	94.4	26.7
Auxiliary Boiler	0.6	0.3	0.6	2.7	0.2
Cooling Tower	---	---	4.1	---	---
Total Maximum Annual Emissions	**71.3**	**16.6**	**44.1**	**97.1**	**26.9**

Source: Lodi AFC Table 5.1-21R, Appendix A Table 5.1A-6R (CH2M2009c) and independent staff assessment (per NCPA2009b).

Air Quality Table 14 shows the offsite emissions that would be caused by mobile sources accessing the facility. These offsite emissions are based on the assumption that seven new full time workers would be onsite, 365 days per year, and that commuting distances for workers are 50 miles per day per roundtrip. The facility would also require material deliveries, which would occur up to 12 times per week. Roundtrip vehicle miles traveled for material deliveries are estimated to be 50 miles.

Air Quality Table 14
LEC, Annual Offsite Emissions (pounds per year [lb/yr])

Source	NOx	VOC	PM10	PM2.5	CO	SOx
Worker Commutes [a]	113	112	10.9	3.8	1,180	1.1
Material Deliveries [b]	1,180	92	49.0	42.8	440	1.0
Total Annual Emissions (lb/yr)	**1,293**	**204**	**59.9**	**46.6**	**1,620**	**2.1**

Source: Response to DR57 and Attachment DR57-1 (CH2M2009g).
Notes: a. Worker commutes are based on 7 new full time workers, commuting 50 miles daily per roundtrip, 365 days per year.
b. Material deliveries are based on 12 deliveries per week, traveling 50 miles per roundtrip.

Ammonia Emissions

Ammonia is injected into the flue gas stream as part of the SCR system that controls NOx emissions. In the presence of the catalyst, the ammonia and NOx react to form harmless elemental nitrogen and water vapor. However, not all of the ammonia reacts with the flue gases to reduce NOx; a portion of the ammonia passes through the SCR and is emitted unaltered from the stacks. These ammonia emissions are known as ammonia slip.

The applicant proposes to limit ammonia slip emissions from the combined-cycle turbine system to 10 ppmvd. However, Energy Commission staff recommends that combined-cycle systems follow the Air Resources Board recommendation of 5 ppmvd for ammonia slip, established in the Guidance for Power Plant Siting (ARB 1999).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff characterizes air quality impacts as follows: All project emissions of nonattainment criteria pollutants and their precursors (NOx, VOC, CO, PM10, PM2.5, and SOx) are considered significant and must be mitigated. For short-term construction activities that essentially cease before operation of the power plant, our assessment is qualitative and mitigation consists of controlling construction equipment tailpipe emissions and fugitive dust emissions to the maximum extent feasible. For operating emissions, mitigation includes both the Best Available Control Technology (BACT) and emission reduction credits (ERC) or other valid emission reductions to offset emissions of both nonattainment criteria pollutants and their precursors.

The ambient air quality standards used by staff as the basis for characterizing project impacts are health-based standards established by the ARB and U.S. EPA. They are set at levels that contain a margin of safety to adequately protect the health of all people, including those most sensitive to adverse air quality impacts such as the elderly, persons with existing illnesses, children, and infants.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Ambient air quality impacts occur when project emissions cause the ambient concentration of a pollutant to increase. Project-related emissions are the actual mass of emitted pollutants, which are diluted in the atmosphere before reaching the ground. Analysis begins with quantifying the emissions, then uses an atmospheric dispersion model to determine the probable change in ground-level concentrations.

Dispersion models complete the complex, repeated calculations that consider emissions in the context of various ambient meteorological conditions, local terrain, and nearby structures that affect air flow. For the LEC project, the surface meteorological data used as an input to the dispersion model included five years (2000-2004) of hourly wind speeds and directions measured at the Stockton meteorological station, combined with upper-air meteorological data from Oakland International Airport monitoring station. The District released newer meteorological data (2004-2008) in mid-2009 and removed 2001 from the recommended set due to a data deficiency. However, since the 2000-2004 set was the most up-to-date at the time the LEC project application was filed, it is acceptable for this staff assessment. If, as part of the ongoing District review, the 2004-2008 meteorological data must be used, then slightly different project impacts could result.

The applicant conducted the air dispersion modeling based on guidance presented in the *Guideline on Air Quality Models* (EPA, 2005) and the American Meteorological Society/Environmental Protection Agency Regulatory Model known as AERMOD (version 07026) for an analysis of the operating-phase emissions. The U.S. EPA designates AERMOD as a “preferred” model for refined modeling in all types of terrain. For determining NO_2 impacts of short-term emissions (1-hour averaging period), NOx emissions are further modeled using the more-rigorous Plume Volume Molar Ratio Method (PVMRM) adaptation of the Ozone Limiting Method (OLM). Because project NOx emissions would be approximately 90% NO that could oxidize into NO_2 with sufficient time, sunlight, and availability of organic compounds or ozone, use of the PVMRM and OLM is appropriate. Concurrent hourly ozone data from Stockton monitoring station is used in modeling the reactive NOx and NO_2 impacts.

Project-related modeled concentrations are then added to highest background concentrations to arrive at the total impact of the project. The total impact is then compared with the ambient air quality standards for each pollutant to determine whether the project's emissions would either cause a new violation of the ambient air quality standards or contribute to an existing violation.

Construction Impacts and Mitigation

This section discusses the project's short-term direct construction ambient air quality impacts assessed by the applicant and, as necessary, independently assessed by Energy Commission staff. The ambient air quality impacts are modeled using AERMOD, and the impacts for NO_2 are modeled using the ozone limiting method (OLM). Construction modeling for LEC used five years of meteorological data (2000-2004 from Stockton) prepared by SJVAPCD, with concurrent ozone data also from Stockton for modeling reactive NOx and NO_2.

Air Quality Table 15 summarizes the results of the modeling analysis for construction activities. The total impact is the sum of the existing background condition plus the maximum impact predicted by the modeling analysis for project activity. The values in **bold** in the Impact and Background columns represent the values that either equal or exceed the relevant ambient air quality standard.

Air Quality Table 15
LEC, Construction-Phase Maximum Impacts (µg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
PM10	24 hour	35.6	**104.5**	**140.1**	50	**280**
	Annual	4.2	**33.4**	**37.6**	20	**188**
PM2.5	24 hour	10.2	**81.2**	**91.4**	35	**261**
	Annual	1.1	**14.4**	**15.5**	12	**129**
CO	1 hour	210	5,500	5,710.0	23,000	25
	8 hour	94	2,640	2,734.0	10,000	27
NO_2	1 hour [a]	91.6	147	238.6	339	70
	Annual [a]	3.6	34	37.6	57	66
SO_2	1 hour	0.4	46.9	47.3	655	7
	24 hour	0.1	18.3	18.4	105	18
	Annual	0.01	5.2	5.2	80	7

Source: AFC Appendix 5.1E Table 5.1E-4.
Note: a. The maximum 1-hour NO_2 concentration is based on AERMOD OLM output, and the ambient ratio method (ARM) is applied for annual NO_2, using national default 0.75 ratio.

The maximum modeled project construction impacts are predicted to occur near the eastern and western fence lines for the worst 1-hour impacts and at the southern fence line for the 24-hour impacts. For each pollutant, the concentrations would decrease rapidly with distance. The nearest residential receptors are approximately 0.75 miles to the north, not near the fence line.

Staff believes that particulate matter emissions from construction would cause a significant impact because they will contribute to existing violations of PM10 and PM2.5 ambient air quality standards, and additionally that those emissions can and should be mitigated to a level of insignificance. Significant secondary impacts would also occur for PM10, PM2.5, and ozone because construction-phase emissions of particulate matter precursors (including SOx) and ozone precursors (NOx and VOC) would also contribute to existing violations of these standards. The direct impacts of $NO_{2,}$ in conjunction with worst-case background conditions, would not create a new violation of the 1-hour or annual NO_2 ambient air quality standard. The direct impacts of CO and SO_2 would not be significant because construction of the project would neither cause nor contribute to a violation of these standards. Mitigation for construction emissions of PM10, PM2.5, SOx, NOx, and VOC would be appropriate for reducing impacts to PM10, PM2.5, NO_2, and ozone.

Construction Mitigation

The applicant proposes to reduce construction-related emissions of particulate matter, particulate matter precursors, and ozone precursors by implementing measures consistent with local air district recommendations, soil erosion control requirements, and nuisance prohibitions (AFC Section 5.1.3.8). Emissions mitigation and/or control techniques proposed by the applicant for reducing engine emissions during construction of LEC include:

- Operational measures, such as limiting time spent with the engine idling by shutting down equipment when not in use;
- Regular preventive maintenance to prevent emission increases due to engine problems;
- Use of low sulfur and low aromatic fuel meeting California standards for motor vehicle diesel fuel; and
- Use of low-emitting gas and diesel engines meeting state and federal emissions standards for construction equipment, including, but not limited to, catalytic converter systems and diesel particulate filter systems.

The applicant-proposed control strategies for fugitive dust emissions during construction of LEC include:

- Use either water application or chemical dust suppressant application to control dust emissions from onsite unpaved road travel and unpaved parking areas;
- Use vacuum sweeping and/or water flushing of paved road surfaces to remove buildup of loose material to control dust emissions from travel on the paved access road (including adjacent public streets impacted by construction activities) and paved parking areas;

- Cover all trucks hauling soil, sand, and other loose materials or require all trucks to maintain at least two feet of freeboard;
- Limit traffic speeds on all unpaved site areas to 15 mph;
- Install sandbags or other erosion control measures to prevent silt runoff to roadways;
- Replant vegetation in disturbed areas as quickly as possible;
- Use wheel washers or wash off tires of all trucks exiting construction site; and
- Mitigate fugitive dust emissions from wind erosion of areas disturbed from construction activities (including storage piles) by application of either water or chemical dust suppressant.

Staff agrees that the applicant's proposed mitigation would be effective, although staff believes that additional construction mitigation measures could reduce potential impacts even more.

Additional measures recommended by staff would reduce construction-phase impacts to a less than significant level by further reducing construction emissions of particulate matter and combustion contaminants. Staff believes that the short-term and variable nature of construction activities warrants a qualitative approach to mitigation. Construction emissions and the effectiveness of mitigation varies widely depending on variable levels of activity, the specific work taking place, the specific equipment, soil conditions, weather conditions, and other factors, making precise quantification difficult. Despite this variability, there are a number of feasible control measures that can be implemented to significantly reduce construction emissions. The applicant included in its AFC and staff proposes requiring extensive use of heavy diesel-powered construction equipment with ARB-certified low emission diesel engines. In addition, staff proposes that prior to beginning construction the applicant should provide an Air Quality Construction Mitigation Plan (AQCMP) that specifically identifies mitigation measures to be employed by NCPA to limit air quality impacts during construction. Staff includes proposed staff Conditions of Certification **AQ-SC1** through **AQ-SC5** to implement these requirements. These conditions are consistent with both the applicant's proposed mitigation and the conditions of certification adopted in similar prior licensing cases. Compliance with these conditions would substantially eliminate the potential for significant air quality impacts during construction of the LEC project.

Operation Impacts and Mitigation

The following section discusses ambient air quality impacts that were estimated by NCPA and subsequently evaluated by Energy Commission staff. The applicant performed a number of direct impact modeling analyses, including both fumigation modeling and modeling for impacts during commissioning.

Routine Operation Impacts

A refined dispersion modeling analysis was performed to identify off-site criteria pollutant impacts that would occur from routine operational emissions throughout the life of the project. The worst case 1-hour NO_2 (160 lb/hr) and CO (900 lb/hr) impacts reflect startups, and all other impacts reflect the impacts during normal operation. The modeled impacts are extremely conservative, since the maximum impacts are evaluated under a combination of highest allowable emission rates and the most extreme meteorological conditions, which are unlikely to occur simultaneously. The operating profiles are shown in **Air Quality Table 11** to **Air Quality Table 13**. The predicted maximum concentrations of non-reactive pollutants are summarized in **Air Quality Table 16**.

Air Quality Table 16
LEC, Routine Operation Maximum Impacts (µg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
PM10	24 hour	3.7	**104.5**	**108.2**	50	**216**
	Annual	0.6	**33.4**	**34.0**	20	**170**
PM2.5	24 hour	3.7	**81.2**	**84.9**	35	**243**
	Annual	0.6	**14.4**	**15.0**	12	**125**
CO	1 hour	337.3	5,500	5,837.3	23,000	25
	8 hour	110.2	2,640	2,750.2	10,000	28
NO_2	1 hour [a]	28.5	147	175.5	339	52
	Annual	0.6	34	34.6	57	61
SO_2	1 hour	3.8	46.9	50.7	655	8
	24 hour	1.4	18.3	19.7	105	19
	Annual	0.2	5.2	5.4	80	7

Source: AFC Table 5.1-29R (CH2MHILL2009c).
Note: a. The maximum 1-hour NO_2 concentration is based on AERMOD OLM output.

Staff believes that particulate matter emissions from routine operation would cause a significant impact because they will contribute to existing violations of PM10 and PM2.5 ambient air quality standards. Significant secondary impacts would also occur for PM10, PM2.5, and ozone because operational emissions of particulate matter precursors (including SOx) and ozone precursors (NOx and VOC) would also contribute to existing violations of these standards. The direct impacts of NO_2, in conjunction with worst-case background conditions, would not create a new violation of the 1-hour or annual NO_2 ambient air quality standard. The direct impacts of CO and SO_2 would not be significant because routine operation of the project would neither cause nor contribute to a violation of these standards. Mitigation for emissions of PM10, PM2.5, SOx, NOx, and VOC would be appropriate for reducing impacts to PM10, PM2.5, NO_2, and ozone.

Secondary Pollutant Impacts

The project's gaseous emissions of NOx, SOx, VOC, and ammonia are precursor pollutants that can contribute to the formation of secondary pollutants, ozone, PM10, and PM2.5. Gas-to-particulate conversion in ambient air involves complex chemical and physical processes that depend on many factors, including local humidity, pollutant travel time, and the presence of other compounds. Currently, there are no agency-recommended models or procedures for estimating ozone or particulate nitrate or sulfate formation from a single project or source. However, because of the known relationships of NOx and VOC to ozone and of NOx, SOx, and ammonia emissions to secondary PM10 and PM2.5 formation, it can be said that unmitigated emissions of these pollutants would contribute to higher ozone and PM10/PM2.5 levels in the region. Significant impacts of ozone and PM10/PM2.5 precursors would be mitigated with SJVAPCD offsets (**AQ-SC7**).

Ammonia is a particulate precursor but not a criteria pollutant. Reactive with sulfur and nitrogen compounds, ammonia is especially abundant in the San Joaquin Valley from natural sources, agricultural sources, and as a byproduct of tailpipe controls on motor vehicles. Ammonia particulate forms more readily with sulfates than with nitrates, and particulate formation in the San Joaquin Valley has been found to be limited by the availability of SOx and NOx in ambient air, rather than the availability of ammonia (SJVAPCD 2008 PM2.5 Plan). Offsetting SOx and NOx emissions would both avoid significant secondary PM10/PM2.5 impacts and reduce secondary pollutant impacts to a less than significant level.

Energy Commission staff recommends limiting ammonia slip emissions to the extent feasible. After conducting discovery of this issue (Data Request 63, CH2M2009g), and consistent with the previously mentioned ARB guidance on ammonia slip, staff recommends a condition of certification establishing an ammonia slip limit for the combustion turbine at 5 ppmvd (**AQ-SC9**).

Fumigation Impacts

There is the potential that higher short-term concentrations of pollutants may occur during fumigation conditions. Fumigation conditions are generally short-term in nature and only compared to 1-hour standards. The applicant analyzed the air quality impacts for normal emissions under fumigation conditions using the SCREEN3 Model (AFC Table 5.1-27R, CH2M2009c). In the fumigation impact analysis, only impacts from the turbine stack are evaluated. For comparison, the same operating scenario identified in the operational impact analysis is considered for fumigation. The short-term project impacts during fumigation would not exceed the impacts for routine operation shown in **Air Quality Table 16**, above. Therefore, no additional mitigation is required for fumigation impacts.

Commissioning-Phase Impacts

Commissioning impacts would occur over short-terms within the 28 days expected to be needed to complete the commissioning period. The commissioning emissions estimates are based on partial load operations before the emission control systems become operational, as in **Air Quality Table 10**. Impacts due to PM10, PM2.5, and SO_2 during commissioning would occur under similar exhaust conditions as those for startup while in routine operation because these emissions are proportional to fuel use. **Air Quality Table 17** shows that the commissioning-phase impacts of CO and NO_2 would be somewhat higher than those during routine operations. Commissioning-phase impacts to particulate matter and ozone concentrations would be addressed with the mitigation identified above for routine operations.

Air Quality Table 17
LEC, Commissioning-Phase Maximum Impacts (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
CO	1 hour	748.6	5,500	6,248.6	23,000	27
	8 hour	526.2	2,640	3,166.2	10,000	32
NO_2	1 hour [a]	47.8	147	194.8	339	57

Source: AFC Table 5.1-30 R (CH2MHILL2009c).
Note: a. The maximum 1-hour NO_2 concentration is based on AERMOD OLM output.

Visibility Impacts

A visibility analysis of the project's gaseous emissions would not be required because the LEC project would not qualify as a new major stationary source under the federal Prevention of Significant Deterioration (PSD) permitting program. For projects subject to PSD review by the U.S. EPA, a visibility analysis would address the nearest federally-protected Class I area. The nearest Class I areas are as follows (NCPA2008a):

- Mokelumne Wilderness 106 kilometers (km)
- Emigrant Wilderness 120 km
- Desolation Wilderness 122 km
- Yosemite National Park 124 km
- Point Reyes National Seashore 127 km

Due to its distance from Class I areas being over 100 kilometers, and due to the potential emissions of the project being less than the PSD applicability thresholds, Energy Commission staff anticipates that the project's impacts to visibility would be insignificant.

Mitigation for Routine Operation

Applicant's Proposed Mitigation

The LEC project includes a combination of clean-fuel-firing equipment, emission control devices, and emission reduction credits to mitigate air quality impacts. The equipment description, equipment operation, and emission control devices are provided in **AIR QUALITY PROJECT DESCRIPTION**.

Emission Controls

The proposed combustion turbine would limit NOx formed during combustion using dry low-NOx (DLN) combustors. Compared to steam or water-injection designs, combustors designed for low-NOx firing maintain low temperatures, thus minimizing NOx formation, while thermal efficiencies remain high. To further reduce the emissions from the combustion turbine before they are exhausted into the atmosphere, flue gas controls, primarily catalyst systems, will be installed in the HRSG. NCPA proposes two catalyst systems: the SCR system to reduce NOx; and the oxidation catalyst system to reduce CO and VOC. Operating exclusively on pipeline quality natural gas limits SOx and particulate matter emissions. Additionally, the auxiliary boiler would include ultra low-NOx burners to achieve the District's limits. The proposed project would also achieve additional reduction in emissions by sharing facilities such as the fire protection system with the existing STIG.

Emission Offsets

In addition to emission control strategies included in the project design, SJVAPCD Rule 2201 requires LEC to provide emission reduction credits to offset the new emissions of NOx, VOC, PM10, and SOx. **Air Quality Table 18** summarizes the SJVAPCD Rule 2201 offset requirements for the LEC project, with offsets assumed to originate from shutdowns at sources located more than 15 miles away (distance offset ratio of 1.5-to-1). The SJVAPCD conducted a case-by-case analysis of requirements and distance ratios depending on the specific ERCs held by the applicant (SJVAPCD 2010a).

Air Quality Table 18
LEC, SJVAPCD Offset Determination and Requirements (lb/yr)

Source, as Allowed by SJVAPCD	**NOx**	**VOC**	**PM10**	**CO**	**SOx**
CTG/HRSG	151,415	33,003	78,840	192,650	53,436
Auxiliary Boiler	1,240	616	1,108	5,350	416
Cooling Tower	0	0	8,176	0	0
LEC Potential to Emit	**152,655**	**33,619**	**88,124**	**198,000**	**53,852**
Offset Requirements					
Existing NCPA STIG Potential Emissions	40,977	51,837	17,524	117,553	11,571
SJVAPCD Offset Threshold	20,000	20,000	29,200	200,000	54,750
Offsets Required by SJVAPCD for LEC [a, b]	152,655	33,619	76,448	---	10,673
Offsets Required by SJVAPCD at LEC [c]	**228,983**	**50,429**	**114,672**	**---**	**16,010**

Source: Independent staff assessment and SJVAPCD Final Determination of Compliance (SJVAPCD2010a).

Note:
a. Emission offsets are not required for CO if the applicant demonstrates to the satisfaction of the Air Pollution Control Officer (APCO) that the ambient air quality standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of the standards.
b. SJVAPCD's offsetting rules exempt sources that have potential emissions below the offset threshold, allowing a credit for PM10 and SOx from the existing STIG in this case. This reduces the amount of offsets required for PM10 and SOx caused by LEC.
c. Includes a distance ratio factor of 1.5 for ERCs that would originate from sources over 15 miles away.

The proposed LEC project would be required to surrender offsets according to a quarterly and annual operating profile developed and proposed by the applicant (AFC Table 5.1-15R, CH2M2009c). The applicant's operating profile assumes that startups are not distributed evenly throughout the year, and that during Q3 and Q4, fewer starts would be needed than in Q1 and Q2. The facility is limited in its operation in terms of its quarterly and annual emissions (Conditions of Certification **AQ-35** to **AQ-41**) and emissions during startups (**AQ-25**), rather than its heat input rate or other direct operating limits.

Emission Offsets for Ozone Impact

Air Quality Table 19 summarizes NOx and VOC offset requirements and identifies the sources of offsets proposed by NCPA. The applicant holds numerous NOx and VOC ERCs that it intends to use to satisfy the District offset requirements. Both NOx and VOC emissions are recognized precursors to the formation of ambient ozone, and NOx is also a recognized precursor to the formation of the nitrate fraction of fine particulate matter.

Air Quality Table 19
LEC, NOx and VOC Offset Holdings and Quarterly Offset Requirements (lb/qtr)

Name of Offset / Site of Reduction	ERC Number	Q1 (lb/qtr)	Q2 (lb/qtr)	Q3 (lb/qtr)	Q4 (lb/qtr)
NOx Offsets Held by NCPA					
Bakersfield	S-2857-2	0	0	0	1,031
HOW, Kern County	S-2848-2	1,457	0	1,145	2,959
HOW, Kern County	S-2849-2	2,682	3,241	938	687
HOW, Kern County	S-2850-2	23,349	23,151	24,224	24,469
HOW, Kern County	S-2851-2	1,019	2,105	1,303	264
HOW, Kern County	S-2852-2	2,296	7,000	9,353	954
HOW, Kern County	S-2854-2	0	1,437	0	0
HOW, Kern County	S-2855-2	400	79	4,227	12,090
Hanford	C-915-2	129	137	122	117
Hanford	C-916-2	8,966	1,122	303	0
Fresno	C-914-2	4,702	6,728	3,983	1,831
4000 Yosemite Blvd, Modesto	N-755-2	0	0	27,616	0
202 N Filbert, Stockton	N-754-2	321	274	790	147
Tupman	S-2894-2	9,367	22,816	6,006	26,405
HOW, Kern County	S-2895-2	0	0	0	3,406
NOx Mitigation Total	---	**54,688**	**68,090**	**80,010**	**74,360**
Quarterly NOx Emissions	---	**38,348**	**38,721**	**37,436**	**38,150**
NOx Fully Offset?	---	Yes	Yes	Yes	Yes
VOC Offsets Held by NCPA					
Bakersfield	S-2860-1	12,600	12,600	12,600	12,600
Surplus NOx ERCs (to offset VOC)	(above)	16,340	29,369	42,574	36,210
VOC Mitigation Total	---	**28,940**	**41,969**	**55,174**	**48,810**
Quarterly VOC Emissions	---	**8,240**	**8,331**	**8,571**	**8,477**
VOC Fully Offset?	---	Yes	Yes	Yes	Yes

Source: Quarterly Emissions do not total the LEC Potential to Emit because of differences in the applicant's quarterly operating profile (CH2M2009c) and the annual operating profile (NCPA2009b).
Note: The Name of Offset / Location shows the ERC owner or the location of the reduction in terms of the three SJVAPCD regions. Former ERC owner HOW means Heavy Oil Western.

NCPA appears to be in compliance with the District's NOx and VOC offset requirements and would provide overall total ERCs for ozone precursors at an offset ratio of greater than one-to-one, which satisfies the CEQA mitigation requirements for ozone impacts as established by Energy Commission staff.

Emission Offsets for Particulate Matter Impact

Air Quality Table 20 summarizes PM10 and SOx offset requirements and identifies the sources of PM10 and SOx offsets proposed by NCPA. These offsets are held by NCPA and are being offered as mitigation for the PM10/PM2.5 impacts. NCPA proposes to use its holdings of PM10 and SOx ERCs through an interpollutant trade to satisfy the District offset requirements for PM10.

AIR QUALITY Table 20
LEC, PM10 and SOx Offset Holdings and Quarterly Offset Requirements (lb/qtr)

Name of Offset / Site of Reduction	ERC Number	Q1 (lb/qtr)	Q2 (lb/qtr)	Q3 (lb/qtr)	Q4 (lb/qtr)
PM10 Offsets Held by NCPA					
Shutdown of feedmill, Tulare	S-2844-4	5,830	5,830	4,500	9,830
Shutdown of Cotton Gin, Raisin City	C-911-4	0	0	0	4,244
3200 E Eight Mile Road, Stockton	N-756-4	81	78	583	58
Shutdown of boilers, Auberry, Fresno County	C-913-4	10	45	0	28
Shutdown of oil fired boilers, North Fork, Madera County	C-912-4	60	0	8	5
Surplus SOx ERCs (to offset PM10)	(below)	18,047	16,367	43,672	18,062
PM10 Mitigation Total	---	**24,029**	**22,321**	**48,764**	**32,228**
Quarterly PM10 Emissions	---	**21,761**	**21,977**	**22,193**	**22,193**
PM10 Fully Offset?	---	Yes	Yes	Yes	Yes
SOx Offsets Held by NCPA					
Tulare	S-2843-5	13,298	10,631	12,619	13,452
Tulare	S-2845-5	7,998	9,131	7,319	8,152
Bakersfield	S-2858-5	9,100	9,100	9,080	9,100
4000 Yosemite Blvd, Modesto	N-759-5	0	0	12,651	0
Merced	N-758-5	0	0	11,045	0
Bakersfield	S-2846-5	931	931	931	931
Merced	N-757-5	0	0	3,600	0
SOx Mitigation Total	---	**31,327**	**29,793**	**57,245**	**31,635**
Quarterly SOx Emissions	---	**13,280**	**13,426**	**13,573**	**13,573**
SOx Fully Offset?	---	Yes	Yes	Yes	Yes

Source: Quarterly Emissions do not total the LEC Potential to Emit because of differences in the applicant's quarterly operating profile (CH2M2009c) and the annual operating profile (NCPA2009b).

The applicant proposes to use reductions of SOx to offset PM10/PM2.5 increases associated with the project. The District allows this by establishing an interpollutant offset ratio (District Rule 2201, Section 4.13.3). SOx is accepted as one of the major precursors of PM10 and PM2.5 through reaction with ammonia to form ammonium sulfates. Reductions in SOx, particularly in areas that are ammonia rich such as the San Joaquin Valley, can reduce secondary particulate formation. However, the key issue is the determining the appropriate interpollutant offset ratio, which depends on the existing levels of particulate matter precursors and the general atmospheric chemistry of the area in question. The SJVAPCD conducted a district-wide analysis in March 2009 (Attachment G of SJVAPCD2010a), and the district-wide analysis concluded that a one-to-one interpollutant ratio would be protective of managing regional PM10/PM2.5 impacts and progress towards attainment. However, the District's use of a one-to-one interpollutant ratio for Rule 2201 compliance leads to fewer SOx reductions for particulate matter than ratios used by SJVAPCD in some past cases. This issue is discussed further in **AIR QUALITY CUMULATIVE IMPACTS**.

LEC appears to be in compliance with the District's PM10 and SOx offset requirements and, due to the distance ratio of 1.5, LEC would provide PM10/PM2.5 precursor ERCs at an offset ratio of greater than one-to-one for the emissions over the SJVAPCD offset threshold.

Adequacy of Proposed Mitigation

Energy Commission staff have long held that emission reductions need to be provided for all nonattainment pollutants and their precursors at a minimum overall one-to-one ratio of annual operating emissions. For this project, a staff-recommended Condition of Certification (**AQ-SC7**) and the District's offset requirements ensure that LEC would meet or exceed that minimum offsetting goal for all ozone and particulate matter impacts.

The offsets shown in **Air Quality Table 19** and **Table 20** demonstrate that NCPA owns ERCs in sufficient quantities to offset the project's NOx, VOC, PM10, and SOx emissions, per District requirements and Energy Commission staff policy. Although PM2.5 emissions are not required to be offset separately from PM10 emissions, staff notes that the annual total offsets for PM10 and SOx would fully offset PM2.5 emissions (Response to DR62, CH2MHILL2009g). How the offsets provide PM2.5 mitigation is discussed separately in **AIR QUALITY SECONDARY POLLUTANT IMPACTS**.

While the District has proposed a one-to-one interpollutant offset ratio for SOx and PM10 that is lower than what has been historically required by the District on other cases, Energy Commission staff's long-standing position is that all nonattainment pollutant and precursor emissions must be offset by at least one-to-one. Therefore, the proposed emission offset package would mitigate all project air quality impacts to a less than significant level.

Staff's review of the offset package was determined solely based on the merits of this case, including the District offset requirements, the project's emission limits, the specific ERCs proposed, and ambient air quality considerations of the region, and does not in any way provide a precedence or obligation for the acceptance of offset proposals for any other current or future licensing cases.

Staff Proposed Mitigation

Staff proposes Conditions of Certification **AQ-SC6** to ensure that the license is amended as necessary to incorporate future changes to the air quality permits and to ensure ongoing compliance during commissioning and routine operation through quarterly reports (**AQ-SC8**). Staff also proposes a Condition of Certification (**AQ-SC7**) to ensure that significant impacts of ozone and PM10/PM2.5 precursors would be mitigated with SJVAPCD offsets.

Cumulative Impacts and Mitigation

"Cumulative impacts" are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts" (CEQA Guidelines, §15355). Such impacts can be relatively minor and incremental yet still be significant because of the existing environmental background, particularly when considering other closely related past, present, and reasonably foreseeable future projects.

Criteria pollutants have impacts that are usually (though not always) cumulative by their nature. Rarely will a project itself cause a violation of a federal or state criteria pollutant standard. However, many new sources contribute to violations of criteria pollutant standards because of elevated background conditions. Air districts attempt to reduce background criteria pollutant levels by adopting attainment plans, which are multi-faceted programmatic approaches to attainment. Attainment plans typically include new source review requirements that provide offsets and use Best Available Control Technology, combined with more stringent emissions controls on existing sources.

The discussion of cumulative air quality impacts includes the following three 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" direct emissions locally when combined with other local major emission sources; and
- A discussion of greenhouse gas emissions and global climate change impacts (in **AIR QUALITY APPENDIX AIR-1**).

Summary of Projections

The federal and California Clean Air Acts direct local air quality management agencies to implement plans and programs that lead to attainment and maintenance of the ambient air quality standards. The New Source Review program administered by SJVAPCD and other programs for reducing emissions from mobile sources or area-wide sources are part of air quality management plans.

Ozone

- The **2004 Extreme Ozone Attainment Demonstration Plan** illustrates how the SJVAPCD would attain the federal 1-hour ozone standard that was revoked in 2005. This plan includes elements that are the foundation for later ozone plans.

- The **2007 Ozone Plan** to attain the federal 8-hour ozone standard was approved by ARB on June 14, 2007. This plan would reduce ozone and particulate matter levels in the region, primarily by achieving a 75% reduction in NOx emissions by 2023. Achieving such dramatic reductions would affect all sectors of the region's economy (SJVAPCD 2007). The plan relies on four main approaches: tighter district regulations for stationary sources, wider use of incentive-based measures (like the Carl Moyer Program) to accelerate deployment of cleaner sources, new "innovative" programs for trip-reduction and energy conservation, and expanded controls on mobile source tailpipe emissions.

The proposed LEC project is subject to the current SJVAPCD rules and regulations that specify performance standards, offset requirements, and emission control requirements for stationary sources. The regulations also include requirements for obtaining Authority to Construct (ATC) permits and subsequent operating permits. These regulations apply to LEC and all other projects with emission sources. In general, triennial updates of the attainment plans ensure that population, employment, and transportation trends in the region are taken into account, and compliance with SJVAPCD rules and regulations ensures consistency with the regional air quality management plans. The SJVAPCD made a determination of how the project would comply with the offset requirements and other District rules, and that the LEC project would comply with recently adopted plans and the changing regulatory environment (SJVAPCD2010a). Because the project would control ozone precursor emissions and use ERCs to fully offset ozone precursors as required by existing rules and regulations, the project would not be likely to conflict with the District's 2007 Ozone Plan or regional ozone attainment goals.

Particulate Matter

- The **2007 PM10 Maintenance Plan** illustrates how the SJVAPCD intends to continue the efforts of the **2003 PM10 Plan** and **2006 PM10 Plan** that implemented aggressive PM10 controls in the region, including Reasonably Available Control Measures (RACM) for large existing sources of PM10 and fugitive dust. The 2007 PM10 Maintenance Plan includes a request for reclassification to "attainment" for the federal PM10 standard, and it provides for continued attainment for 10 year from the designation. In November 2008, the U.S. EPA redesignated the SJVAPCD to attainment for the federal PM10 standard (73 FR 66759, November 12, 2008).
- The **2008 PM2.5 Plan** was adopted by the SJVAPCD Governing Board on April 30, 2008, and it includes measures for attaining the 1997 and 2006 federal PM2.5 standards. The 2008 PM2.5 Plan shows that emission reductions of NOx, directly emitted PM2.5, and SO_2 are needed to demonstrate attainment of the PM2.5 NAAQS in the San Joaquin Valley (p. 6-1 of plan).

Energy Commission staff is concerned that the proposed LEC project could interfere with the attainment effort of the 2008 PM2.5 Plan if it relies on SOx emission reduction credits without an adequate trading ratio for allowing PM2.5 increases. Interpollutant trading is allowed with "the appropriate scientific demonstration of an adequate trading ratio" (Rule 2201, Section 4.13), and the SJVAPCD 2007 PM10 Maintenance Plan (see Appendix E of the Maintenance Plan) indicates that the minimum ratio would be one-to-one with higher interpollutant ratios if appropriate under Rule 2201. The one-to-one ratio was developed by the SJVAPCD based on modeling conducted in support of the 2008

PM2.5 Plan, but although implementation of trading under District Rule 2201 is subject to federal oversight, there is no evidence in the record indicating whether the methods used by the District in developing the ratio have been specifically reviewed and/or approved by U.S. Environmental Protection Agency (CEC 2009, USEPA 2009).

The U.S. EPA review of the District's 2008 PM2.5 Plan is ongoing, and the review may lead to a different conclusion on an appropriate interpollutant trading ratio for the SJVAPCD. In rules issued by the U.S. EPA in 2008 related to PM2.5 NSR, the U.S. EPA's "nationwide preferred ratio" would be 40-to-1 for SO2-to-PM2.5 (73 FR 28339; May 16, 2008). Those rules are currently subject to a reconsideration established by U.S. EPA on April 24, 2009, so the ultimate outcome is uncertain. Although there is no formal federal endorsement of the District's interpollutant trading approach, Energy Commission staff is able to conclude that the LEC project would not be likely to conflict with regional particulate matter attainment goals. Staff recognizes that the attainment plan has been previously adopted by ARB, and the SJVAPCD made a determination that the interpollutant trading ratio is appropriate (SJVAPCD2010a). The SJVAPCD shows that LEC is likely to comply with the particulate matter plans by meeting its permit requirements and complying with the existing applicable rules and regulations.

Localized Cumulative Impacts

The proposed project and other reasonably foreseeable projects could cause impacts that would be locally combined if present and future projects would introduce stationary sources that are not included in the "background" conditions. Reasonably foreseeable future projects are those that are either currently under construction or in the process of being approved by a local air district or municipality. Projects that have not yet entered the approval process do not normally qualify as "foreseeable" since the detailed information needed to conduct this analysis is not available. Sources that are presently operational are included in the background concentrations. Background conditions also take into account the effects of non-stationary sources.

Projects with stationary sources located up to six miles from the proposed project site usually need to be considered by the analysis. NCPA requested that the SJVAPCD identify potential new stationary sources within six miles of the Lodi Energy Center. The SJVAPCD reported two facilities with pending foreseeable changes, potentially involving emissions increases of more than 10 pounds per day of a contaminant other than VOC. Although cumulative sources emitting exclusively VOC would contribute to the project-related impacts to secondary ozone formation, these impacts are not modeled in this Staff Assessment because there are no agency-recommended models or procedures for quantifying the cumulative ozone impacts.

In May 2009, Energy Commission staff requested that SJVAPCD update its survey of the foreseeable projects, and six facilities were identified. However, only three projects would involve modifications resulting in potentially increased emissions of more than 10 pounds per day of any contaminant other than VOC. The NCPA cumulative analysis considers the existing NCPA STIG (AFC Appendix 5.1G, CH2M2009c), and the SJVAPCD response to staff on foreseeable sources identified the following facilities and stationary sources:

- **Existing NCPA STIG.** The existing STIG, adjacent to the proposed LEC, would not experience any foreseeable change as a result of the LEC (Response to DR60, CH2M2009g), nor is any change to the existing STIG proposed. The existing stationary sources related to the STIG are included in NCPA's analysis of cumulative impacts, results shown in **Air Quality Table 21**.
- **Facility #N-19.** Proposed natural gas-fired boiler (9900 Lower Sacramento Road, Stockton) would be minor and exempt from permitting requirements and would not involve more than 10 pounds per day of nonattainment pollutants or precursors. This source is not included in the cumulative analysis because it would result in exempt emissions of CO that would not be likely to cause or contribute to nonattainment.
- **Facility #N-5695.** Proposed dairy digester gas-fired internal combustion engine (401 W. Armstrong Road, Lodi). This source is not included in the cumulative analysis because it would replace two existing engines at the facility, resulting in no net emission increase.
- **Facility #N-7763.** Proposed diesel-fueled emergency standby internal combustion engine (8407 Kelley Drive, Stockton). This source is not included in the cumulative analysis because it would only operate intermittently, under emergency conditions, and fewer than 50 hours per year for testing purposes.

The maximum modeled cumulative impacts are presented below in **Air Quality Table 21**. The total impact is conservatively estimated by the maximum modeled impact plus existing maximum background pollutant levels.

Air Quality Table 21
LEC, Ambient Air Quality Impacts from Cumulative Sources (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
PM10	24 hour	9.1	**104.5**	**113.6**	50	**227**
	Annual	0.6	**33.4**	**34.0**	20	**170**
PM2.5	24 hour	9.1	**81.2**	**90.3**	35	**258**
	Annual	0.6	**14.4**	**15.0**	12	**125**
CO	1 hour	340	5,500	5,840	23,000	25
	8 hour	112	2,640	2,752	10,000	28
NO_2	1 hour [a]	144.2	147	291.2	339	86
	Annual	0.7	34	34.7	57	61
SO_2	1 hour	3.9	46.9	50.8	655	8
	24 hour	1.5	18.3	19.8	105	19
	Annual	0.2	5.2	5.4	80	7

Source: AFC Appendix 5.1G, Table 5.1G-4R (CH2M2009c). Short-term impacts include existing NCPA STIG fire pump engine testing. Modeled impact without fire pump engine testing is under 6.0 μg/m^3 for PM10 24-hour.
Notes: a. The maximum 1-hour NO_2 concentration is based on AERMOD OLM output.

Compared with the impacts from the proposed LEC project alone, maximum cumulative impacts caused by the existing NCPA STIG would be substantially higher for PM10/PM2.5 and for NO_2. The combined PM10/PM2.5 and NO_2 impacts caused by LEC and the existing NCPA STIG would be dominated by STIG due to the lower release heights of the existing STIG and fire pump engine stacks.

Staff believes that particulate matter emissions from LEC would be cumulatively considerable because they would contribute to existing violations of the PM10 and PM2.5 ambient air quality standards. Secondary impacts would also be cumulatively considerable for PM10, PM2.5, and ozone because emissions of particulate matter precursors (including SOx) and ozone precursors (NOx and VOC) would contribute to existing violations of the PM10, PM2.5, and ozone standards. To address the contribution caused by LEC to cumulative particulate matter and ozone impacts, the mitigation would offset all nonattainment pollutants and their precursors at a minimum ratio of one-to-one.

COMPLIANCE WITH LORS

The SJVAPCD released a Final Determination of Compliance (FDOC) for LEC in draft form on November 19, 2009 (SJVAPCD2009b) and in final form on January 22, 2010 (SJVAPCD2010a). Compliance with all District Rules and Regulations was demonstrated to the District's satisfaction with conditions that are presented in the Conditions of Certification of this staff assessment. Energy Commission staff and the U.S. EPA provided comments on the initial PDOC to the District for their consideration (CEC 2009, USEPA 2009) and on the draft FDOC (CEC 2009b). Staff accepts the responses made by the District and attached with the FDOC.

FEDERAL

The Determination of Compliance would represent the federal New Source Review (NSR) permit.

40 CFR 52.21, Prevention of Significant Deterioration

The applicant has withdrawn its application to the U.S. EPA for a Prevention of Significant Deterioration (PSD) permit (NCPA2009b). The PSD program would not apply, as long as the LEC project is subject to federally-enforceable operating limitations, which would need to originate in the District's Determination of Compliance. The District released Final Determination of Compliance for the Siemens equipment that establishes limits to avoid applicability of PSD (SJVAPCD2010a). To ensure that LEC amends the Energy Commission license as necessary to incorporate changes triggered by District or U.S. EPA action related to PSD, if any, staff proposes Condition of Certification **AQ-SC6**.

40 CFR 60, NSPS Subpart KKKK

The CTG and HRSG proposed for LEC would be likely to comply with the applicable emission limits by achieving a NOx emission rate of 2.0 ppmvd over any one-hour period except during startup and shutdown periods and during combustor tuning, although periods of tuning would only be allowed during commissioning (SJVAPCD2010a).

STATE

LEC has demonstrated 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. Compliance with the District's and the Energy Commission staff's Conditions of Certification would enable staff's affirmative finding.

LOCAL

The District issued a PDOC for the originally-proposed General Electric combustion turbine (SJVAPCD2009a). Later in 2009, the District provided an updated "draft" Final Determination of Compliance for the Siemens CTG (SJVAPCD2009b). This was followed by the FDOC dated January 22, 2010 (SJVAPCD2010a). The proposed project is expected to comply with all applicable District rules and regulations. This version of the Staff Assessment shows the conditions recommended by the District in its Final Determination of Compliance of January 2010.

The District rules and regulations specify the emissions control and offset requirements for the new sources associated with the Lodi Energy Center. The SJVAPCD determined that the project would use the Best Available Control Technology (BACT), and the emission reduction credits (ERCs) approved and certified by the District would fully offset project nonattainment pollutant (including precursors) emissions so that they would be consistent with District rules and regulations.

Staff and U.S. EPA identified concerns on whether the ERCs would be exchanged with an interpollutant ratio that is consistent with U.S. EPA recommendations (USEPA 2009), as discussed under **AIR QUALITY CUMULATIVE IMPACTS**. The other issues that were identified by staff upon review of the initial PDOC are summarized below (CEC 2009).

Rule 2201, New Source Review and BACT

Staff recommended that the District provide more information in its analysis of Best Available Control Technologies (BACT, on PDOC pp. 26-28) to include information on minimizing startup emissions or startup durations. Energy Commission staff recognizes that the proposed combustion turbine for the Lodi Energy Center would use a rapid startup technology to minimize startup emissions and durations, but at the time of the PDOC, there was no information on whether the District would consider this as a suitable “control technology” for startups. The FDOC addresses this concern by requiring the applicant and District to establish startup time limits for the new Siemens CTG after demonstrating what is achieved in practice.

Staff also recommended that the District consider the Final Determination of Compliance that was issued for the Avenal Power Center on October 30, 2008 (08-AFC-01, Project No. C-1080386) and that the BACT determination be revised for CO from the CTG and HRSG to be limited to no more than 2.0 parts per million (ppm) on a 3-hour basis (Attachment F-5 of the Avenal FDOC). The applicant subsequently filed information indicating that LEC would achieve 2.0 ppm CO (NCPA2009b).

SJVAPCD Rule 4703, Stationary Gas Turbines

Staff raised a number of concerns regarding the preliminary compliance determination for District Rule 4703 (PDOC pp. 73 to 81). The District claims that vendor information indicates startups would potentially exceed the two-hour limit in District Rule 4703, Section 5.3.1.1, but no vendor information on startups was provided to the Energy Commission by NCPA. Projects similar to LEC would meet much more stringent startup limitations than the six hours originally proposed by LEC. No more than 110 minutes would be allowed for startup of the Victorville 2 Hybrid Power Project (07-AFC-1, Final Commission Decision, July 2008, CEC-800-2008-003-CMF) and the Palmdale Hybrid Power Plant (08-AFC-9, currently under review). The applicant subsequently updated its proposal to keep startups under three hours (NCPA2009b), but this would still be over the duration specified by Rule 4703. Staff recommends incorporating conditions established by the District requiring reassessment of LEC startup capabilities after 12 months of normal operation (**AQ-18** and **AQ-19**).

Additionally, it is not clear whether combustor tuning periods (Response to DR64, CH2M2009g) would be compliant with emission limits in Rule 4703 or the federal New Source Performance Standard (40 CFR 60, NSPS Subpart KKKK). Combustor tuning periods described above were requested by NCPA part-way through the SJVAPCD’s review process, but this mode of operation would not be allowed as part of the District conditions except during commissioning.

RESPONSE TO APPLICANT COMMENTS

Testimony filed by the applicant December 22, 2009 objects to proposed condition **AQ-SC9**, regarding ammonia slip, but staff recommends retaining condition because it delineates a feasible operating procedure that avoids unnecessarily high levels of ammonia emissions. Simply put, ammonia *is* a particulate matter precursor. While the need to manage ammonia may be disputed, staff recommends that all power plants mitigate all precursor emissions. This includes limiting ammonia emissions to the extent feasible.

Staff's methodology (**Method and Threshold for Determining Significance**) includes seeking mitigation for *all* precursors to nonattainment pollutants. This basis for **AQ-SC9** has been unchanged in recent years, and it reflects our understanding of all recent San Joaquin Valley air quality management plans. The Energy Commission decision made on December 16, 2009 approving the Avenal Energy Project (08-AFC-1), which would be in the same air basin, and most other recent decisions since the Palomar Energy Project in 2003 include a Condition of Certification similar or identical to **AQ-SC9**.

Compliance with **AQ-SC9** is feasible. Staff's proposed condition allows 12 months to lapse with emissions averaging between 5 ppm and 10 ppm before requiring catalyst improvements. When in frequent use, catalyst degradation would occur quickly within a matter of months. As such, **AQ-SC9** should not cause excessive catalyst replacements or waste catalyst material. Furthermore, minimizing unnecessary ammonia emissions reduces NCPA's costs for ammonia supplies.

CONCLUSIONS

- Construction impacts would contribute to violations of the ozone, PM10, and PM2.5 ambient air quality standards. Staff recommends Conditions of Certification **AQ-SC1** to **AQ-SC5** to mitigate the project construction-phase impacts to a less than significant level.
- Staff has determined that operation of the Lodi Energy Center project would be likely to comply with applicable SJVAPCD rules and regulations, including New Source Review, Best Available Control Technology (BACT) requirements, performance standards for stationary gas turbines in startup modes, and requirements to offset emission increases. In order to determine conformance with applicable federal, state, and SJVAPCD LORS, staff relies on the results of the SJVAPCD review of the Siemens CTG that the applicant proposed in July 2009. This Staff Assessment reflects the SJVAPCD's Final Determination of Compliance, released in January 2010.
- The project would neither cause new violations of any NO_2, CO, or SO_2 ambient air quality standards nor contribute to existing violations for these pollutants. Therefore, the project's direct NO_2, CO, and SO_2 impacts are less than significant.
- The project NOx and VOC emissions would contribute to existing violations of state and federal ozone ambient air quality standards. The ozone precursor offsets required by SJVAPCD and shown in Condition of Certification **AQ-SC7** would mitigate the ozone impact to a less than significant level.
- Without proper mitigation, the project PM10 and PM2.5 emissions and the PM10/PM2.5 precursor emissions of SOx would contribute to the existing violations of state and federal PM10 and PM2.5 ambient air quality standards. ERCs would be accepted for PM10 and SOx reductions (**AQ-SC7**), and these ERCs would mitigate

the PM10/PM2.5 impacts to a less than significant level. The particulate matter precursor offsets would satisfy Energy Commission staff's long-standing position that all nonattainment pollutant and precursor emissions be offset at least one-to-one. Future projects may be subject to different offset ratios because the U.S. EPA review of the SJVAPCD's 2008 PM2.5 Plan is ongoing, and there is no evidence that the District's interpollutant trading ratios have been specifically reviewed and/or approved by U.S. EPA (see **AIR QUALITY CUMULATIVE IMPACTS**).

- Staff recommends Condition of Certification **AQ-SC9** to limit ammonia slip from the combined-cycle system to the extent feasible.
- Global climate change and greenhouse gas (GHG) emissions from the project are analyzed in **Air Quality Appendix AIR-1**. The LEC would be able to comply with the requirements of SB 1368 and the Emission Performance Standard. The project would be subject the Air Resources Board mandatory GHG reporting requirements and any GHG reduction or trading requirements developed by the ARB as GHG regulations are implemented.

PROPOSED CONDITIONS OF CERTIFICATION

STAFF-RECOMMENDED CONDITIONS OF CERTIFICATION

Staff proposes the following conditions of certification (identified as the **AQ-SCx** series of conditions) to provide mitigation during the construction phase of the project.

AQ-SC1 <u>Air Quality Construction Mitigation Manager (AQCMM)</u>: The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with conditions **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 construction project manager (CPM).

<u>Verification:</u> At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM delegates. The AQCMM and all delegates must be approved by the CPM before the start of ground disturbance.

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

<u>Verification:</u> At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. The AQCMP must be approved by the CPM before the start of ground disturbance.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each monthly compliance report (MCR) that demonstrates compliance with the following mitigation measures for purposes of preventing all fugitive dust plumes from leaving the project site and linear facility routes. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

A. All unpaved roads and disturbed areas in the project and linear construction sites shall be watered as frequently as necessary to comply with the dust mitigation objectives of **AQ-SC4**. The frequency of watering may be either reduced or eliminated during periods of precipitation.

B. No vehicle shall exceed 15 miles per hour within the construction site.

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

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

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

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

G. 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.

H. Construction areas adjacent to any paved roadway shall be provided with sandbags or other equivalently effective measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent run-off to roadways.

I. 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.

J. At least the first 500 feet of any public roadway exiting from the construction site 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 run-off from the construction site is visible on the public roadways.

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

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

M. 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 project owner shall include in the MCR: (1) a summary of all actions taken to maintain compliance with this condition; (2) copies of any complaints filed with the air district in relation to project construction; and (3) 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-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 with the potential to be transported off the project site, 200 feet beyond the centerline of the construction of linear facilities, or within 100 feet upwind of any regularly occupied structures not owned by the project owner indicate that existing mitigation measures are not providing effective mitigation. The AQCMM or delegate shall then implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed.

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

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

Step 3: The AQCMM or delegate shall direct a temporary shutdown of the activity causing the emissions if Step 2 specified above fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or delegate to shut down an activity, provided that the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMP shall include a section detailing how additional mitigation measures will be accomplished within specified time limits.

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 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 50 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 either a Tier 1 engine or the highest level of available control is being used; or

   2. The construction equipment is intended to be on site for five 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.

   4. Equipment owned by specialty subcontractors may be granted an exemption, for single equipment items on a case-by-case basis, if it can be demonstrated that extreme financial hardship would occur if the specialty subcontractor had to rent replacement equipment, or if it can be demonstrated that a specialized equipment item is not available by rental.

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 the AQCMM demonstrates that one of the following conditions exists:

1. The use of the 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 control device is causing or is reasonably expected to cause significant engine damage.

3. The control device is causing or is reasonably expected to cause a significant 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, to the extent practical.

F. Construction equipment will employ electric motors when feasible.

Verification: The project owner shall include in the MCR: (1) a summary of all actions taken to maintain compliance with this condition; (2) 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 the equipment has been properly maintained; and (3) 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-SC6 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. EPA, and any revised permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any proposed air permit modification to the CPM within five 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-SC7 The project owner shall provide emission reductions in the form of offsets or emission reduction credits (ERCs) in the quantities of at least 152,655 lb NOx, 33,619 lb VOC, 88,124 lb PM10, and 53,852 lb SOx emissions. The project owner shall demonstrate that the reductions are provided in the form required by the District.

The project owner shall surrender the ERCs from among those that are listed in the District Final Determination of Compliance Conditions (SJVAPCD2010a) or a modified list, as allowed by this condition. If additional ERCs are submitted, the project owner shall submit an updated table including the additional ERCs to the CPM. The project owner shall request CPM approval for any substitutions, modifications, or additions to the listed credits.

The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, and that the requested change(s) will not cause the project to result in a significant environmental impact. The District must also confirm that each requested change is consistent with applicable federal and state laws and regulations.

Verification: The project owner shall submit to the CPM records showing that the project's offset requirements have been met prior to initiating construction. If the CPM approves a substitution or modification to the list of ERCs, the CPM shall file a statement of the approval with the project owner and Commission docket. The CPM shall maintain an updated list of approved ERCs for the project.

AQ-SC8 The project owner shall submit to the CPM quarterly operation reports that include operational and emissions information as necessary to demonstrate compliance with the conditions of certification. The quarterly operation report shall specifically note or highlight incidences of noncompliance.

Verification: The project owner shall submit quarterly operation reports to the CPM and APCO no later than 30 days following the end of each calendar quarter. This information shall be maintained on site for a minimum of five years and shall be provided to the CPM and District personnel upon request.

AQ-SC9 The ammonia (NH_3) emissions from the combustion turbine (N-2697-5) shall not exceed 10 ppmvd @ 15% O_2 averaged over a 24 hour rolling average. The selective catalytic reduction (SCR) system catalyst shall be replaced, repaired, or otherwise reconditioned within 12 months if the ammonia slip exceeds 5 ppmvd @ 15% O_2 over a 24 hour rolling average. The SCR ammonia injection grid replacement, repair, or reconditioning scheduled event may be cancelled if the owner or operator can demonstrate that, subsequent to the initial exceedance, the ammonia slip consistently remains below 5 ppmvd @ 15% O_2 averaged over 24 hours, and that the initial exceedance does not accurately indicate expected future operating conditions.

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

DISTRICT CONDITIONS

The SJVACPD released a "draft" Final Determination of Compliance in November 2009 and the Final Determination of Compliance in January 2010 for the proposed Siemens equipment. The following conditions are from the Final Determination of Compliance (SJVAPCD2010a), as follows:

- Combined cycle system combustion turbine (**AQ-1** to **AQ-69**);
- Facility-wide conditions for offsets (**AQ-70** to **AQ-79**);
- Facility-wide conditions for dust control (**AQ-80** to **AQ-89**);
- Facility-wide conditions for Acid Rain program (**AQ-90** to **AQ-103**);
- Cooling tower (**AQ-104** to **AQ-116**); and
- Auxiliary boiler (**AQ-117** to **AQ-159**).

EQUIPMENT DESCRIPTION, UNIT N-2697-5-0

294 MW (NOMINAL) COMBINED-CYCLE ELECTRIC GENERATION PLANT CONSISTING OF A SIEMENS INDUSTRIAL FRAME "FLEX PLANT 30" STG6-5000F NATURAL GAS-FIRED TURBINE ENGINE WITH DRY LOW-NO_X COMBUSTORS, AN UNFIRED HEAT RECOVERY STEAM GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION AND AN OXIDIZATION CATALYST AND A STEAM TURBINE GENERATOR

AQ-1 The permittee shall not begin actual on-site construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-2 This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]

Verification: No verification necessary.

AQ-3 Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

Verification: The project owner shall submit to both the District and CPM the Title V Operating Permit application prior to operation.

AQ-4 The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-5 The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-6 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-7 Particulate matter emissions from the gas turbine system shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Verification: The project owner shall submit the results of source tests to both the District and CPM in accordance with **AQ-46**.

AQ-8 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-9 APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-10 Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the gas turbine and associated electrical delivery systems. [District Rule 2201]

Verification: No verification necessary.

AQ-11 Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial source testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

Verification: The project owner shall submit a commissioning plan to the CPM and APCO for approval at least 30 days prior to first firing of the gas turbine describing the procedures to be followed during the commissioning period and the anticipated duration of each commissioning activity.

AQ-12 During the commissioning period, the emission rates from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) - 400.00 lb/hr and 4,000 lb/day; VOC (as CH4) - 16.00 lb/hr and 192.0 lb/day; CO - 2,000 lb/hr and 20,000 lb/day; PM10 - 9.00 lb/hr and 108.0 lb/day; or SOx (as SO2) - 6.10 lb/hr and 73.1 lb/day. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-13 During commissioning period, NOx and CO emissions rate shall be monitored using installed and calibrated CEMS. [District Rule 2201]

Verification: The project owner shall submit to the CPM and APCO for approval the commissioning plan as required in **AQ-11**.

AQ-14 The total mass emissions of NOx, VOC, CO, PM10 and SOx that are emitted during the commissioning period shall accrue towards the quarterly emission limits. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-15 During commissioning period, the owner or operator shall keep records of the natural gas fuel combusted in the gas turbine system on hourly and daily basis. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-16 The duration of startup or shutdown period shall not exceed 3.0 hours per event for any type of startup event (hot, warm, or cold). [District Rules 2201 and 4703]

Verification: The project owner shall submit to the District and CPM the startup and shutdown event duration data demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-17 The combined startup and shutdown duration for all events shall not exceed 6.0 hours during any one day. [District Rule 2201]

Verification: The project owner shall submit to the District and CPM the startup and shutdown event duration data demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-18 The owner/operator shall maintain records of the date, start-up time, downtime for gas turbine and the steam turbine prior to startup, startup type, minute-by-minute turbine load (MW), and NOx and CO concentrations (ppmvd @ 15% O2) measurement using CEMS, for each startup event in the first 12 months of operation following the end of the commissioning period. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-19 Within 15 months of the end of the commissioning period, the owner/operator shall submit to the District, the CARB and the EPA proposed new time limits for each type of startup that reflect the effect of "Flex Plant 30" fast start-up technology. The proposed time limits shall be based on the required data collected in the first 12 months of operation following the end of the commissioning period. The submittal must include all CEMS data. [District Rule 2201]

Verification: A review of startup time limits and recommendations for new limits shall be provided to the CPM and APCO within 15 months of the end of the commissioning period.

AQ-20 A margin of compliance of 60 minutes (or less) may be added to the longest startup to establish a startup limit for each type of startup event (hot, warm, or cold). The established startup limit shall not exceed 3.0 hours. [District Rule 2201]

Verification: See Verification for **AQ-19**.

AQ-21 The District shall administratively establish appropriate startup times for each startup mode (hot, warm, or cold), and associated recordkeeping requirements. [District Rule 2201]

Verification: See Verification for **AQ-20**.

AQ-22 During all types of operation, including startup (cold, warm and hot) and shutdown periods, ammonia injection into the SCR system shall occur once the minimum temperature at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The minimum catalyst face temperature shall be determined during the final design phase of this project and shall be submitted to the District at least 30 days prior to commencement of construction. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-23 The District shall administratively add the minimum temperature limitation established pursuant to the above condition in the final Permit to Operate. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-24 The SCR system shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the catalyst face. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-25 During start-up and shutdown periods, the emissions shall not exceed any of the following limits: NOx (as NO2) - 160.00 lb/hr; CO - 900.00 lb/hr; VOC (as methane) - 16.00 lb/hr; PM10 - 9.00 lb/hr; SOx (as SO2) - 6.10 lb/hr; or Ammonia (NH3) - 28.76 lb/hr. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-26 Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. [District Rule 4703, 3.29]

Verification: No verification necessary.

AQ-27 Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status ending when the fuel supply to the unit is completely turned off. [District Rule 4703, 3.26]

Verification: No verification necessary.

AQ-28 The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703, 5.3.2]

Verification: The project owner shall submit to the District and CPM the startup and shutdown event duration data demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-29 Except during startup and shutdown periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) - 15.54 lb/hr and 2.0 ppmvd @ 15% O2; CO – 9.46 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.79 lb/hr and 1.4 ppmvd @ 15% O2; PM10 - 9.0 lb/hr; or SOx (as SO2) - 6.10 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-30 NH3 emissions shall not exceed any of the following limits: 10.0 ppmvd @ 15% O2 over a 24-hour rolling average period, and 28.76 lb/hr. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-31 Each 3-hour rolling average period will be compiled from the three most recent one hour periods. Each one hour period shall commence on the hour. Each one hour period in a twenty-four hour rolling average for ammonia slip will commence on the hour. The twenty-four hour rolling average shall be calculated using the most recent twenty-four one-hour periods. [District Rule 2201]

Verification: No verification necessary.

AQ-32 Emissions from the gas turbine system, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) - 879.7 lb/day; CO - 5,570.3 lb/day; VOC - 164.2 lb/day; PM10 - 216.0 lb/day; SOx (as SO2) - 146.4 lb/day, or NH3 - 690.3 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-33 Emissions from the gas turbine system, on days when a startup and/or shutdown does not occur, shall not exceed the following: NOX (as NO2) - 373.0 lb/day; CO - 227.0 lb/day; VOC - 91.0 lb/day; PM10 - 216.0 lb/day; SOX (as SO2) - 146.4 lb/day, or NH3 - 690.3 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-34 Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Verification: The result of the natural gas fuel sulfur monitoring data and other fuel sulfur content source data shall be submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-35 NOx (as NO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 38,038 lb; 2nd quarter: 38,411 lb; 3rd quarter: 37,126 lb; 4th quarter: 37,840 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-36 CO emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 142,312 lb; 2nd quarter: 142,539 lb; 3rd quarter: 86,374 lb; 4th quarter: 113,660 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-37 VOC emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 8,086 lb; 2nd quarter: 8,177 lb; 3rd quarter: 8,417 lb; 4th quarter: 8,323 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-38 NH3 emissions from the SCR system shall not exceed any of the following: 1st quarter: 62,122 lb; 2nd quarter: 62,812 lb; 3rd quarter: 63,502 lb; 4th quarter: 63,502 lb. [District Rule]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-39 PM10 emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 19,440 lb; 2nd quarter: 19,656 lb; 3rd quarter: 19,872 lb; 4th quarter: 19,872 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-40 SOx (as SO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 13,176 lb; 2nd quarter: 13,322 lb; 3rd quarter: 13,469 lb; 4th quarter: 13,469 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-41 The total CO emissions from the gas turbine system (N-2697-5) and the auxiliary boiler (N-2697-7) shall not exceed 198,000 pounds in any 12-consecutive month rolling period. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-42 A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine system. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-43 The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators or equivalent technology sufficient to limit the visible emissions from the lube oil vents to not exceed 5% opacity, except for a period not exceeding three minutes in any one hour. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-44 Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

Verification: The project owner shall submit the proposed source test plan or protocol for the source tests 15 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 30 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-45 Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-46 Source testing to measure startup and shutdown of NOx, CO, and VOC mass emission rates shall be conducted before the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NOX and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081]

Verification: The results and field data collected during source tests shall be submitted to the District and CPM within 60 days of testing and according to a pre-approved protocol (**AQ-44**). Testing for startup and shutdown emissions shall be conducted upon initial operation and at least once every seven years.

AQ-47 Source testing to determine compliance with the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted before the end of commissioning period and at least once every 12 months thereafter. [District Rules 2201 and 4703, 40 CFR 60.4400(a)]

Verification: The results and field data collected during source tests shall be submitted to the District and CPM within 60 days of testing and according to a pre-approved protocol (**AQ-44**). Testing for steady-state emissions shall be conducted upon initial operation and at least once every 12 months.

AQ-48 The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract, or (ii) monitored within 60 days after the end of commissioning period and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Verification: The result of the natural gas fuel sulfur monitoring data and other fuel sulfur content source data shall be submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-49 The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703, 40 CFR 60.4400(1)(i)]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-50 Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Verification: The result of the natural gas fuel sulfur monitoring data and other fuel sulfur content source data shall be submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-51 The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Verification: The project owner shall submit the source test report of results to both the District and CPM within 60 days of the completion of the tests.

AQ-52 A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 4703]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-53 The owner or operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) which continuously measures and records the exhaust gas NOx, CO, and O2 concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB and the Commission to verify the continuous monitoring system is properly installed and operational.

AQ-54 The NOx and O2 CEMS shall be installed and certified in accordance with the requirements of 40 CFR Part 75. The CO CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 4A (PS 4A), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-55 The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-56 The CEMS data shall be reduced to hourly averages as specified in §60.13(h) and in accordance with §60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4350]

Verification: The project owner shall submit to the CPM and APCO CEMS data reduced in compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-57 In accordance with 40 CFR Part 60, Appendix F, 5.1, the CO CEMS must be audited at least once each calendar quarter, by conducting cylinder gas audits (CGA) or relative accuracy audits (RAA). CGA or RAA may be conducted three of four calendar quarters, but no more than three calendar quarters in succession. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-58 The owner or operator shall perform RATA for CO as specified by 40 CFR Part 60, Appendix F, 5.1.1, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-59 The NOx and O2 CEMS shall be audited in accordance with the applicable requirements of 40 CFR Part 75. Linearity reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

Verification: The project owner shall submit to the CPM and APCO CEMS audits demonstrating compliance with this condition as part of the quarterly operation report (**AQ-SC8**).

AQ-60 Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rule 1080]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB and the Commission upon request.

AQ-61 The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis. Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080]

Verification: The project owner shall provide a Continuous Emission Monitoring System (CEM) protocol for approval by the APCO and CPM at least 60 days prior to installation of the CEM. The project owner shall make the site available for inspection by representatives of the District, ARB and the Commission upon request.

AQ-62 The owner or operator shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.7(b)]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-63 The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB and the Commission upon request.

AQ-64 Monitor Downtime is defined as any unit operating hour in which the data for NOx or O2 concentrations is either missing or invalid. [40 CFR 60.4380(b)(2)]

Verification: No verification necessary.

AQ-65 The owner or operator shall maintain records of the following items: 1) hourly and daily emissions, in pounds, for each pollutant listed in this permit on the days startup and or shutdown of the gas turbine system occurs, 2) hourly and daily emissions, in pounds, for each pollutant in this permit on the days startup and or shutdown of the gas turbine system does not occur, 3) quarterly emissions, in pounds, for each pollutant listed in this permit, and 4) the combined CO emissions (12 consecutive month rolling total) in pounds, for permit unit N-2697-5 and N-2697-7. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-66 The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, total hours of operation, the type and quantity of fuel used, mode of start-up (cold, warm, or hot), duration of each start-up, and duration of each shutdown. [District Rule 2201 and 4703, 6.26, 6.28, 6.2.11]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-67 The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 2201 and 4703, 6.2.4]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-68 The owner or operator shall submit a written report of CEM operations for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Date, time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Verification: The project owner shall submit to the District and CPM the report of CEM operations, emission data, and monitor downtime data in the quarterly operation report (**AQ-SC8**) that follows the definitions of this condition.

AQ-69 The owner or operator shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when the CEMS is not operating properly. [District Rule 4703, 6.2.5]

Verification: The project owner shall submit to the District and CPM the report of CEM operations, emission data, and monitor downtime data in the quarterly operation report (**AQ-SC8**).

AQ-70 Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of NOx: 1st quarter: 38,348 lb, 2nd quarter: 38,721 lb, 3rd quarter: 37,436 lb, and 4th quarter: 38,150 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-71 NOx ERCs S-2857-2, S-2848-2, S-2849-2, S-2850-2, S-2851-2, S-2852-2, S-2854-2, S-2855-2, C-915-2, C-916-2, C-914-2, N-755-2, N-754-2, S-2894-2 and S-2895-2 (or a certificate split from any of these certificates) shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-72 Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of VOC: 1st quarter: 8,240 lb, 2nd quarter: 8,331 lb, 3rd quarter: 8,571 lb, and 4th quarter: 8,477 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-73 VOC ERC S-2860-1, and NOx ERCs S-2857-2, S-2848-2, S-2849-2, S-2850-2, S-2851-2, S-2852-2, S-2854-2, S-2855-2, C-915-2, C-916-2, C-914-2, N-755-2, N-754-2, S-2894-2 and S-2895-2 (or a certificate split from any of these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-74 The District has authorized to use NOx reductions to overcome shortfall in the amount of VOC offsets at NOx/VOC interpollutant offset ratio of 1.00. [District Rule 2201]

Verification: No verification necessary.

AQ-75 Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of SOx: 1st quarter: 2,668 lb, 2nd quarter: 2,668 lb, 3rd quarter: 2,668 lb, and 4th quarter: 2,668 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-76 SOx ERCs S-2843-5, S-2845-5, S-2858-5, N-759-5, N-758-5, S-2846-5 and N-757-5 (or a certificate split from any of these certificates) shall be used to supply the required SOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-77 Prior to operating under ATCs N-2697-5-0, N-2697-6-0 and N-2697-7-0, the permittee shall mitigate the following quantities of PM10: 1st quarter: 19,112 lb, 2nd quarter: 19,112 lb, 3rd quarter: 19,112 lb, and 4th quarter: 19,112 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-78 PM10 ERCs S-2844-4, C-911-4, N-756-4, C-913-4, C-912-4, and SOx ERCs S-2843-5, S-2845-5, S-2858-5, N-759-5, N-758-5, S-2846-5 and N-757-5 (or a certificate split from any of these certificates) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

Verification: The project owner shall submit to both the District and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-79 The District has authorized to use SOx reductions to overcome shortfall in the amount of PM10 offsets at SOx/PM10 interpollutant offset ratio of 1.00. [District Rule 2201]

Verification: No verification necessary.

AQ-80 Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

Verification: A summary of significant construction activities and monitoring records required shall be included in the construction monthly compliance report (**AQ-SC3**).

AQ-81 An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or five acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

Verification: The Dust Control Plan shall be included within the Air Quality Construction Mitigation Plan and submitted to the District and CPM (**AQ-SC2**), and a summary of significant construction activities and monitoring records required shall be included in the construction monthly compliance report (**AQ-SC3**).

AQ-82 An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 or Rule 8011. [District Rules 8011 and 8021]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-83 Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-84 Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-85 Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-86 Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-87 On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with three axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-88 Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-89 Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031 and 8071]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-90 The owners and operators of each affected source and each affected unit at the source shall have an Acid Rain permit and operate in compliance with all permit requirements. [40 CFR 72]

Verification: The project owner shall submit to both the District and CPM the Acid Rain Program application after completing commissioning.

AQ-91 The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75. [40 CFR 75]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-92 The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-93 The owners and operators of each source and each affected unit at the source shall: (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-94 Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77]

Verification: No verification necessary.

AQ-95 Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-96 An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-97 An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72]

Verification: No verification necessary.

AQ-98 An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72]

Verification: No verification necessary.

AQ-99 The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77. [40 CFR 77]

Verification: The project owner shall submit to both the District and CPM the proposed offset plan as required by the federal rule.

AQ-100 The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) Pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-101 The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-102 The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 75]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-103 The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75]

Verification: The project owner shall submit to both the District and CPM the Acid Rain Program application after completing commissioning.

EQUIPMENT DESCRIPTION, UNIT N-2697-6-0

69,000 GALLONS PER MINUTE COOLING TOWER WITH SEVEN CELLS SERVED BY HIGH EFFICIENCY DRIFT ELIMINATORS

AQ-104 The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-105 This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]

Verification: No verification necessary.

AQ-106 Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

<u>Verification:</u> The project owner shall submit to both the District and CPM the Title V Operating Permit application prior to operation.

AQ-107 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-108 The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

<u>Verification:</u> A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-109 The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

<u>Verification:</u> A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-110 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-111 Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

<u>Verification:</u> The results of water recirculation rate and total dissolved solids concentration analysis data shall be included in the quarterly operation report (**AQ-SC8**).

AQ-112 No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-113 The drift rate shall not exceed 0.0005%. [District Rule 2201]

<u>Verification:</u> A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-114 PM10 emissions shall not exceed 22.4 pounds per day. [District Rule 2201]

<u>Verification:</u> The results of water recirculation rate and total dissolved solids concentration analysis data shall be included in the quarterly operation report (**AQ-SC8**).

AQ-115 Compliance with the PM10 emission limit (lb/day) shall be demonstrated by using the following equation: Water Recirculation Rate (gal/day) x 8.34 lb/gal x Total Dissolved Solids Concentration in the blowdown water (ppm x 10E-06) x Design Drift Rate (%). [District Rule 2201]

<u>Verification:</u> The results of water recirculation rate and total dissolved solids concentration analysis data shall be included in the quarterly operation report (**AQ-SC8**).

AQ-116 Compliance with PM10 emission limit shall be determined by blowdown water sample analysis by independent laboratory within 60 days after the end of commissioning period of the gas turbine system and at least once quarterly thereafter. [District Rules 2201 and 1081]

<u>Verification:</u> The project owner shall use the results of water recirculation rate and total dissolved solids concentration analysis data to determine emissions (lb/day and grains/dscf) and the results shall be included in the quarterly operation report (**AQ-SC8**).

<u>EQUIPMENT DESCRIPTION, UNIT N-2697-7-0</u>

36.5 MMBTU/HR RENTECH BOILER SYSTEMS INC "D" TYPE BOILER (OR EQUIVALENT) EQUIPPED WITH A TODD/COEN RMB ULTRA LOW-NO_X BURNER (PART OF SIEMENS' "FLEX-PLANT 30" SYSTEM)

AQ-117 The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-118 This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]

<u>Verification:</u> No verification necessary.

AQ-119 Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

Verification: The project owner shall submit to both the District and CPM the Title V Operating Permit application prior to operation.

AQ-120 All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-121 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-122 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-123 Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Verification: The project owner shall submit the results of fuel sulfur content analysis to both the District and CPM in accordance with **AQ-48**.

AQ-124 The unit shall only be fired on PUC-regulated natural gas. [District Rules 2201 and 4320]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-125 A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rule 2201, 40 CFR60.48(c)(g)]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

AQ-126 The total mass emissions of NOx, VOC, CO, PM10 and SOx that are emitted during the commissioning period shall accrue towards the quarterly emission limits. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-127 During commissioning period, the owner or operator shall keep records of the natural gas fuel combusted in the boiler on daily basis. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-128 The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-129 The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-130 NOx (as NO2) emissions shall not exceed 7.0 ppmvd @ 3% O2. [District Rules 2201, 4305, 4306 and 4320]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-131 CO emissions shall not exceed 50 ppmvd @ 3% O2. [District Rules 2201, 4305, 4306 and 4320]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-132 VOC (as CH4) emissions shall not exceed 10.0 ppmvd @ 3% O2. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-133 PM10 emissions shall not exceed 0.0076 lb/MMBtu. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-134 SOx emissions shall not exceed 0.00285 lb/MMBtu. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-135 NOx (as NO2) emissions from this unit shall not exceed any of the following: 1st quarter: 310 lb; 2nd quarter: 310 lb; 3rd quarter: 310 lb; 4th quarter: 310 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-136 CO emissions from this unit shall not exceed any of the following: 1st quarter: 1,348 lb; 2nd quarter: 1,348 lb; 3rd quarter: 1,348 lb; 4th quarter: 1,348 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-137 VOC emissions from this unit shall not exceed any of the following: 1st quarter: 154 lb; 2nd quarter: 154 lb; 3rd quarter: 154 lb; 4th quarter: 154 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-138 PM10 emissions from this unit shall not exceed any of the following: 1st quarter: 277 lb; 2nd quarter: 277 lb; 3rd quarter: 277 lb; 4th quarter: 277 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-139 SOx (as SO2) emissions from this unit shall not exceed any of the following: 1st quarter: 104 lb; 2nd quarter: 104 lb; 3rd quarter: 104 lb; 4th quarter: 104 lb. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-140 The total CO emissions from the gas turbine system (N-2697-5) and the auxiliary boiler (N-2697-7) shall not exceed 198,000 pounds in any 12-consecutive month rolling period. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-141 All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-142 Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted before the end of commissioning period of the gas turbine system. [District Rules 2201, 4305 and 4306]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-143 Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306 and 4320]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**. Testing for steady-state emissions shall be conducted upon initial operation and at least once every 12 months or every 36 months as specified by this condition.

AQ-144 The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-145 Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-146 NOx emissions for source test purposes shall be determined using EPA Method 7E or CARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306 and 4320]

Verification: The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-147 CO emissions for source test purposes shall be determined using EPA Method 10 or CARB Method 100. [District Rules 4305, 4306 and 4320]

<u>Verification:</u> The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-148 Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or CARB Method 100. [District Rules 4305, 4306 and 4320]

<u>Verification:</u> The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-149 For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306 and 4320]

<u>Verification:</u> The project owner shall submit the proposed protocol for the source tests to both the District and CPM for approval in accordance with condition **AQ-44**.

AQ-150 The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

<u>Verification:</u> The project owner shall submit the source test report of results to both the District and CPM within 60 days of completion of the tests.

AQ-151 The owner or operator shall submit an analysis showing the fuel's sulfur content at least once every year. Valid purchase contracts, supplier certifications, tariff sheets, or transportation contacts may be used to satisfy this requirement, provided they establish the fuel's sulfur content. [District Rule 4320]

<u>Verification:</u> The result of the natural gas fuel sulfur monitoring data and other fuel sulfur content source data shall be submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-152 Fuel sulfur content shall be determined using EPA Method 11 or EPA Method 15 or District, CARB and EPA approved alternative methods. [District Rule 4320]

<u>Verification:</u> The result of the natural gas fuel sulfur monitoring data and other fuel sulfur content source data shall be submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-153 The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications given in District Policy SSP-1105. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within five days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306 and 4320]

<u>Verification:</u> The results of the boiler stack emission monitoring data shall be summarized and submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-154 If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than one hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after one hour of operation after detection, the permittee shall notify the District within the following one hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4320]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**). The results of the boiler stack emission monitoring data shall be summarized and submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-155 All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]

Verification: The project owner shall provide a protocol for any alternate monitoring parameters at least 60 days prior to implementing alternate monitoring procedures. The results of the boiler stack emission monitoring data shall be summarized and submitted to the District and CPM in the quarterly operation report (**AQ-SC8**).

AQ-156 The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4320]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-157 The permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rule 2201, 40 CFR 60.48(c)(g)]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-158 The permittee shall maintain records of: (1) the date, (2) heat input rate, MMBtu/day, (3) daily emissions, in pounds for each pollutant listed in this permit, (4) quarterly emissions, in pounds, for each pollutant listed in this permit, and the combined CO emissions (12 consecutive month rolling total) in pounds, for permit unit N-2697-5 and N-2697-7. [District Rule 2201]

Verification: A summary of significant operation and maintenance events and monitoring records required shall be included in the quarterly operation report (**AQ-SC8**).

AQ-159 All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, 4306 and 4320]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, and the Commission upon request.

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AIR QUALITY APPENDIX AIR-1

Greenhouse Gas Emissions

Brewster Birdsall, P.E., QEP and Matthew Layton, P.E.

SUMMARY OF CONCLUSIONS

The Lodi Energy Center (LEC) project is a proposed addition to the state's electricity system. It would be an efficient, new, dispatchable natural gas-fired combined cycle power plant that would produce greenhouse gas (GHG) emissions while generating electricity for California consumers. Its addition to the system would displace other less efficient plants and facilitate the integration of renewable resources. Because the project's emissions per megawatt-hour (MWh) would be lower than those of other power plants that the project would displace, the addition of Lodi Energy Center would contribute to a reduction of the California and overall Western Electricity Coordinating Council system GHG[1] emissions and GHG emission rate average.

Staff notes that mandatory reporting of the GHG emissions provides the necessary information for the California Air Resources Board to develop greenhouse gas regulations and/or trading markets required by the California Global Warming Solutions Act of 2006 (AB 32 Núñez, Statutes of 2006, Chapter 488, Health and Safety Code sections 38500 et seq.). The project may be subject to additional reporting requirements and GHG reductions or trading requirements as these regulations are 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 regarding greenhouse gas emissions for this siting case. Future power plant siting cases are likely to be reviewed with the benefit of new information and policy direction from the Energy Commission in response to the OII. This analysis recognizes that "prudent use" of natural gas for electricity generation will serve to optimize the system (for integrating intermittent renewable generation and providing reliability), but, without further analysis and policy direction by the Commission to refine this general understanding, this analysis leaves the implications for optimizing the system to future cases (CEC 2009a).

The operation of LEC would affect the overall electricity system operation and GHG emissions in several ways:

- Lodi Energy Center would provide flexible, dispatchable power necessary to integrate some of the growing generation from intermittent renewable sources, such as wind and solar generation.

[1] Fuel-use closely correlates to carbon dioxide (CO_2) emissions from natural gas-fired power plants. And since CO_2 emissions from the fuel combustion dominate greenhouse gas (GHG) emissions from power plants, CO_2 and GHG are used interchangeably in this section.

- Lodi Energy Center would displace some less efficient local generation in the dispatch order of gas-fired facilities that are required to provide electricity reliability in the Stockton area.
- Lodi Energy Center would facilitate to some degree the replacement of out-of-state high-GHG emitting (e.g., coal-fired) electricity generation that must be phased out in conformance with the State's new Emissions Performance Standard.
- Lodi Energy Center could facilitate to some extent the replacement of generation provided by aging power plants that use once-through cooling.

The ability and magnitude to which Lodi Energy Center would fulfill these roles is uncertain. The proposed LEC would be designed to provide flexible, dispatchable power because it would include rapid startup features, but the applicant has not been able to commit to providing fast-starting capabilities under all conditions until possibly after one full year of operating experience (Response to Workshop Queries 25 and 26, CH2MHILL2009b and CH2M2009c, p. 5.1-26). While the energy displaced by the Lodi Energy Center project would result in a reduction in GHG emissions from the electricity system, the project's role in optimizing the system and its potential GHG benefits are less than ideal for two reasons: 1) the applicant is not able to commit to the proposed technology providing fast-starting capabilities under all conditions, and 2) its proposed location would not be physically within a major local reliability area like the Greater Bay Area. Still, 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 net reduction in GHG emissions from power plants, would not worsen, but would improve, current conditions, and would, thus, not result in impacts that are cumulatively significant.

Staff concludes that the short-term emission of greenhouse gases during construction would be sufficiently reduced by "best practices" and would not be significant.

The project would comply with the limits of the Greenhouse Gas Emission Performance Standard (Title 20, California Code of Regulations, section 2900 et seq.) that applies to utility purchases of base load power from power plants.

INTRODUCTION

Greenhouse gas (GHG) emissions are not criteria pollutants, but they are discussed in the context of cumulative impacts. The state has demonstrated its intent to address global climate change though research, adaptation,[2] and GHG 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.

[2] 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).

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.

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.)	California Global Warming Solutions Act of 2006. This act requires the California Air Resources Board (ARB) to enact standards that will reduce GHG emissions 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.	ARB regulations implementing 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 MTCO2/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lb CO_2/MWh)

GLOBAL CLIMATE CHANGE AND CALIFORNIA

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" (Health & Safety Code, sec. 38500).

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 or global climate change[3] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). Three years later,

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

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.[4] To achieve this, ARB has a mandate to define the 1990 emissions levels 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 significant 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 over 1 megawatt (MW) capacity, and the due date for initial reports by existing facilities this first year was June 1, 2009.

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 the ARB in December 2008 builds upon the overall climate policies of the Climate Action Team report and shows 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) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). The scoping plan includes a 33% Renewables Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade system that includes the electricity sector (ARB 2008c).

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% reduction in GHG from the electricity sector, even though the sector currently only produces about 25% of the state's GHG emissions. In response, in September 2008 the Energy Commission and the California Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified points of regulation within the sector 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

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

2007a). 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% Renewables Portfolio Standard.

SB 1368,[5] enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibit California utilities from entering into long-term commitments with any base load facilities that exceed the Greenhouse Gas Emission Performance Standard of 0.500 metric tonnes CO_2 per megawatt-hour[6] (1,100 pounds CO_2/MWh). Specifically, the SB 1368 Emission Performance Standard (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.[7] 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 complies with the EPS. *Base load* units are defined as units that operate at a capacity factor higher than 60%. As a project applying for the flexibility to operate in base load scenarios, Lodi Energy Center would have to meet the SB 1368 EPS.

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. 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 unavoidably curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). Ancillary services[8] 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.

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[5] Public Utilities Code § 8340 et seq.

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

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

[8] See CEC 2009b, p. 95.

California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system mix. In this context, and because fossil-fueled resources produce GHG emissions, it is important to consider the role and necessity of also adding fossil-fuel resources. A report prepared as a response to the GHG OII (CEC 2009a) defines five roles that gas-fired power plants are likely to fulfill in a high-renewables, low-GHG system (CEC 2009b, pp 93 and 94):

1. Intermittent generation support
2. Local capacity requirements
3. Grid operations support
4. Extreme load and system emergency
5. General energy support.

The Energy Commission staff-sponsored report reasonably assumes that non-renewable power plants added to the system would almost exclusively be natural gas-fueled. Nuclear, geothermal, and biomass plants are generally base load and not dispatchable. Solid fueled projects are also generally base load, not dispatchable and carbon sequestration technologies needed to reduce the GHG emission rates to meet the EPS are not yet developed (CEC 2009b, p. 92). Further, California has almost no sites available to add highly dispatchable hydroelectric generation.

Generation of electricity using any fossil fuel, including natural gas, can produce greenhouse gases with the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. For fossil fuel-fired power plants, the GHG emissions 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 or recycled, but are nevertheless documented here as some of the compounds have very high 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 GHGs are converted into carbon dioxide equivalent (CO2E) metric tonnes (MT) for ease of comparison.

PROJECT CONSTRUCTION

Construction of industrial facilities such as power plants requires coordination of a variety of 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 Lodi Energy Center would involve 24 months of activity, and building the linear facilities would require two months. The applicant provided a GHG emission estimate for the entirety of the construction phase (CH2M2009g) and it appears to rely on fuel use estimates that exceed those in AFC Appendix 5.1-E. This preliminary construction estimate, presented below in

Greenhouse Gas Table 2, includes the total emissions for the 24 months of construction activity in terms of CO_2-equivalent.

Greenhouse Gas Table 2
Lodi Energy Center, Estimated Potential
Construction Greenhouse Gas Emissions

Construction Source	Construction-Phase GHG Emissions (MTCO2E) [a]
Onsite construction	36,383
Deliveries to construction site	1,930
Worker travel to/from construction site	1,888
Construction of linear facilities	284
Deliveries to linear facilities construction areas	155
Worker travel to/from linear facilities construction areas	14
Construction Total	40,654

Source: Response to Data Request 56B, Table DR56B-1 (CH2MHILL2009g).
Notes: a. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms

PROJECT OPERATIONS

The proposed Lodi Energy Center would expand the existing 49 MW Northern California Power Agency (NCPA) Combustion Turbine Project #2 (NCPA STIG plant) by adding a new 296 MW combined cycle power plant. The proposed LEC project would include a new natural gas-fired combustion turbine generator (CTG) and a new steam turbine generator (STG) operating on heat recovered from the CTG exhaust in an un-fired heat recovery steam generator (HRSG). This system would be equipped with rapid startup features designed by Siemens (CH2M2009c), and the proposed CTG and STG would be capable of operating in a highly-efficient base load mode. The project would be equipped with an auxiliary boiler to maintain the temperature of the HRSG and STG, to limit the duration of startups. However, without having operating experience with this type of plant, the applicant has not been able to commit to less than three hours for a cold startup (NCPA2009b). Lodi Energy Center would have the capability to complete hot startups[9] in less than two hours (CH2M2009c).

The proposed Lodi Energy Center project would be permitted to operate as a base load power plant. The primary sources of GHG would be the natural gas fired combustion turbine, the auxiliary boiler, and sulfur hexafluoride emissions from new electrical component equipment. The employee and delivery traffic GHG emissions from off-site activities are negligible in comparison with the gas turbine and boiler GHG emissions.

[9] A *cold startup* for the LEC STG/HRSG system is defined as startup of the combined cycle system following a CTG shutdown lasting at least 12 hours. During a cold startup of the steam turbine system, the CTG system is initially brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue. A *hot startup* is defined as a startup of the combined cycle system following a shutdown of less than 12 hours (NCPA2008a).

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, but are nevertheless documented here as some of the compounds have very high relative global warming potentials. A small amount of additional SF_6 containing equipment will be required for this project, and the leakage of SF_6 and its CO_2 equivalent emissions have been estimated.

Greenhouse Gas Table 3
Lodi Energy Center, Estimated Potential Greenhouse Gas (GHG) Emissions

Emissions Source	**Operational GHG Emissions (MTCO2E/yr)** [a]
Combustion Turbine Generator with Auxiliary Boiler and STG	936,614
Circuit Breakers (SF_6)	23
Worker Commutes – Off-Site	51
Material Deliveries – Off-Site	59
Total Project GHG Emissions, excluding Off-Site Emissions (MTCO2E/yr)	**936,637**
Estimated Annual Energy Output (MWh/yr) [b]	2,592,960
Estimated Annualized GHG Performance (MTCO2/MWh)	**0.361**
Estimated Annualized GHG Performance (MTCO2E/MWh)	**0.361**

Sources: AFC Appendix Table 5.1A-7R (CH2M2009c) and Tables DR57-1 and DR57-3 (CH2MHILL2009g) including methane (CH_4) and nitrous oxide (N_2O).
Notes:
a. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
b. Annualized basis of operation is estimated to be 8,760 hours at 296 MW with 4,000 hours of auxiliary boiler operation (CH2M2009c, Tables 5.1-22R and 5.1A-7R).

The proposed project would be permitted, on an annual basis, to emit over 936,000 metric tonnes of CO_2-equivalent per year if operated at its maximum permitted level. The proposed LEC combined cycle plant, at 0.36 MTCO2/MWh, would easily meet the limits of SB 1368 and the Greenhouse Gas Emission Performance Standard of 0.500 MTCO2/MWh.

The proposed project would increase the available energy and capacity to the electricity system, and the Stockton Local Capacity Area in San Joaquin County and Stanislaus County would likely benefit from the incremental increase in energy and capacity. However, the project would not be physically located in a major local reliability area that has, or is projected to have, capacity shortfalls. A project located in a major load pocket, for example, the Greater Bay Area Local Capacity Area, would be more likely to provide local reliability support and facilitate the retirement of other less-efficient power plants to a degree that the Lodi Energy Center project could not.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses the cumulative effects of GHG emissions caused by both construction and operation. 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. Staff is continuing to monitor development of AB 32 Scoping Plan implementation efforts and general trends and developments affecting GHG regulation in the electricity sector.

The impact of GHG emissions caused by this natural gas-fired facility is characterized by considering how the power plant would affect the overall electricity system. The integrated electricity system depends on 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 role of fossil-fueled power plants in California’s electricity system. The five separate roles that gas-fired power plants are most likely to fulfill in the future of a high-renewables, low-GHG system include: 1) Intermittent generation support; 2) Local capacity requirements; 3) Grid operations support; 4) Extreme load and system emergencies support; and 5) General energy support (CEC 2009b, p. 93). Lodi Energy Center is analyzed here for its role in providing local capacity and generation and general energy support for expected generation retirements or replacements.

CONSTRUCTION IMPACTS

Staff does not believe that the minor GHG emission increases from construction activities would be significant for several reasons. First, the period of construction would be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures that staff recommends to address criteria pollutant emissions, such as limiting idling times and requiring, as appropriate, using equipment that meets the latest criteria pollutant emissions standards would further minimize greenhouse gas emissions to the extent feasible. The use of newer equipment will increase fuel efficiency 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

New, efficient, natural gas-fired generation promotes the state’s efforts to improve overall system efficiencies and, therefore, reduce the amount of natural gas used by electricity generation and greenhouse gas emissions. As the *2007 Integrated Energy Policy Report* (CEC 2007a, 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 Lodi Energy Center project 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 gas-fired power plants are added to: 1) permit the penetration of renewable generation to the 33% target; 2) improve the overall efficiency of the electric system; or 3) serve load growth or capacity needs more efficiently than the existing fleet (CEC 2009b, p. 98). Lodi Energy Center, with its lower heat rate than most other dispatchable gas-fired generation in the state, would be more efficient and lower GHG-emitting than the existing fleet.

The Role of Lodi Energy Center in Local Generation Displacement

The proposed Lodi Energy Center project would have a net heat rate of approximately 6,824 Btu/kWh[10] (CH2M2009c, p. 5.1-21), which leads to an estimated base load annual GHG performance factor of approximately 0.36 MTCO2/MWh. The heat rate, energy output and GHG emissions of other local generation resources are listed in **Greenhouse Gas Table 4**. Compared to most other new and existing units in San Joaquin County and Stanislaus County, the proposed LEC would be more efficient, and emit fewer GHG emissions during any hour of operation. Local generating units with the best (lowest) heat rate or lowest GHG performance factor generally operate more than other units with higher heat rates, as shown by the relative amount of energy (GWh) produced in 2008 from the local units. However, dispatch order can change, or deviate from economic or efficiency dispatch, in any one year or due to other concerns such as permit limits, contractual obligations, droughts, heat waves, local reliability needs or emergencies. These deviations, however, are likely to occur infrequently.

[10] Based on the High Heating Value (HHV) of the fuel(s) used. HHV is used for all heat rate and fuel conversions to GHG mass emissions that are discussed in this document.

Greenhouse Gas Table 4
San Joaquin and Stanislaus Counties, Local Generation
Heat Rates and 2008 Energy Outputs

Plant Name	Heat Rate (Btu/kWh) [a]	2008 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Walnut Energy Center	7,822	1,578	0.415
Woodland 1	8,761	416	0.465
Lodi CC (NCPA STIG)	9,000	72	0.477
Almond Power Plant	11,074	62	0.587
MID Ripon	11,908	33	0.631
McClure 1, 2	15,222	18	0.807
Tracy Peaker Plant	12,310	11	0.652
Walnut (Peaker)	19,098	1	1.013
Proposed Lodi Energy Center (at permitted limit)	6,824	2,593 (max est.)	0.361

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER); with Lodi Energy Center estimated to operate on annualized basis of 8,760 hours at 296 MW (CH2M2009c, Table 5.1A-7R).
Notes: a. Based on the Higher Heating Value or HHV of the fuel.

While Lodi Energy Center is located inside the Stockton Local Capacity Area, it would not be physically within a major local reliability area like the Greater Bay Area, where it would be more likely to provide local reliability and displace other power plants.

The Role of Lodi Energy Center in the Integration of Renewable Energy

As California moves towards an increased reliance on renewable energy, the bulk of renewable generation available to, and used in California, will be intermittent wind generation with some intermittent solar (CEC 2009b, p.3). To accommodate the increased variability in generation due to increasing renewable penetration, compounded by increasing load variability, control authorities such as the California Independent System Operator (CAISO) need increased flexibility from other generation resources such as hydro generation, dispatchable pump loads, energy storage systems, and fast ramping and fast starting fossil fuel generation resources (CAISO 2007, p. 14).

Lodi Energy Center would provide flexible, dispatchable and fast ramping[11] power that would not obstruct penetration of renewable energy. In general, combined cycle combustion turbines can ramp up quickly, but the combined cycle facility overall output is limited to about 15 MW per minute[12] by the steam turbine and HRSG.

[11] The CAISO categorizes *fast-ramping* as a generator capable of going from lowest power to highest in under 20 minutes, or greater than 10 MW per minute.

[12] Of the 2,821 MW of thermal resources providing Ancillary Services to the CAISO, most (2,441 MW) have ramp rates between 10 and 31 MW/min. The bulk of the resources providing Ancillary Services with ramp rates greater than 10 MW/min (7,141 MW) are hydroelectric facilities (ISO 2007).

Lodi Energy Center would not, however, provide fast starting[13] capabilities when the HRSG and steam turbine are cold. Although the proposed LEC project would include rapid startup design features, the applicant does not have operating experience for this plant and has not been able to commit to providing fast starting capabilities under all conditions (CH2MHILL2009b and 2009c). Intermittent renewable sources of energy would be accommodated by Lodi Energy Center varying its energy output as needed to integrate the renewable sources, but the inability to commit to fast-start capabilities under all conditions makes it likely that Lodi Energy Center may not be able to play a role in some system operating scenarios.

The amount of dispatchable fossil fuel generation will have to be significantly increased to meet the 20% RPS (CAISO 2007, p.113); the 33% RPS will require even more dispatchable resources to integrate the renewables. However, this does not suggest the existing and new fossil fuel capacity will operate more. **Greenhouse Gas Table 5** shows how the build-out of either the 20% or the 33% RPS will affect generation from new and existing non-renewable resources. Should California reach its goal of meeting 33% of its retail demand in 2020 with renewable energy, non-renewable, most likely fossil-fueled, energy needs will fall by over 36,000 GWh/year. In other words, all growth will need to come from renewable resources to achieve the 33% RPS. And some existing and new fossil units will generate less energy than they currently do, given the expected growth in retail sales.

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.[14] 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 8,000 to 6,700 GWh/year, depending on whether 33% or 20% RPS is assumed.

The Role of Lodi Energy Center in Retirements/Replacements

Lodi Energy Center would provide up to 2,593 GWh of natural gas-fired 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 resources such as coal-fired generation, generation that relies on water for once-through cooling, and aging power plants (CEC 2007a). Some of the existing plants that are likely to require significant capital investments to continue operation in light of these policies may be unlikely to undertake the investments and will retire or be replaced.

[13] In general, fast starts are defined as being less than two hours.

[14] 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.

Greenhouse Gas Table 5
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% transmission and distribution losses.
b. Based on 8% transmission and distribution losses, or 42,885 GWh x 0.08 = 46,316 GWh.
c. Renewable standards are calculated on retail sales and not on total generation, which accounts for 8% transmission and distribution losses.
d. Based on net energy (including 8% transmission and distribution losses), not based on retail sales.

Replacement of High GHG-Emitting Generation

High GHG-emitting, such as coal-fired, resources are effectively prohibited from entering into new contracts for California 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 existing contracts will have to be replaced; these contracts are listed in **Greenhouse Gas Table 6**.

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[15], all the coal contracts (including those in **Greenhouse Gas Table 6**, 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 not be able to contract with California utilities due to the SB 1368 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 generation. New generation resources generally will emit significantly less GHG than the coal and petroleum coke-fired generation, which average about 1.0 MTCO2/MWh, or almost three times more than new natural gas-fired combined-cycle projects like the LEC, resulting in a significant net reduction in GHG emissions from the California electricity sector.

[15] A carbon adder or carbon tax is a specific value added to the cost of a project 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.

Greenhouse Gas Table 6
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 Emissions Performance Standard, but the Department of Water Resources has stated its intention not to renew or extend.

Retirement of Generation Using Once-Through Cooling

New, dispatchable resources like Lodi Energy Center would also be required to provide generation capacity (that is, the ability to meet fluctuating, intermittent electricity loads) in the likely event that facilities utilizing once-through cooling (OTC) are retired. The State Water Resource Control Board (SWRCB) has proposed significant changes to OTC units, which would likely require retrofit, retirement, or significant 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-cycle plants 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 likely displace the energy provided by OTC facilities and 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 7** provides a summary of the utility and merchant energy supplies affected by the OTC regulations.

Greenhouse Gas Table 7
Aging Units and 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 Area	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 Area	Yes	1,332	180	0.673
Potrero 3	Merchant	S.F. Bay Area	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
Notes: 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.
The Los Angeles Department of Water and Power (LADWP) reported a 2007 aggregate energy number of 4,003 GWh for all the Haynes units. Staff allocated the energy between the units based on Haynes' current and historical output allocations in the LADWP fillings for 2009 IEPR.

New generation resources that can either provide local support or energy will emit significantly less GHGs than aging and/or OTC plants whose generation they could partially displace. Existing aging and OTC natural gas generation averages 0.6 to 0.7 MTCO2/MWh, or less than two times more than new natural gas-fired combined-cycle projects like the LEC. When a new project can provide energy and capacity to displace this existing generation, it can provide a significant net reduction in GHG emissions from the electricity sector. A project located in a load pocket, for example, the Greater Bay Area Local Capacity Area, would more likely provide local reliability support as well as facilitate the retirement of aging and/or OTC power plants to a degree that the Lodi Energy Center project could not.

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 would emit greenhouse gases and, therefore, has been analyzed as a potential cumulative impact in the context of its effect on the electricity system, resulting GHG emissions from the system, and existing GHG regulatory requirements and GHG energy policies.

COMPLIANCE WITH LORS

Ultimately, ARB’s AB 32 regulations are likely to address both the degree of electricity generation sector emissions reductions (through cap-and-trade), and the method by which those reductions will be achieved (e.g., through command-and-control). However, the exact approach to be taken is currently under development. That regulatory approach may address emissions not only from the newer, more efficient, and lower emitting facilities licensed by the Energy Commission, but also from the older, higher-emitting facilities not subject to any GHG reduction standard that this agency could presently impose. This programmatic approach is likely to be more effective in reducing GHG emissions overall from the electricity sector than one that merely relies on displacing out-of-state coal plants (“leakage”) or older “dirtier” facilities.

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 the regulation points should ARB decide that a multi-sector cap-and-trade system is warranted. As ARB codifies accurate GHG inventories and methods, it may become apparent that emission reductions from the generation sector are less cost-effective than other sectors, and that other sectors of sources can achieve reductions with relative ease and cost-effectiveness.

The project would be subject to ARB's mandatory reporting requirements and potentially other future requirements mandating compliance with AB 32 that are being developed by ARB. How the project would comply with these ARB requirements is speculative at this time, but compliance would be mandatory. The ARB's mandatory GHG emissions reporting requirements do not indicate whether the project, as defined, would comply with the potential GHG emissions reduction regulations being formulated under AB 32. The project may have to provide additional reports and GHG reductions, depending on the future regulations expected from ARB.

Reporting of GHG emissions would enable the project to demonstrate consistency with the policies described above and the regulations that ARB adopts and to provide the information to demonstrate compliance with any applicable EPS that could be enacted in the next few years. The Lodi Energy Center project would meet the current Emission Performance Standard in SB 1368.

NOTEWORTHY PUBLIC BENEFITS

Electricity is produced by operation of inter-connected generation resources and, by knowing the fuel used by the generation sector, the resulting GHG emissions can be known. The operation of LEC would affect the overall electricity system operation and GHG emissions in several ways:

- Lodi Energy Center would provide flexible, dispatchable power necessary to integrate some of the growing generation from intermittent renewable sources, such as wind and solar generation.
- Lodi Energy Center would displace some less efficient local generation in the dispatch order of gas-fired facilities that are required to provide electricity reliability in the Stockton area.
- Lodi Energy Center would facilitate to some degree the replacement of out-of-state high-GHG emitting (e.g., coal-fired) electricity generation that must be phased out in conformance with the State's new Emissions Performance Standard.
- Lodi Energy Center could facilitate to some extent the replacement of generation provided by aging power plants that use once-through cooling.

The project would likely lead to 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 the state's power plants, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant. Moreover, it would be consistent with AB 32 goals.

The energy displaced by the proposed LEC project would result in a reduction in GHG emissions from the electricity system. In other system roles, as described in **Greenhouse Gas Table 8**, the ability to minimize its GHG impacts by filling the expected future roles for gas-fired generation, in a high-renewables, low-GHG system, is not well defined for the Lodi Energy Center project due to its location and due to the applicant not being able to commit to providing fast starting capabilities under all conditions.

Greenhouse Gas Table 8
LEC, Summary of Role in Providing Energy and Capacity Resources

Services Provided by Generating Resources	Discussion, Lodi Energy Center
Integration of Renewable Energy	• *Would not* provide fast startup capability (within two hours), except during hot start conditions. • Would provide rapid ramping capability. • Would have ability to provide regulation and reserves, and energy when renewable resources are unavailable.
Local Generation Displacement	• *Would not* be able to satisfy/partially satisfy local capacity area (LCA) resource requirements. • Would provide voltage support. • *Would not* provide black start capability.
Ancillary Services, Grid System, and Emergency Support	• *Would not* provide fast start-up capability (within two hours), except during hot start conditions. • *Would not* have low minimum load levels. • Would provide rapid ramping capability. • Would have ability to provide regulation and reserves. • *Would not* provide black start capability.
General Energy Support	• Would provide general energy support. • Could facilitate some retirements and replacements • Would provide cost-competitive energy. • Would be able to help a load-serving entity (LSE) meet resource adequacy (RA) requirements.

Source: Energy Commission staff; based on: Expected Roles for Gas-Fired Generation (CEC2009b, p. 7).

CONCLUSIONS

Lodi Energy Center would be an efficient, new, dispatchable natural gas-fired combined cycle power plant that would cause GHG emissions while generating electricity for California consumers. AB 32 emphasizes that GHG emission reductions must be “big picture” reductions that do not lead to “leakage” of such reductions to other states or countries. The project’s GHG emissions per MWh would be lower than those of other power plants and peaking projects that the project would displace and, thus, would contribute to continued improvement of the California and overall Western Electricity Coordinating Council system’s GHG emissions and 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 impacts that are cumulatively significant. Other potential GHG benefits gained by the project’s ole in optimizing the system are less defined for Lodi Energy Center with its location outside of a major local reliability area and the applicant not being able to commit to providing fast starting capabilities under all conditions.

Staff notes that mandatory reporting of GHG emissions per Air Resources Board greenhouse gas regulations would occur, and this would enable the ARB to gather the information needed to regulate the LEC in trading markets if required by the regulations implementing the California Global Warming Solutions Act of 2006 (AB 32). The project may be subject to additional reporting requirements and GHG reduction or trading requirements as these regulations are more fully developed and implemented.

Staff does not believe that the minor GHG emission increases from construction activities would be significant for several reasons. First, the period of construction would be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures, or best practices, that staff recommends for minimizing criteria pollutants, 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 would increase fuel efficiency 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 concludes that the short-term emission of greenhouse gases during construction would be substantially reduced and would, therefore, not be significant.

The Lodi Energy Center project would meet the Emission Performance Standard of SB 1368.

PROPOSED CONDITIONS OF CERTIFICATION

None proposed. The project owner would comply with mandatory ARB GHG emissions reporting regulations (California Code of Regulations, tit. 17, section 95100 et. seq.) and/or future GHG regulations formulated by the ARB, such as limits set by GHG emissions cap and trade markets.

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CULTURAL RESOURCES QUALITY

Testimony of Beverly E. Bastian

CONDITIONS OF CERTIFICATION

CUL-1 Prior to the start of ground disturbance, the project owner shall obtain the services of a Cultural Resources Specialist (CRS), and one or more alternate CRSs, if alternates are needed. The CRS shall manage all monitoring, mitigation, curation, and reporting activities required in accordance with the Conditions of Certification (Conditions). The CRS may elect to obtain the services of Cultural Resources Monitors (CRMs) and other technical specialists, if needed, to assist in monitoring, mitigation, and curation activities. The project owner shall ensure that the CRS makes recommendations regarding the eligibility for listing in the California Register of Historical Resources (CRHR) of any cultural resources that are newly discovered or that may be affected in an unanticipated manner. No ground disturbance shall occur prior to CPM approval of the CRS and alternates, unless such activities are specifically approved by the CPM. Approval of a CRS may be denied or revoked for reasons including but not limited to non-compliance on this or other Energy Commission projects.

CULTURAL RESOURCES SPECIALIST

The resumes for the CRS and alternate(s) shall include information demonstrating to the satisfaction of the CPM that their training and backgrounds conform to the U.S. Secretary of Interior's Professional Qualifications Standards, as published in Title 36, Code of Federal Regulations, part 61. In addition, the CRS shall have the following qualifications:

1. The CRS's qualifications shall be appropriate to the needs of the project and shall include a background in anthropology, archaeology, history, architectural history, or a related field;
2. At least three years of archaeological or historical, as appropriate (per nature of predominant cultural resources on the project site), resource mitigation and field experience in California; and
3. At least one year of experience in a decision-making capacity on cultural resources projects in California and the appropriate training and experience to knowledgably make recommendations regarding the significance of cultural resources.

The resumes of the CRS and alternate CRS shall include the names and telephone numbers of contacts familiar with the work of the CRS/alternate CRS on referenced projects and demonstrate to the satisfaction of the CPM that the CRS/alternate CRS has the appropriate training and experience to implement effectively the Conditions.

CULTURAL RESOURCES MONITORS

CRMs shall have the following qualifications:

1. a B.S. or B.A. degree in anthropology, archaeology, historical archaeology or a related field and one year experience monitoring in California; or
2. an A.S. or A.A. degree in anthropology, archaeology, historical archaeology or a related field, and four years experience monitoring in California; or
3. enrollment in upper division classes pursuing a degree in the fields of anthropology, archaeology, historical archaeology or a related field, and two years of monitoring experience in California.

CULTURAL RESOURCES TECHNICAL SPECIALISTS

The resume(s) of any additional technical specialist(s), e.g., historical archaeologist, historian, architectural historian, and/or physical anthropologist, shall be submitted to the CPM for approval.

<u>Verification:</u>

1. At least 45 days prior to the start of ground disturbance, the project owner shall submit the resume for the CRS, and alternate(s) if desired, to the CPM for review and approval.
2. At least 10 days prior to a termination or release of the CRS, or within 10 days after the resignation of a CRS, the project owner shall submit the resume of the proposed new CRS to the CPM for review and approval. At the same time, the project owner shall also provide to the proposed new CRS the AFC and all cultural resources documents, field notes, photographs, and other cultural resources materials generated by the project. If there is no alternate CRS in place to conduct the duties of the CRS, a previously approved monitor may serve in place of a CRS so that project-related ground disturbance may continue up to a maximum of 3 days without a CRS. If cultural resources are discovered then ground disturbance will remain halted until there is a CRS or alternate CRS to make a recommendation regarding significance.
3. At least 20 days prior to ground disturbance, the CRS shall provide a letter naming anticipated CRMs for the project and stating that the identified CRMs meet the

minimum qualifications for cultural resources monitoring required by this Condition. If additional CRMs are obtained during the project, the CRS shall provide additional letters to the CPM identifying the CRMs and attesting to the qualifications of the CRMs, at least 5 days prior to the CRMs beginning on-site duties.

4. At least 10 days prior to any technical specialists beginning tasks, the resume(s) of the specialists shall be provided to the CPM for review and approval.
5. At least 10 days prior to the start of ground disturbance, the project owner shall confirm in writing to the CPM that the approved CRS will be available for onsite work and is prepared to implement cultural resources Conditions.

CUL-2 Prior to the start of ground disturbance, the project owner shall provide to the CRS, if the CRS has not previously worked on the project, copies of the AFC, data responses, confidential cultural resources reports, all supplements, and the Energy Commission’s Staff Assessment (SA) for the project. The project owner shall also provide the CRS and the CPM with maps and drawings showing the footprints of the power plant, all linear facility routes, all access roads, and all laydown areas. Maps shall include the appropriate USGS quadrangles and a map at an appropriate scale (e.g., 1:2000 or 1” = 200’) for plotting cultural features or materials. If the CRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the CRS and CPM. The CPM shall review map submittals and, in consultation with the CRS, approve those that are appropriate for use in cultural resources planning activities. No ground disturbance shall occur prior to CPM approval of maps and drawings, unless such activities are specifically approved by the CPM.

If construction of the project would proceed in phases, maps and drawings not previously provided shall be provided to the CRS and CPM prior to the start of each phase. Written notice identifying the proposed schedule of each project phase shall be provided to the CRS and CPM.

Weekly, until ground disturbance is completed, the project construction manager shall provide to the CRS and CPM a schedule of project activities for the following week, including the identification of area(s) where ground disturbance will occur during that week.

The project owner shall notify the CRS and CPM of any changes to the scheduling of the construction phases.

Verification:

1. At least 40 days prior to the start of ground disturbance, the project owner shall provide copies of the AFC, data responses, confidential cultural resources documents, all supplements, and the Energy Commission SA to the CRS (if needed) and copies of the subject maps and drawings to the PG, CRS, and CPM. The CPM will review submittals in consultation with the CRS and approve maps and drawings suitable for cultural resources planning activities.
2. At least 15 days prior to the start of ground disturbance, if there are changes to any project-related footprint, the project owner shall provide revised maps and drawings for the changes to the CRS and CPM.
3. At least 15 days prior to the start of each phase of a phased project, the project owner shall submit the appropriate maps and drawings, if not previously provided, to the CRS and CPM.
4. Weekly, during ground disturbance, a current schedule of anticipated project activity shall be provided to the CRS and CPM by letter, e-mail, or fax.
5. Within 5 days of changing the scheduling of phases of a phased project, the project owner shall provide written notice of the changes to the CRS and CPM.

CUL-3 Prior to the start of ground disturbance, the project owner shall submit the Cultural Resources Monitoring and Mitigation Plan (CRMMP), as prepared by or under the direction of the CRS, to the CPM for review and approval. The CRMMP shall follow the content and organization of the draft model CRMMP, provided by the CPM, and the author’s name shall appear on the title page of the CRMMP. The CRMMP shall identify general and specific measures to minimize potential impacts to sensitive cultural resources and shall incorporate the results of the geoarchaeological field study as reported to the CRS in the draft technical report for that study. Implementation of the CRMMP shall be the responsibility of the CRS and the project owner. Copies of the CRMMP shall reside with the CRS, alternate CRS, each CRM, and the project owner’s on-site construction manager. No ground disturbance shall occur prior to CPM approval of the CRMMP, unless such activities are specifically approved by the CPM.

The CRMMP shall include, but not be limited to, the following elements and measures:

1. The following statement included in the Introduction: “Any discussion, summary, or paraphrasing of the Conditions of Certification in this CRMMP is intended as general guidance and as an aid to the user in understanding the conditions and their implementation. The conditions, as

written in the Commission Decision, shall supersede any summarization, description, or interpretation of the conditions in the CRMMP. The Cultural Resources Conditions of Certification from the Commission Decision are contained in Appendix A."

2. An archaeological research design, scoped, to the extent feasible, to the time periods and the archaeological resource types, if any, established by the geoarchaeological field study, that includes a discussion of research questions and testable hypotheses applicable to the project's construction areas;
3. A discussion of artifact collection, retention/disposal, and curation policies as related to the research questions formulated in the research design. A prescriptive treatment plan may be included in the CRMMP for limited data types;
4. A description of the manner in which Native American observers or monitors will be included, the procedures to be used to select them, and their role and responsibilities;
5. A statement that all cultural resources encountered shall be recorded on Department of Parks and Recreation (DPR) 523 forms and mapped and photographed. In addition, all archaeological materials retained as a result of the archaeological investigations (survey, testing, data recovery) shall be curated in accordance with the California State Historical Resources Commission's *Guidelines for the Curation of Archaeological Collections*, into a retrievable storage collection in a public repository or museum;
6. A statement that the project owner will pay all curation fees for artifacts recovered, if any, and for related documentation produced during cultural resources investigations conducted for the project. The project owner shall identify three possible curation facilities that could accept cultural resources materials resulting from project activities;
7. A statement that the CRS has access to equipment and supplies necessary for site mapping, photography, and recovery of any cultural resource materials that are encountered during ground disturbance and cannot be treated prescriptively; and
8. A description of the contents and format of the final Cultural Resource Report (CRR), if any which shall be prepared according to Archaeological Resource Management Report (ARMR) guidelines.

Verification:

1. Upon approval of the CRS proposed by the project owner, the CPM will provide to the CRS an electronic copy of the draft model CRMMP.

2. At least 30 days prior to the start of ground disturbance, the project owner shall submit the subject CRMMP to the CPM for review and approval of the entire CRMMP.
3. At least 30 days prior to the start of ground disturbance, in a letter to the CPM, the project owner shall agree to pay curation fees for any materials collected as a result of the archaeological investigations (survey, testing, data recovery).

CUL-4 If any archaeological monitoring or data recovery activities are conducted during project construction, the project owner shall submit the final Cultural Resources Report (CRR) to the CPM for approval. The final CRR shall be written by or under the direction of the CRS and shall be provided in the ARMR format. The final CRR shall report on all field activities including dates, times and locations, evaluations, data recovery, samplings, analyses, and results. All survey reports, DPR 523 forms, data recovery reports, and any additional research reports not previously submitted to the California Historical Resource Information System (CHRIS) and the State Historic Preservation Officer (SHPO) shall be included as appendices to the final CRR.

If the project owner requests a suspension of ground disturbance and/or construction activities, then a draft CRR that covers all cultural resources activities associated with the project shall be prepared by the CRS and submitted to the CPM for review and approval on the same day as the suspension/extension request. The draft CRR shall be retained at the project site in a secure facility until ground disturbance and/or construction resumes or the project is withdrawn. If the project is withdrawn, then a final CRR shall be submitted to the CPM for review and approval at the same time as the withdrawal request.

<u>Verification:</u>

1. Within 90 days after completion of ground disturbance (including landscaping), the project owner shall submit the final CRR to the CPM for review and approval. If any reports have previously been sent to the CHRIS, then receipt letters from the CHRIS or other verification of receipt shall be included in an appendix.
2. Within 90 days after completion of ground disturbance (including landscaping), if cultural materials requiring curation were collected, the project owner shall provide to the CPM a copy of an agreement with, or other written commitment from, a curation facility that meets the standards stated in the California State Historical Resources Commission's Guidelines for the Curation of Archaeological Collections, to accept

cultural materials, if any, from this project. Any agreements concerning curation will be retained and available for audit for the life of the project.

3. Within 10 days after CPM approval of the CRR, the project owner shall provide documentation to the CPM confirming that copies of the final CRR have been provided to the SHPO, the CHRIS, the curating institution, if archaeological materials were collected, and to the Tribal Chairpersons of any Native American groups requesting copies of project-related reports.
4. Within 30 days after requesting a suspension of construction activities, the project owner shall submit a draft CRR to the CPM for review and approval.

CUL-5 Prior to and for the duration of ground disturbance, the project owner shall provide Worker Environmental Awareness Program (WEAP) training to all new workers within their first week of employment at the project site, laydown area, and along the linear facilities routes. The training shall be prepared by the CRS, may be conducted by any member of the archaeological team, and may be presented in the form of a video. The CRS shall be available (by telephone or in person) to answer questions posed by employees. The training may be discontinued when ground disturbance is completed or suspended, but must be resumed when ground disturbance, such as landscaping, resumes. The training shall include:

1. A discussion of applicable laws and penalties under the law;
2. Samples or visuals of artifacts that might be found in the project vicinity;
3. A discussion of what such artifacts may look like when partially buried, or wholly buried and then freshly exposed;
4. A discussion of what prehistoric and historical archaeological deposits look like at the surface and when exposed during construction, and the range of variation in the appearance of such deposits;
5. Instruction that the CRS, alternate CRS, and CRMs have the authority to halt project-related ground disturbance in the area of a discovery to an extent sufficient to ensure that the resource is protected from further impacts, as determined by the CRS;
6. Instruction that employees are to halt work on their own in the vicinity of a potential cultural resources discovery and shall contact their supervisor and the CRS or CRM, and that redirection of work would be determined by the construction supervisor and the CRS;
7. An informational brochure that identifies reporting procedures in the event of a discovery;
8. An acknowledgement form signed by each worker indicating that they have received the training; and

9. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

No ground disturbance shall occur prior to implementation of the WEAP program, unless such activities are specifically approved by the CPM.

Verification:

1. At least 30 days prior to the beginning of ground disturbance, the CRS shall provide the training program draft text and graphics and the informational brochure to the CPM for review and approval.
2. At least 15 days prior to the beginning of ground disturbance, the CPM will provide to the project owner a WEAP Training Acknowledgement form for each WEAP-trained worker to sign.
3. On a monthly basis, until ground disturbance is completed, the project owner shall provide in the Monthly Compliance Report (MCR) the WEAP Training Acknowledgement forms of workers who have completed the training in the prior month and a running total of all persons who have completed training to date.

CUL-6 Based on the findings of the geoarchaeological study, no archaeological monitoring is required unless WEAP-trained construction workers identify cultural resources materials during excavations. In that event, construction shall cease in the vicinity of the discovery, the CRS shall be notified, and CUL-7 shall apply. When construction is resumed in the vicinity of a discovery, the project owner shall ensure that the CRS, alternate CRS, or CRMs monitor ground disturbance in the vicinity of the discovery until the CRS requests approval from the CPM to change the level of monitoring. The provisions of this condition shall apply to any monitoring necessitated by cultural resources discoveries.

The research design in the CRMMP shall govern the collection, treatment, retention/disposal, and curation of any archaeological materials encountered.

A Native American monitor shall be obtained to monitor ground disturbance if Native American artifacts are encountered during ground disturbance. Contact lists of interested Native Americans and guidelines for monitoring shall be obtained from the Native American Heritage Commission. Preference in selecting a monitor shall be given to Native Americans with traditional ties to the area that shall be monitored. If efforts to obtain the services of a qualified Native American monitor are unsuccessful, the project owner shall immediately inform the CPM. The CPM will either identify potential monitors or will allow ground disturbance to proceed without a Native American monitor.

Full-time archaeological monitoring for this project shall be the archaeological monitoring of the earth-removing activities in the areas specified in the previous two paragraphs, for as long as the activities are ongoing. Full-time archaeological monitoring shall require at least two monitors per excavation area, where excavation equipment is actively removing dirt and hauling the excavated material further than fifty feet from the location of active excavation. In such a scenario, one monitor shall observe the location of active excavation and a second monitor shall inspect the dumped material. For excavation areas where the excavated dirt is dumped no further than fifty feet from the location of active excavation, one monitor shall both observe the location of active excavation and inspect the dumped material.

On forms provided by the CPM, CRMs shall keep a daily log of any monitoring and other cultural resources activities and any instances of non-compliance with the Conditions and/or applicable LORS. Copies of the daily monitoring logs shall be provided by the CRS to the CPM, if requested by the CPM. From these logs, the CRS shall compile a monthly monitoring summary report to be included in the MCR. If there are no monitoring activities, the summary report shall specify why monitoring has been suspended.

During monitoring the CRS or alternate CRS shall report daily to the CPM on the status of cultural resources-related activities at the project site, unless reducing or ending daily reporting is requested by the CRS and approved by the CPM.

In the event that the CRS believes that the current level of monitoring is not appropriate in certain locations, a letter or e-mail detailing the justification for changing the level of monitoring shall be provided to the CPM for review and approval prior to any change in the level of monitoring.

The CRS, at his or her discretion, or at the request of the CPM, may informally discuss cultural resources monitoring and mitigation activities with Energy Commission technical staff.

Cultural resources monitoring activities are the responsibility of the CRS. Any interference with monitoring activities, removal of a monitor from duties assigned by the CRS, or direction to a monitor to relocate monitoring activities by anyone other than the CRS shall be considered non-compliance with these Conditions.

Upon becoming aware of any incidents of non-compliance with the Conditions and/or applicable LORS, the CRS and/or the project owner shall notify the CPM by telephone or e-mail within 24 hours. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the Conditions. When the issue is resolved, the CRS shall write a report describing the issue, the resolution of the issue, and the effectiveness of the resolution measures. This report shall be provided in the next MCR for the review of the CPM.

Verification:

1. At least 30 days prior to the start of ground disturbance, the CPM will provide to the CRS an electronic copy of a form to be used as a daily monitoring log.
2. Monthly, while monitoring is on-going, the project owner shall include in each MCR a copy of the monthly summary report of cultural resources-related monitoring prepared by the CRS and shall attach any new DPR 523A forms completed for finds treated prescriptively, as specified in the CRMMP.
3. At least 24 hours prior to implementing a proposed change in monitoring level, the project owner shall submit to the CPM, for review and approval, a letter or e-mail (or some other form of communication acceptable to the CPM) detailing the CRS's justification for changing the monitoring level.
4. Daily, as long as no cultural resources are found, the CRS shall provide a statement that "no cultural resources over 50 years of age were discovered" to the CPM as an e-mail or in some other form of communication acceptable to the CPM.
5. At least 24 hours prior to reducing or ending daily reporting, the project owner shall submit to the CPM, for review and approval, a letter or e-mail (or some other form of communication acceptable to the CPM) detailing the CRS's justification for reducing or ending daily reporting.
6. No later than 30 days following the discovery of any Native American cultural materials, the project owner shall submit to the CPM copies of the information transmittal letters sent to the Chairpersons of the Native American tribes or groups who requested the information. Additionally, the project owner shall submit to the CPM copies of letters of transmittal for all subsequent responses to Native American requests for notification, consultation, and reports and records.
7. Within 15 days of receiving them, the project owner shall submit to the CPM copies of any comments or information provided by Native Americans in response to the project owner's transmittals of information.

CUL-7 The project owner shall grant authority to halt project-related ground disturbance to the CRS, alternate CRS, and the CRMs in the event of a discovery. Redirection of ground disturbance shall be accomplished under the direction of the construction supervisor in consultation with the CRS.

In the event a cultural resource over 50 years of age (or if younger, determined exceptionally significant by the CPM) is found, or impacts to such a resource can be anticipated, ground disturbance shall be halted or redirected in the immediate vicinity of the discovery sufficient to ensure that the resource is protected from further impacts. The halting or redirection of ground disturbance shall remain in effect until the CRS has visited the discovery, and all of the following have occurred:

1. The CRS has notified the project owner, and the CPM has been notified within 24 hours of the discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning, including a description of the discovery (or changes in character or attributes), of the action taken (i.e., work stoppage or redirection), a recommendation of CRHR eligibility, and recommendations for data recovery from any cultural resources discoveries, whether or not a determination of CRHR eligibility has been made.
2. If the discovery would be of interest to Native Americans, the CRS has notified all Native American groups that expressed a desire to be notified in the event of such a discovery.
3. The CRS has completed field notes, measurements, and photography for a DPR 523 “Primary” form. The “Description” entry of the DPR 523 “Primary” form shall include a recommendation on the CRHR eligibility of the discovery. The project owner shall submit completed forms to the CPM.
4. The CRS, the project owner, and the CPM have conferred, and the CPM has concurred with the recommended eligibility of the discovery and approved the CRS’s proposed data recovery, if any, including the curation of the artifacts, or other appropriate mitigation; and any necessary data recovery and mitigation have been completed.

<u>Verification:</u>

1. At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM and CRS with a letter confirming that the CRS, alternate CRS, and CRMs have the authority to halt project-related ground disturbance in the vicinity of a cultural resources discovery, and that the project owner shall ensure that the CRS notifies the CPM within 24 hours of a discovery, or by Monday morning if the cultural

resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning.

2. Within 48 hours of the discovery of an archaeological or ethnographic resource, the project owner shall ensure that the CRS notifies all Native American groups that expressed a desire to be notified in the event of such a discovery.
3. Unless the discovery can be treated prescriptively, as specified in the CRMMP, completed DPR523 forms for resources newly discovered during ground disturbance shall be submitted to the CPM for review and approval no later than 24 hours following the notification of the CPM, or 48 hours following the completion of data recordation/recovery, whichever the CRS decides is more appropriate for the subject cultural resource.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE *Lodi Energy Center*

DOCKET NO. 08-AFC-10

PROOF OF SERVICE
(Revised 2/17/09)

APPLICANT

Ken Speer
Assistant General Manager
Northern California
Power Agency
651 Commerce Drive
Roseville, CA 95678
ken.speer@ncpagen.com

Ed Warner
Project Manager
Northern California
Power Agency
P.O. Box 1478
Lodi, CA 95241
ed.warner@ncpagen.com

APPLICANT'S COUNSEL

Scott Galati
Galati Blek
455 Capitol Avenue, Ste. 350
Sacramento, CA 95814
sgalati@gb-llp.com

APPLICANT'S CONSULTANT

Andrea Grenier
Grenier & Associates, Inc.
1420 E. Roseville Pkwy,
Ste. 140-377
Roseville, CA 95661
andrea@agrenier.com

Sarah Madams
CH2MHILL
2485 Natomas Park Drive,
Ste. 600
Sacramento, CA 95833
smadams@ch2m.com

APPLICANT'S ENGINEER

Steven Blue
Project Manager
Worley Parsons
2330 E. Bidwell, Ste. 150
Folsom, CA 95630
Steven.Blue@WorleyParsons.com

INTERESTED AGENCIES

California ISO
e-recipient@caiso.com

INTERVENORS

ENERGY COMMISSION

Karen Douglas
Chairman and Presiding
Member
kldougla@energy.state.ca.us

Jeffrey D. Byron
Commissioner and Associate
Member
jbyron@energy.state.ca.us

Kenneth Celli
Hearing Officer
kcelli@energy.state.ca.us

Rod Jones
Project Manager
rjones@energy.state.ca.us

Melanie Moultry
Staff Counsel
MMoultry@energy.state.ca.us

Elena Miller
Public Adviser
publicadviser@energy.state.ca.us

DECLARATION OF SERVICE

I, Teraja` Golston, declare that on January 28, 2010, I served and filed copies of the attached (08-AFC-10) Lodi Energy - Exhibit 303 - Addendum To Staff Assessment. The original documents, filed with the Docket Unit, are accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[www.energy.ca.gov/sitingcases/lodi]**. The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

FOR SERVICE TO ALL OTHER PARTIES:

✓ sent electronically to all email addresses on the Proof of Service list;

✓ by personal delivery or by depositing in the United States mail at Sacramento, California with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses **NOT** marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

✓ **sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (preferred method);**

OR

____ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 08-AFC-10
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

Original in Dockets
Teraja` Golston