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AIR QUALITY

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SUMMARY OF CONCLUSIONS

With the adoption of the attached conditions of certification, the proposed Carlsbad Energy Center Project (CECP) would conform with applicable federal, state and San Diego Air Pollution Control District air quality laws, ordinances, regulations and standards, and that the proposed Carlsbad Energy Center Project would not result in significant air quality related impacts.

All air quality issues related to the project have been addressed in the San Diego Air Pollution Control District's (District) Final Determination of Compliance (FDOC) and through additional staff recommended Conditions of Certification stipulated to by the applicant. The project has secured emission reduction credits in sufficient quantity to meet local air district requirements, and with staff's recommended Condition **AQ-SC10** will create or obtain sufficient emission reduction to fully mitigate all nonattainment pollutants and their precursors at a minimum ratio of one-to-one.

Staff has assessed both the potential for localized impacts and regional impacts for the project's construction and operation, and as a product of this analysis staff has recommended mitigation and monitoring requirements that should provide adequate mitigation and monitoring sufficient to reduce the adverse construction and operating emission impacts to less than significant.

Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in **Appendix Air-1**. The Carlsbad Energy Center Project would replace less efficient existing facilities with lower emissions of carbon dioxide per megawatt hour (CO_2/MWh), and would emit approximately 0.404 metric tonnes of carbon dioxide per megawatt hour (MTCO2/MWh). The project, as a peaking or mid-merit project with an enforceable operating limitation less than 60 percent of capacity, is not subject to the requirements of SB1368 (Perata, Chapter 598, Statutes of 2006) and the Emission Performance Standard.

Staff notes that mandatory reporting of greenhouse gas 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, Chapter 488, Statutes of 2006). The project would emit as much as 0.8 million metric tonnes of carbon dioxide equivalent emissions and therefore would be subject to mandatory GHG reporting requirements. It may also be subject to GHG reductions or trading requirements as these regulations are implemented.

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants due to the construction and operation of the proposed Carlsbad Energy Center Project (CECP) by Carlsbad Energy Center LLC (applicant). The CECP would

be located in Carlsbad at the existing NRG owned Encina Power Plant located west of Interstate 5 and north of Cannon Road.

Criteria air pollutants are defined as those 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), Respirable Particulate Matter (PM10), and Fine Particulate Matter (PM2.5). In addition, Volatile Organic Compounds (VOC) emissions are analyzed because they are precursors to both O_3 and particulate matter. Because NO_2 and SO_2 readily react in the atmosphere to form other oxides of nitrogen and sulfur respectively, the terms nitrogen oxides (NOx) and sulfur oxides (SOx) are also used when discussing these two pollutants.

In carrying out the analysis, the California Energy Commission staff evaluated the following major points:

- Whether CECP is likely to conform with applicable Federal, State and San Diego Air Pollution Control District (SDAPCD or District) air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- Whether CECP is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards (Title 20, California Code of Regulations, section 1742 (b)); and
- Whether the mitigation proposed for CECP is adequate to lessen the 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 mitigation of air quality impacts. Staff's analysis examines the project's compliance with these requirements.

AIR QUALITY Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) 52	Nonattainment New Source Review (NSR) requires a permit and requires Best Available Control Technology (BACT) and Offsets. Permitting and enforcement are delegated to SDAPCD. Prevention of Significant Deterioration (PSD) requires major sources or major modifications to major sources to obtain permits for attainment pollutants. The CECP is a modification of an existing major source and thus the trigger levels are 40 tons per year of NOx or VOC or SOx, 15 tons per year of PM10, or 100 tons per year of CO.
40 CFR 60 Subpart KKKK	New Source Performance Standard for Stationary Combustion Turbines: 15 parts per million (ppm) NOx at 15 percent O_2 and fuel sulfur limit of 0.060 lb SOx per million Btu heat input. BACT would be more restrictive.
40 CFR 60 Subpart IIII	New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines. Establishes emission standards for compression ignition internal combustion engines, including emergency fire water pump engines.
40 CFR Part 70	Title V: Federal permit. Title V permit application is required within one year of start of operation. Permitting and enforcement are delegated to SDAPCD.
40 CFR Part 72	Acid Rain Program. Requires permit and obtaining sulfur oxides credits. Permitting and enforcement are delegated to SDAPCD.
State	
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with Air Resource Board (ARB) approved Clean Air Plans.
HSC Section 41700	Restricts emissions that would cause nuisance or injury.
California Code of Regulations (CCR) Section 93115	Airborne Toxics Control Measure for Stationary Compression Ignition Engines. Limits the types of fuels allowed, establishes maximum emission rates, establishes recordkeeping requirements.
Local – San Diego Air Pollution Control District (SDAPCD) Rule and Regulations	
Regulation II – Permits	This regulation sets forth the regulatory framework of the application for and issuance of construction and operation permits for new, altered and existing equipment. Included in these requirements are the federally delegated requirements for New Source Review, Title V Permits, and the Acid Rain Program. Regulation II Rule 20.1 and 20.3 establishes the pre-construction review requirements for new, modified or relocated facilities, in conformance with the federal New Source Review regulation to ensure that these facilities do not interfere with progress in attainment of the national ambient air quality standards and that future economic growth in the San Diego County is not unnecessarily restricted. This regulation establishes Best Available Control Technology (BACT) and emission offset requirements.

Applicable Law	Description
Regulation IV – Prohibitions	This regulation sets forth the restrictions for visible emissions, odor nuisance, fugitive dust, various air emissions, and fuel contaminants. This regulation also specifies additional performance standards for stationary gas turbines and other internal combustion engines. However, for this project these provisions are less strict than the new source rule requirements of Regulation II.
Regulation X – National Standards of Performance (NSPS) for New Stationary Sources	Regulation X incorporates provisions of 40 CFR Part 60, Chapter I, and is applicable to all new, modified, or reconstructed sources of air pollution. Sections of this federal regulation apply to stationary gas turbines (40 CFR Part 60 Subpart KKKK) and emergency fire pump engines (40 CFR Part 60 Subpart IIII) as described above in the Federal LORS description. Subpart KKKK establish limits of NO_2 and SO_2 emissions from the facility as well as monitoring and test method requirements. Subpart IIII establishes emission standards for compression ignition internal combustion engines. SDAPCD is delegated enforcement authority for these NSPS through their authority to issue and enforce the Title V permit for this existing Title V source.
Regulation XI – National Emission Standards for Hazardous Air Pollutants	Regulation XI adopts federal standards for hazardous air pollutants (40 CFR Section 63) by reference. No such standards presently exist that would apply to the project.
Regulation XII – Toxic Air Contaminants – New Source Review	Regulation XII, Rule 1200, establishes the pre-construction review requirements for new, modified or relocated sources of toxic air contaminants, including requirements for Toxics Best Available Control Technology (T-BACT) if the incremental project risk exceeds rule triggers.
Regulation XIV – Title V Operating Permits	Regulation XIV, Rule 1401 defines the permit application and issuance as well as compliance requirements associated with the Title V federal permit program. Any new source which qualifies as a Title V facility must obtain a Title V permit within twelve months of starting operation. Regulation II, Rule 1412 defines the requirements for the Acid Rain Program, including the requirement for a subject facility to obtain emission allowances for SOx emissions as well as monitoring SOx, NOx, and carbon dioxide (CO_2) emissions from the facility.

SETTING

METEOROLOGICAL CONDITIONS

The climate of San Diego County is controlled by a semi-permanent subtropical high-pressure system that is located off the Pacific Ocean. In the summer, this strong high-pressure system results in clear skies, high temperatures, and low humidity. Very little precipitation occurs during the summer months because storms are blocked by the high-pressure system. Beginning in the fall and continuing through the winter, the high pressure weakens and moves south, allowing storm systems to move through the area. Temperature, winds, and rainfall are more variable during these months, and stagnant conditions occur more frequently than during summer months. Weather patterns include

periods of stormy weather with rain and gusty winds, clear weather that can occur after a storm, or persistent marine layer conditions, with our without ground fog, that can occur during extended parts of the year. The City of Carlsbad receives an average of 11 inches of rain annually (WC 2008).

Temperature, wind speed, and wind direction data collected in Camp Pendleton, about 6.3 miles north northwest of the project site, were processed and provided to the applicant by the SDAPCD (Sierra 2007). The specific location of this meteorological station is approximately one-half mile from the surf zone, on the ocean side of the I-5 Freeway, and should represent the local weather patterns, including persistent marine layer and fog conditions, nearly identical to the project site. The most predominant annual wind direction from this monitoring site is onshore from the southwest to the west northwest with a strong secondary northeast to east northeast offshore component. Onshore winds are the most predominant during both the 2nd and 3rd quarters. The winds during the 1st and 4th quarters have a more predominate offshore component. In all cases, annual and quarterly, the wind frequencies outside of the previously stated predominate onshore and offshore directions are fairly low. The average wind speed is 5.3 miles per hour, and dead calm hours occur less than one percent of the time. The wind speeds are generally higher during daylight hours, and are highest during the 1st and 2nd quarters.

Along with the wind flow, atmospheric stability and mixing heights are important factors in the determination of pollutant dispersion. Atmospheric stability reflects the amount of atmospheric turbulence and mixing. In general, the less stable an atmosphere, the greater the turbulence, which results in more mixing and better dispersion. The mixing height, measured from the ground upward, is the height of the atmospheric layer in which convection and mechanical turbulence promote mixing. Good ventilation results from a high mixing height and at least moderate wind speeds within the mixing layer. In general, mixing is more limited at night and in the winter in San Diego County when there is a higher potential for lower level inversion layers being present along with low speed surface winds.

EXISTING AIR QUALITY

The project is located within the jurisdiction of the San Diego Air Pollution Control District (District). The applicable federal and California ambient air quality standards (AAQS) are presented in **AIR QUALITY Table 2**. As indicated in this table, the averaging times for the various air quality standards (the duration over which they are measured) range from one-hour to annual average. The standards are read as a mass fraction, in parts per million (ppm), or as a concentration, in milligrams or micrograms of pollutant per cubic meter of air (mg/m^3 or µg/m^3).

The U.S. Environmental Protection Agency (U.S. EPA), California Air Resource Board (ARB), and the local air district classify an area as attainment, unclassified, or nonattainment, depending on whether or not the monitored ambient air quality data show compliance, insufficient data is available, or non-compliance with the ambient air quality standards, respectively. The CECP project site is located within the San Diego Air Basin (SDAB) and, as stated above, is under the jurisdiction of the San Diego Air Pollution Control District. This area is designated as nonattainment for both the federal

and state ozone standards and the state PM10 and PM2.5 standards. **AIR QUALITY Table 3** summarizes federal and state attainment status of criteria pollutants for the SDAB.

The project site is located in northwestern San Diego County, in the City of Carlsbad just west of the Interstate 5, one quarter mile east of Carlsbad Boulevard, just south of Aqua Hedionda Lagoon, and 4/10^{ths} of a mile north of Cannon Road.

The operating monitoring stations closest to the proposed project site with long-term records for ozone and NOx are the Camp Pendleton and Oceanside Mission Avenue monitoring stations, for CO and PM10/PM2.5 the Escondido East Valley Parkway monitoring station and for SOx the San Diego 12th Avenue and Beardsley Street monitoring stations. The coastal location of the Camp Pendleton, Oceanside and San Diego monitoring stations make them somewhat more representative of conditions in Carlsbad than the inland Escondido monitoring stations, which due to its inland valley location would be expected to have higher CO and PM10/PM2.5 concentrations than found in coastal Carlsbad.

AIR QUALITY Table 2
Federal and State Ambient Air Quality Standards

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

Source: ARB 2008a.

AIR QUALITY Table 3
Federal and State Attainment Status for the San Diego Air Basin

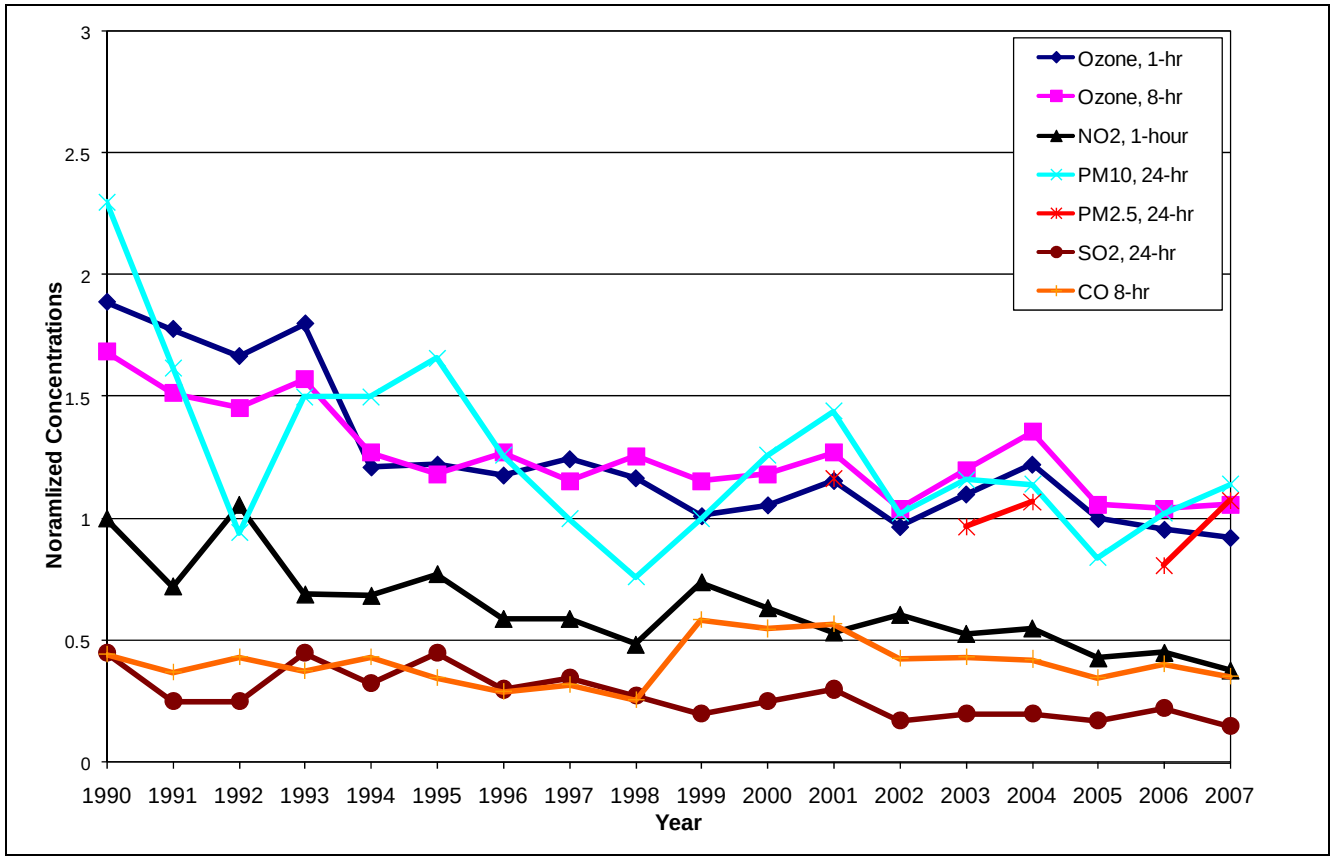
Pollutant	Attainment Status	
	Federal	State
Ozone	Former Subpart 1 Nonattainment (8-hr) [a]	Serious Nonattainment (1-hr)
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
PM10	Attainment	Nonattainment
PM2.5	Attainment	Nonattainment

Source: ARB 2008b, U.S. EPA 2008.

Note: a – The U.S. EPA is in the process of redesignating the San Diego Air Basin to moderate non-attainment.

AIR QUALITY Figure 1 summarizes the historical air quality data for the project location, recorded at representative air monitoring stations (1990-2007 for Ozone, PM10, CO, NO_2, SO_2; 1999-2007 for PM2.5). In **AIR QUALITY Figure 1**, the short term normalized concentrations are provided from 1990 to 2007. Normalized concentrations represent the ratio of the highest measured concentrations in a given year to the most-stringent applicable national or state ambient air quality standard. Therefore, normalized concentrations lower than one indicates that the measured concentrations were lower than the most-stringent ambient air quality standard.

AIR QUALITY Figure 1
Normalized Maximum Short-Term Historical Air Pollutant Concentrations



Source: ARB 2008c, SDAPCD 2008a.

A Normalized Concentration is the ratio of the highest measured concentration to the applicable most stringent air quality standard. For example, in 1999 the highest one-hour average ozone concentration measured at the Oceanside Mission Avenue station was 0.091 ppm. Since the most stringent ambient air quality standard is the state standard of 0.09 ppm, the 1999 normalized concentration is 0.091/0.09 = 1.011.

Following is a more in-depth discussion of ambient air quality conditions in the project area.

Ozone

In the presence of ultraviolet radiation, both nitrogen oxides (NOx) and volatile organic compounds (VOC) go through a number of complex chemical reactions to form ozone. **AIR QUALITY Table 4** summarizes the best representative ambient ozone data collected from the Oceanside Mission Avenue and Camp Pendleton monitoring stations.

The table includes the maximum one-hour and eight-hour ozone levels and the number of days above the state or national standards. Ozone formation is higher in spring, summer, and early fall and lower in the winter. The SDAB was classified as an attainment area for the previous federal 1-hour ozone standard (no longer applicable) and is classified as a basic nonattainment area for the federal 8-hour ozone standard. The SDAB is also classified as a serious nonattainment area for the state 1-hour ozone standard.

AIR QUALITY Table 4
Ozone Air Quality Summary, 1990-2007 (ppm)

Year	Days Above CAAQS 1-Hr	Month of Max. 1-Hr Avg.	Max. 1-Hr Avg.	Days Above NAAQS 8-Hr	Month of Max. 8-Hr Avg.	Max. 8-Hr Avg.
Oceanside - Mission Avenue						
1990	14	OCT	0.170	5	OCT	0.118
1991	14	MAY	0.160	8	MAY	0.106
1992	12	SEP	0.150	7	SEP	0.102
1993	7	SEP	0.162	5	SEP	0.110
1994	2	JUN	0.109	1	SEP	0.089
1995	5	SEP	0.110	0	NOV	0.083
1996	4	MAY	0.106	3	OCT	0.089
1997	6	OCT	0.112	0	OCT	0.081
1998	3	JUL	0.105	1	JUL	0.088
1999	0	APR	0.091	0	APR	0.081
2000	1	MAR	0.095	0	MAR	0.083
2001	1	SEP	0.104	1	SEP	0.089
Camp Pendleton						
2002	0	MAY	0.087	0	MAY	0.073
2003	4	OCT	0.099	0	OCT	0.084
2004	4	MAY	0.110	2	OCT	0.095
2005	0	AUG	0.090	0	APR	0.074
2006	0	SEP	0.086	0	FEB	0.073
2007	0	MAR	0.083	0	MAY	0.074

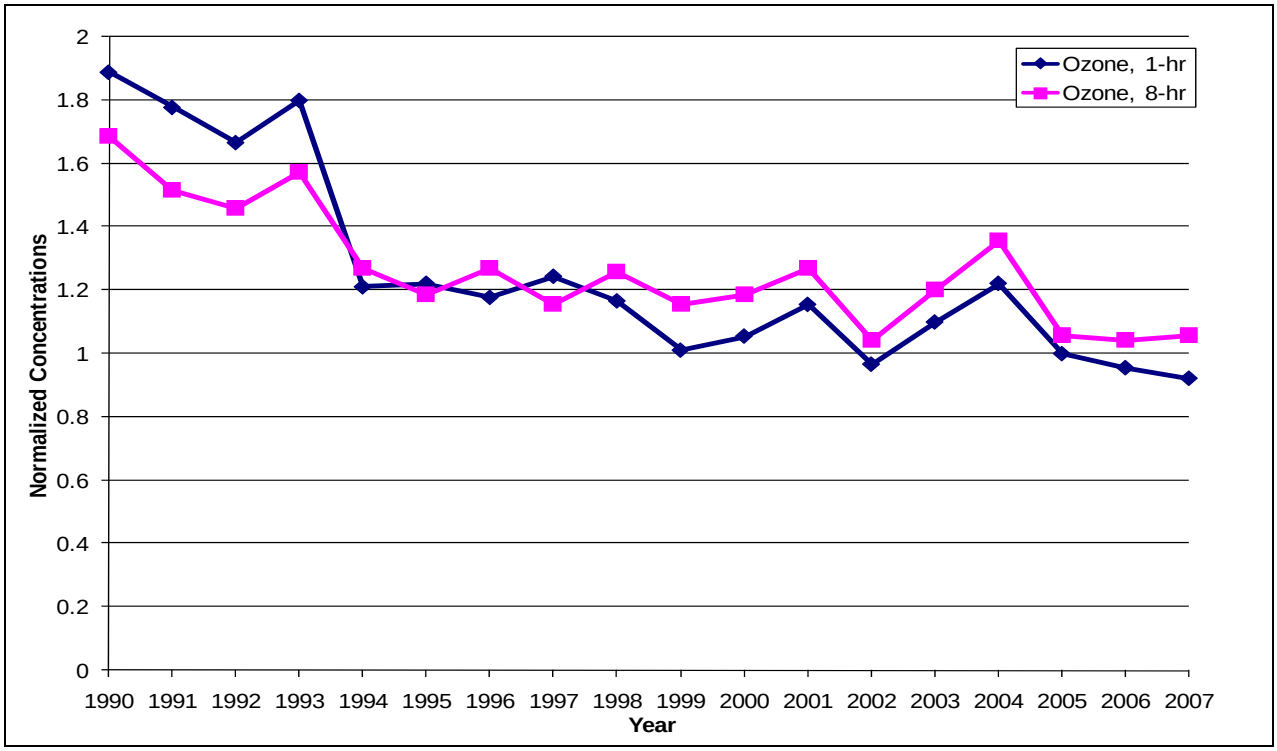
California Ambient Air Quality Standard (CAAQS): 1-Hr, 0.09 ppm, 8-Hr, 0.070 ppm
National Ambient Air Quality Standard (NAAQS): 8-Hr, 0.075 ppm, days above standard based on old standard of 0.080 ppm.

Source: ARB 2008c.

The yearly trends from 1990 to 2007 for the maximum one-hour and eight-hour ozone concentrations, referenced to the most stringent standard, and the number of days exceeding the California one-hour standard and the federal eight-hour standard for the Oceanside Mission Avenue (1990-2001) and Camp Pendleton (2002-2007) monitoring stations is shown in **AIR QUALITY Figure 2** and **Figure 3**, respectively.

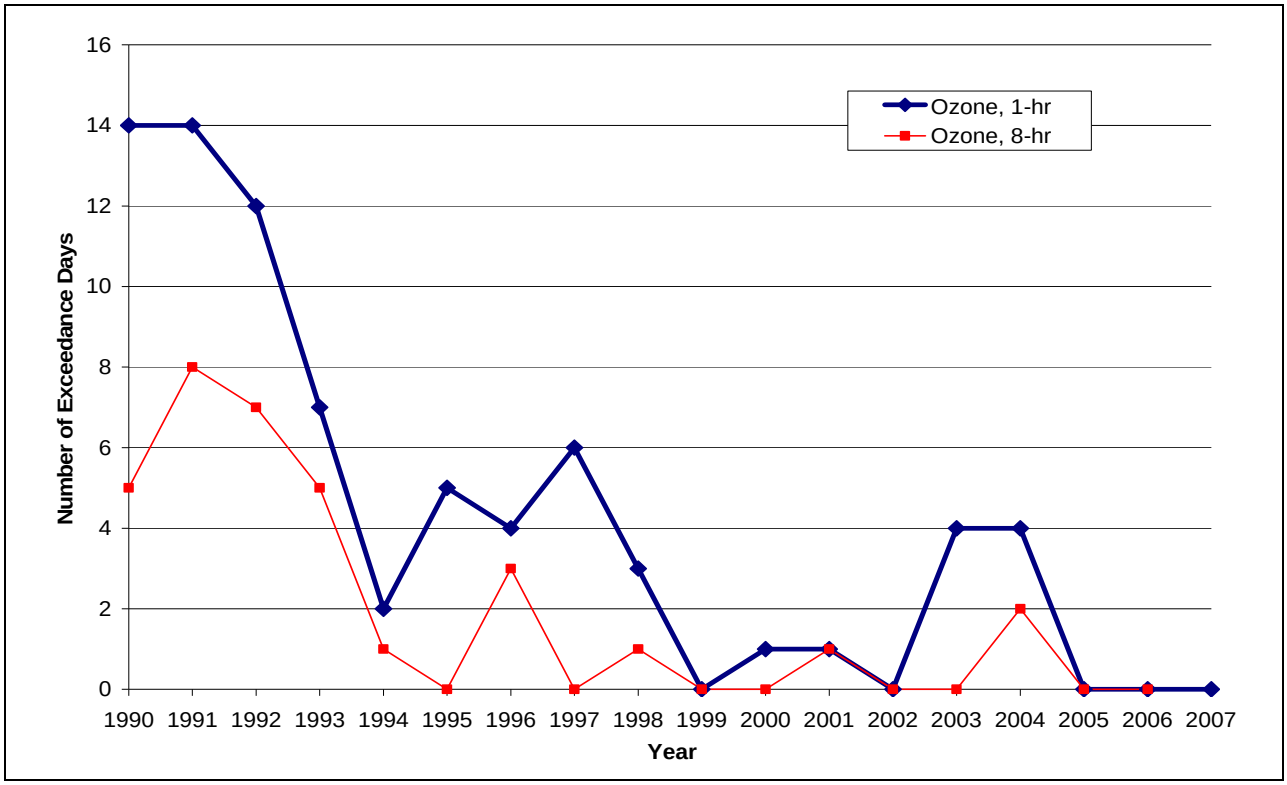
As these two figures show, the one-hour and eight-hour ozone concentrations were highest in 1990 and the number of exceedances was highest in 1990 or 1991. Maximum concentrations and the number of AAQS exceedances have declined significantly since 1990.

AIR QUALITY Figure 2
Normalized Ozone Air Quality Maximum Concentrations



Source: ARB 2008c.

AIR QUALITY Figure 3
Ozone – Number of Days Exceeding the Air Quality Standards



Source: ARB 2008c.

Respirable Particulate Matter (PM10)

As **AIR QUALITY Table 5** indicates, the representative monitoring stations annually experience occasional violations of the state 24-hour PM10 standard and continue to exceed the state annual PM10 standard. The SDAB is classified as an attainment area for the federal PM10 standard and as a nonattainment area for the state PM10 standards.

AIR QUALITY Table 5
PM10 Air Quality Summary, 1990-2007 ($\mu g/m^3$)

Year	Days * Above Daily CAAQS	Month of Max. Daily Avg.	Max. Daily Avg.	Annual Arithmetic Mean
Oceanside - Mission Avenue				
1990	35	NOV	115	32.8
1991	--	JAN	81	--
1992	0	SEP	47	28.7
1993	12	OCT	75	28.9
1994	16	JAN	75	29.1
1995	27	NOV	83	30.5
1996	6	JAN	63	25.6
1997	--	NOV	50	--
1998	0	AUG	38	22.1
Escondido – East Valley Parkway				
1999	0	DEC	50	29.7
2000	12	DEC	63	29.5
2001	12	JAN	72	30.6
2002	0	SEP	51	27
2003	31	DEC[a]	58[a]	32.7[a]
2004	6	JAN	57	27.3
2005	0	OCT	42	23.9
2006	6	DEC	51	24.2
2007	2	NOV[a]	57[a]	24[a]

California Ambient Air Quality Standard: 24-Hr, 50 $\mu g/m^3$; Annual Arithmetic, 20 $\mu g/m^3$
National Ambient Air Quality Standard: 24-Hr, 150 $\mu g/m^3$

* Days above the state standard (calculated), rounded to nearest whole day: PM10 is monitored approximately once every six days. This value is a mathematical estimate of how many days the PM10 concentrations would have been greater than the ambient air quality standard had each day been monitored.

[a] Excludes 2003 and 2007 firestorm events

Source: ARB 2008c, SDAPCD 2008a.

-- Data not available

PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SOx and VOC from turbines, and ammonia from NOx control equipment, given the right meteorological conditions, can form particulate matter

in the form of nitrates (NO_3), sulfates (SO_4), and organic particles. These pollutants are known as secondary particulates, because they are not directly emitted, but are formed through complex chemical reactions in the atmosphere.

PM 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 wintertime are a significant portion of the total PM10, and are likely even a higher contributor to particulate matter of less than 2.5 microns (PM2.5). The nitrate ion is only a portion of the PM nitrate, which can be in the form of ammonium nitrate (ammonium plus nitrate ions) and some as sodium nitrate. If the ammonium and the sodium ions associated with the nitrate ion are taken into consideration, PM nitrate contributions to the total PM are even more significant.

As shown in **AIR QUALITY Table 5**, the highest PM10 concentrations are generally measured in the fall and winter when there are frequent low-level inversions. During the wintertime high PM10 episodes, the contribution of ground level releases to ambient PM10 concentrations is disproportionately high.

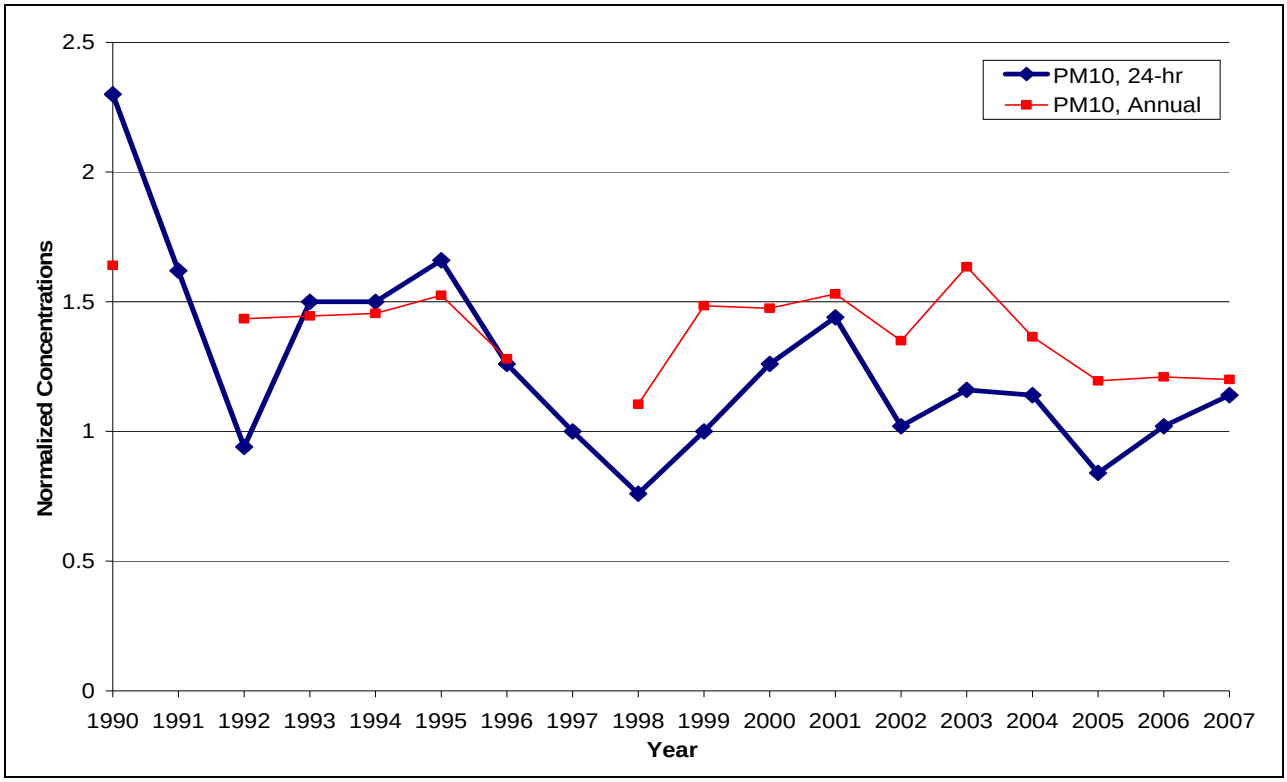
The 1990 to 2007 yearly trends for the maximum 24-hour PM10 and Annual Arithmetic Mean PM10, referenced to the most stringent standard, and the number of days exceeding the California 24-hour PM10 standard for the Oceanside (1990-1998) and Escondido (1999-2007) monitoring stations is shown in **AIR QUALITY Figure 4** and **Figure 5**, respectively.

As the two figures show, there is an overall gradual downward trend for PM10 concentrations and number of violations of the California 24-hour standard since 1990; however, there has been little progress since 1996.

Fine Particulate Matter (PM2.5)

The SDAB is classified as nonattainment for the state fine particulate matter (PM2.5) standard and is an attainment area for the federal standards. As shown in **AIR QUALITY Table 6**, the highest PM2.5 concentrations are generally measured in the winter. The relative contribution of wood-smoke particles to the PM2.5 concentrations may be even higher than its relative contribution to PM10 concentrations, considering that most of the wood-smoke particles are smaller than 2.5 microns.

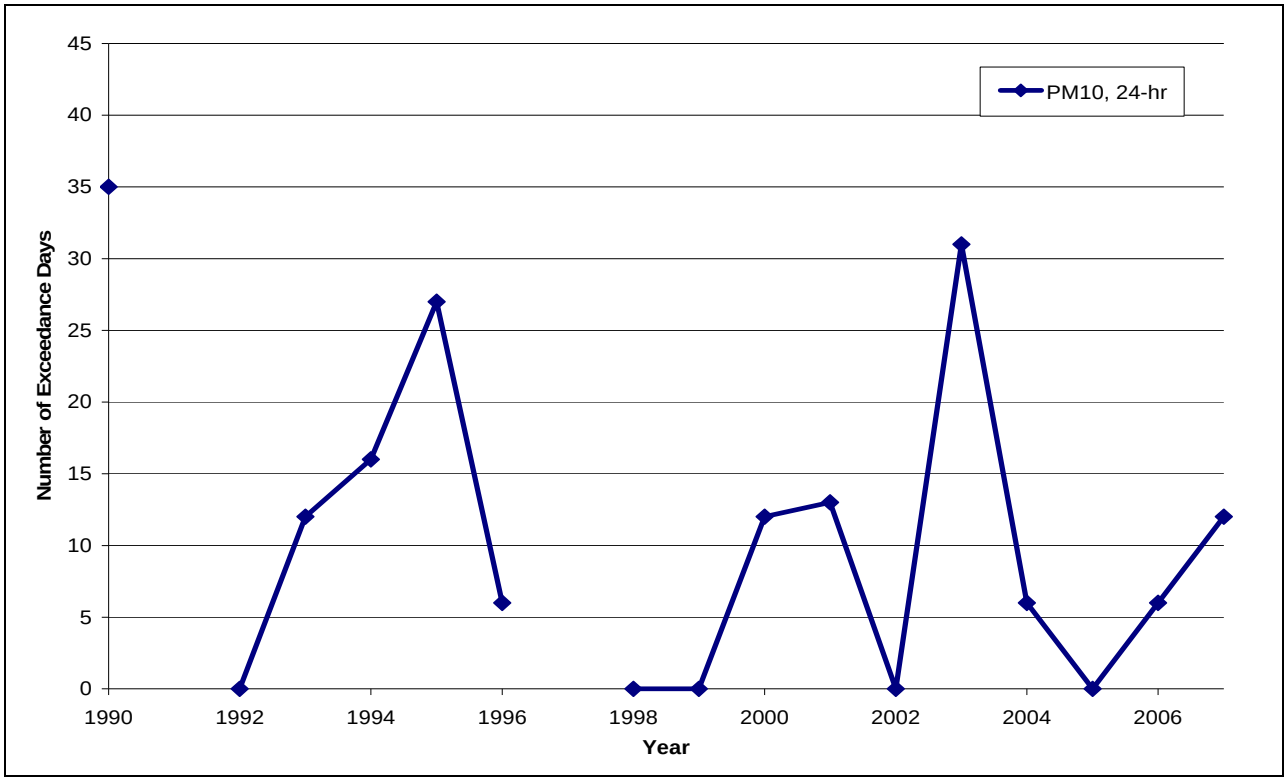
AIR QUALITY Figure 4
Normalized PM10 Air Quality Maximum Concentrations



Source: ARB 2008c, SDAPCD 2008a.

AIR QUALITY Figure 5

PM10 24-Hour – Number of Days Exceeding the Air Quality Standard



Source: ARB 2008c, SDAPCD 2008a.

As **AIR QUALITY Table 6** indicates, the 24-hour (3-year average 98th percentile) PM2.5 concentration levels have been declining from 1999-2007, but were still above the NAAQS of 35 $\mu g/m^3$ in 2007 at the Escondido monitoring station. The annual arithmetic means also appear to have been declining from 1999-2007, but continues to be as high as the CAAQS of 12 $\mu g/m^3$ as of 2007.

AIR QUALITY Table 6
PM2.5 Air Quality Summary, 1999-2007 ($\mu g/m^3$)

Year	National Maximum Daily	Month of Maximum Daily	98th Percentile Maximum Daily	State Annual Average	National Annual Average
Escondido – East Valley Parkway					
1999	64.3	OCT	--	--	18.0
2000	65.9	DEC	--	--	15.8
2001	60.0	JAN	40.8	--	17.5
2002	53.6	JAN	--	--	16.0
2003	37.9 [a]	OCT	33.9	14.2	14.2
2004	67.3	JAN	37.4	14.1	14.1
2005	43.1	JAN	--	--	--
2006	40.6	DEC	28.3	11.5	11.5
2007	36[a]	DEC	37.7	12	12

California Ambient Air Quality Standard: Annual Arithmetic Mean, 12 $\mu g/m^3$
National Ambient Air Quality Standard: 24-Hr Avg. Conc., 35 $\mu g/m^3$ (based on 98 percent of the daily concentrations, average over three years); Annual Arithmetic Mean, 15 $\mu g/m^3$
[a] Excludes 2003 and 2007 firestorm events

Source: ARB 2008c, SDAPCD 2008a.

Carbon Monoxide (CO)

The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground level in what is known as the stable boundary layer. These conditions occur frequently in the wintertime, late in the afternoon, persist during the night and may extend one or two hours after sunrise. Since mobile sources (motor vehicles) are the main cause of CO, ambient concentrations of CO are highly dependent on motor vehicle activity. In fact, the peak CO concentrations occur during the rush hour traffic in the mornings and afternoons. CO concentrations in San Diego County and the rest of the state have declined significantly due to two state-wide programs: 1) the 1992 wintertime oxygenated gasoline program, and 2) Phases I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also contributed to the decline in CO levels in the state. Today, all the areas of California are in attainment with the CO ambient air quality standards.

AIR QUALITY Table 7 shows the maximum one-hour and eight-hour CO concentrations monitored in Oceanside and Escondido, where Escondido would be expected to have higher CO concentrations than Carlsbad due to its inland valley

location. CO is considered a local pollutant, as it is found in high concentrations only near the source of emission. Automobiles and other mobile sources are the principal sources of the CO emissions. High levels of CO emissions can also be generated from fireplaces and wood-burning stoves. According to the data recorded at the Oceanside and Escondido air monitoring stations, there has been only one exceedance of the Ambient Air Quality Standards since 1990 and that exceedance was due to the 2003 firestorm (see **AIR QUALITY Figure 1 and Table 7**).

AIR QUALITY Table 7
CO Air Quality Summary, 1990-2007 (ppm)

Year	Month of Max. 8-Hr Average	Maximum 1-Hr Average	Maximum 8-Hr Average
Oceanside - Mission Avenue			
1990	JAN	6.0	4.00
1991	DEC	7.0	3.33
1992	JAN	7.0	3.88
1993	DEC	5.3	3.40
1994	DEC	5.2	3.91
1995	JAN	4.4	3.13
1996	JAN	4.0	2.60
1997	JAN	6.1	2.88
1998	DEC	3.2	2.31
Escondido – East Valley Parkway			
1999	DEC	9.9	5.26
2000	NOV	9.3	4.93
2001	JAN	8.5	5.11
2002	JAN	8.5	3.85
2003	OCT	8.9[a]	3.90[a]
2004	JAN	6.3	3.81
2005	JAN	5.9	3.10
2006	DEC	5.7	3.61
2007	DEC	5.2	3.19

California Ambient Air Quality Standard: 1-Hr, 20 ppm; 8-Hr, 9.0 ppm
National Ambient Air Quality Standard: 1-Hr, 35 ppm; 8-Hr, 9 ppm
[a] Excludes 2003 firestorm event where maximum 1-Hr and 8-Hr CO concentrations were 12.7 and 10.6 ppm, respectively.

Source: ARB 2006, ARB 2008c, SDAPCD 2008a.

Nitrogen Dioxide (NO_2)

As shown in **AIR QUALITY Table 8,** the maximum one-hour and annual concentrations of NO_2 at the Oceanside and Camp Pendleton monitoring stations are lower than the California and National Ambient Air Quality Standards. Approximately 75 to 90 percent of the NOx emitted from combustion sources is Nitric Oxide (NO), while the balance is NO_2. NO is oxidized in the atmosphere to NO_2 by oxygen and ozone. In the summer, the conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions (atmospheric unstable conditions) generally disperse pollutants, preventing the accumulation of NO_2 to levels approaching the California one-hour ambient air quality standard. Additionally NO_2 concentrations are reduced during

summer daylight conditions through consumption in the photochemical reaction that creates ozone. The formation of NO_2 in the presence of ozone is according to the following reaction:

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

As shown in **AIR QUALITY Table 8,** the maximum one-hour and annual concentrations of NO_2 at the Oceanside and Camp Pendleton monitoring stations typically occur in winter or fall.

AIR QUALITY Table 8
NO_2 Air Quality Summary, 1990-2007 (ppm)

Year	Month of Max. 1-Hr Average	Maximum 1-Hr Average	Annual Average
Oceanside – Mission Avenue			
1990	JAN	0.180	0.023
1991	FEB	0.130	0.024
1992	JAN	0.190	0.024
1993	FEB	0.124	0.020
1994	JAN	0.123	0.020
1995	NOV	0.139	0.019
1996	JAN	0.106	0.017
1997	OCT	0.106	0.018
1998	DEC	0.087	0.016
1999	JAN	0.133	0.019
2000	JAN	0.114	0.017
2001	FEB	0.096	0.016
Camp Pendleton			
2002	FEB	0.109	0.013
2003	JAN	0.095	0.012
2004	JAN	0.099	0.012
2005	JAN	0.077	0.012
2006	MAY	0.081	0.011
2007	JAN	0.068	0.010
California 1-Hr Ambient Air Quality Standard: 0.18 ppm California Annual Arithmetic Mean Ambient Air Quality Standard: 0.03 ppm National Annual Arithmetic Mean Ambient Air Quality Standard: 0.053 ppm			

Source: ARB 2008c.

Sulfur Dioxide (SO_2)

Sulfur dioxide is typically emitted as a result of the combustion of a fuel containing sulfur. Natural gas contains very little sulfur and consequently has very low SO_2 emissions when combusted. By contrast, fuels high in sulfur content, such as coal, emit very large amounts of SO_2 when combusted.

Sources of SO_2 emissions within the SDAB come from every economic sector and include a wide variety of fuels: gaseous, liquid and solid. The SDAB is designated

attainment for all the SO_2 state and federal ambient air quality standards. **AIR QUALITY Table 9** shows the historical one-hour, 24-hour and annual average SO_2 concentrations collected from the Oceanside Mission Avenue, San Diego 12th Avenue, and Beardsley Street monitoring stations. As **AIR QUALITY Table 9** shows, concentrations of SO_2 are far below the state and federal SO_2 ambient air quality standards.

AIR QUALITY Table 9
SO_2 Air Quality Summary, 1990-2007 (ppm)

Year	Maximum 1-Hr Avg.	Month of Max. 24-Hr Avg.	Maximum 24-Hr Avg.	Annual Average
Oceanside – Mission Avenue				
1990	0.020	DEC	0.018	0.001
1991	0.020	NOV	0.010	0.001
1992	0.020	SEP	0.010	0.001
San Diego - 12th Avenue [a]				
1993	0.047	JAN	0.018	0.003
1994	0.069	JUN	0.013	0.003
1995	0.063	AUG	0.018	0.003
1996	0.048	APR	0.012	0.003
1997	0.052	MAY	0.014	0.003
1998	0.040	JUL	0.011	0.003
1999	0.039	AUG	0.008	0.002
2000	0.038	SEP	0.010	0.004
2001	0.052	AUG	0.012	0.003
2002	0.028	SEP	0.007	0.003
2003	0.036	JAN	0.008	0.004
2004	0.042	SEP	0.008	0.004
2005	0.040	APR	0.007	0.003
San Diego – Beardsley Street				
2006	0.034	FEB	0.009	0.004
2007	0.018	OCT	0.006	0.003

California Ambient Air Quality Standard: 1-Hr, 0.25 ppm; 24-Hr, 0.04 ppm
National Ambient Air Quality Standard: 3-Hr, 0.5 ppm; 24-Hr, 0.14 ppm; Annual, 0.030 ppm
[a] 2005 is a mixture of San Diego 12th Avenue and Beardsley Street.

Source: ARB 2006, ARB 2008c, SDAPCD 2008a.

Visibility

Visibility in the region of the project site depends upon the area's natural relative humidity and the intensity of both particulate and gaseous pollution in the atmosphere. The most straightforward characterization of visibility is probably the visual range (the greatest distance that a large dark object can be seen). However, in order to characterize visibility over a range of distances, it is more common to analyze the changes in visibility in terms of the change in light-extinction that occurs over each additional kilometer of distance (1/km). In the case of a greater light-extinction, the visual range would decrease.

The SDAB is currently designated as unclassified for visibility reducing particles.

Summary

In summary, staff recommends the background ambient air concentrations in **AIR QUALITY Table 10** for use in the modeling and impacts analysis. The maximum criteria pollutant concentrations from the past three years of available data collected at the monitoring stations within San Diego County are used to determine the recommended background values.

AIR QUALITY Table 10
Staff Recommended Background Concentrations (µg/m^3)

Pollutant	Averaging Time	Recommended Background	Limiting Standard	Percent of Standard
NO_2	1 hour	152.6	339	45%
	Annual	22.8	57	40%
PM10	24 hour	57	50	114%
	Annual	24.2	20	121%
PM2.5	24 hour	37.7	35	108%
	Annual	12	12	100%
CO	1 hour	6,785	23,000	30%
	8 hour	4,011	10,000	40%
SO_2	1 hour	94.3	655	16%
	3 hour	84.9	1,300	7%
	24 hour	23.6	105	23%
	Annual	10.7	80	14%

Source: ARB 2006, ARB 2008c, SDAPCD 2008a, and Energy Commission Staff Analysis

Where possible, staff prefers that the recommended background concentrations come from nearby monitoring stations with similar characteristics. For this project the Camp Pendleton monitoring station (ozone and NO_2) is located reasonably close to the project site, in the Camp Pendleton Marine Base approximately 6.3 miles north northwest of the project site. The Escondido (CO, PM10, and PM2.5) and San Diego (SO_2) monitoring stations are located further from the site, but considering the inland valley location of Escondido and the more industrialized area of San Diego these two locations should provide conservatively high background concentrations for Carlsbad.

The background concentrations for PM10 and PM2.5 are at or above the most restrictive existing ambient air quality standards, while the background concentrations for the other pollutants are all well below the most restrictive existing ambient air quality standards.

The pollutant modeling analysis was limited to the pollutants listed above in **AIR QUALITY Table 10**; therefore, recommended background concentrations were not determined for the other criteria pollutants (ozone, lead, visibility, etc.).

PROJECT DESCRIPTION AND EMISSIONS

The applicant has proposed to develop the CECP on a 23-acre site, within the 95-acre Encina Power Station site. This 23-acre site currently contains three unused fuel-oil storage tanks that previously serviced the existing Encina Power Station boilers. The project would consist of two Siemens Rapid Response SGT6-5000F gas turbines operating in combined cycle mode and a 246 brake horsepower (bhp) diesel fire pump engine. The project would employ air cooling and would not include any other stationary emission sources. The existing Encina Power Station (EPS) boilers Units 1 through 3 would be removed from service after the new power facilities are installed and begin commercial operation.

The project would maximize the use of existing linear lines; therefore, no offsite construction is necessary for transmission, gas supply, or sewer lines for this project. The proposed project includes demolition of fuel-oil storage tanks 5, 6, and 7 along with any resulting soil remediation, and the construction of a new 230-kV switchyard. An ocean-water purification system would be constructed to assure sufficient quantities of water. The maximum daily intake of ocean water for purification purposes would range between 604,500 gallons per day (gpd) without power augmentation (PAG) and 1.22 million gallons per day (mgd) with PAG operating 8 hours per day, plus additional ocean water for mixing at the outfall for a maximum 4.32 mgd. The project would discharge industrial wastewater either through the existing EPS ocean-water discharge system or through the City's existing sanitary/industrial wastewater sewer system,

The project site is located in the City of Carlsbad just west of the I-5, one quarter mile east of Carlsbad Boulevard, just south of Aqua Hedionda Lagoon, and 4/10ths of a mile north of Cannon Road. The site location is in a man-made depression or pit that was constructed as secondary containment for the fuel tanks. The general area around the site has mixed use with heavy industrial use (the Encina Power Station), light industrial use, commercial use, residential, and schools; as well as, recreational use of the Pacific Ocean beaches, the Agua Hedionda Lagoon, and Cannon Park.

The nearest residence is located approximately 0.44 miles to the northeast of the site, with other residences 0.49 miles and 0.51 miles to the northwest and southwest of the site. The nearest school, Jefferson Elementary, is located approximately 0.69 miles north northwest of the site.

CONSTRUCTION

Construction of the CECP would consist of the following onsite activities: 1) demolition of the existing oil tanks; 2) removal of oil contaminated soils; 3) site preparation, grading and reclaim water pipeline installation; 3) reconstruction of the berm; 4) power plant construction.

The total construction period is 25 months. During the construction periods, most of heavier construction activities would occur between 7 am and 7 pm, 9 hours per day, 5 days per week. However, there would be times when additional hours of construction may be necessary to make up for construction delays due to weather or other

unforeseen events. Some activities would be continuous 24 hours per day, 7 days per week, during some construction periods and during startup and commission of the units.

Construction laydown and construction worker parking area for this project would occupy approximately 10 acres of property within the existing Encina Power Station. An existing railroad line, which would be available for delivery of materials and heavy equipment, is located immediately on the west side of the project site. Materials and other equipment would also be delivered by truck, accessed from Cannon Road.

Fugitive dust emissions during the construction of the project would result from dust entrained during demolition, site preparation and grading/excavation activities, on-site and offsite travel on paved and unpaved surfaces, and aggregate and soil loading and unloading operations, as well as wind erosion of areas disturbed during construction activities. The largest fugitive dust emissions are often generated during site preparation activities, where work such as clearing, grading, excavation of footings and foundations, and backfilling operations occur. These types of activities require the use of large earth moving equipment, which generate combustion emissions, along with creating fugitive dust emissions. Fugitive dust emissions resulting from onsite soil disturbances, such as dozing and grading, and from onsite and offsite traffic also were estimated.

Combustion emissions during the construction of the project result from exhaust sources, including diesel construction equipment used for site preparation, water trucks used to control dust emissions, cranes, diesel-powered welding machines, electric generators, air compressors, water pumps, diesel trucks, and trains used for deliveries, and automobiles and trucks used by workers to commute to and from the construction site.

Below construction emissions are based on the 25 month construction schedule. The applicant's estimates for the maximum daily emissions during construction period are shown in **AIR QUALITY Table 11**.

AIR QUALITY Table 11
Maximum Daily Emissions During Construction, lbs/day

Activity	NOx	CO	VOC	SOx	PM10	PM2.5
On-Site						
Construction Equipment	274.90	150.27	25.19	0.30	11.45	11.45
Fugitive Dust	--	--	--	--	30.77	6.14
Off-site						
Worker Travel, Truck, Rail Deliveries	218.78	379.15	42.62	0.40	9.45	9.45
Total Maximum Daily Emissions	493.67	529.42	67.82	0.71	51.66	27.04

Source: SR 2008h, Table 5.1E1-19

The peak annual on-site and off-site construction equipment exhaust and fugitive emissions, which for NOx occur during months 5 through 16 of the 25 month construction schedule, are summarized in **AIR QUALITY Table 12**.

AIR QUALITY Table 12
Peak Annual Emissions During Construction, tons/year

Activity	NOx	CO	VOC	SOx	PM10	PM2.5
On-Site						
Construction Equipment	16.94	13.34	1.68	0.02	0.71	0.71
Fugitive Dust	--	--	--	--	2.47	0.45
Off-site						
Worker Travel, Truck, Rail Deliveries	9.69	31.61	3.26	0.03	0.49	0.49
Total Peak Annual Emissions	26.63	44.95	4.94	0.05	3.68	1.65

Source: SR 2008h, Table 5.1E1-19

The onsite emissions shown in **AIR QUALITY Tables 11** and **12** are somewhat lower than the emissions, from an earlier applicant emission estimate, that were used to model the air quality impacts from construction.

INITIAL COMMISSIONING

The initial commissioning of a power plant refers to the time between the completion of construction and the reliable production of electricity for sale on the market. For most power plants, normal operating emission limits usually do not apply during the initial commissioning activities.

The commissioning activities for the two turbines (known as Units 6 and 7) would be completed simultaneously. Commissioning is estimated to last for 58 days for Unit 6 and 61 days for Unit 7. Starting with Unit 6 first, each of the two gas turbines would undergo sequential test operation with increasing load levels and successive application of the air pollution control systems. After completing the commissioning period, the new units are expected to be available for commercial operation. During the commissioning period, the existing boilers Units 1, 2, and 3 at the Encina Power Station would be available for operation; however, these boilers would not be operated simultaneously with a new CTG undergoing a commissioning test.

AIR QUALITY TABLE 13 presents the applicant's estimated emissions during the initial commissioning period (CECP 2007a). The project would have a total of 49 commissioning activities, which are summarized in the 18 test categories as shown in the table. The emission rate for SO_2 is not expected to be higher during the commissioning period than during normal operation.

AIR QUALITY Table 13
CECP Initial Commissioning Activities, Duration, and Emissions (lbs/hr/turbine)

Commissioning Activity	Duration (hr)	NOx	CO	VOC	PM
GT Testing @ 0% load	8	47.0	3812.6	163.8	11.6
GT Testing @ 40% load	8	200.1	2210.4	84.6	12.8
Steam Blow/HRSG Tuning	12	146.3	3642.7	80.8	12.0
Steam Blow	24	83.9	762.3	59.4	9.3
Establish vacuum/HRSG,BOP Tuning GT Load Test & Bypass Valve Tubing	64	14.9	56.8	8.5	8.6
GT Load Test & Bypass Valve Tubing /Safety Valve Testing	12	18.5	70.2	7.7	8.8
GT Base Load/Commissioning of NH_3 system GT Load Test & Bypass Valve Tubing	24	21.7	71.0	8.1	9.8
Bypass Operation/STG Initial Roll & Trip Test	10	18.2	86.9	11.3	8.9
Bypass Operation/STG Load Test	16	14.9	56.8	8.5	8.6
GT on Bypass/STG Load Test	16	19.8	54.2	6.6	9.5
Combine Cycle Testing/Drift Test (1)	24	16.1	25.6	3.9	9.0
Combine Cycle Testing/Drift Test (2)	24	15.8	15.6	3.0	8.9
Emissions Tuning/Drift Test Pre-performance Testing/Drift Test	60	21.7	71.0	8.1	9.8
RATA/Pre-performance Testing/Source Testing	15	20.2	57.6	6.9	9.5
Pre-performance Testing/Source Testing (1)	14	20.6	61.4	7.2	9.6
Pre-performance Testing/Source Testing (2)	12	21.7	71.0	8.1	9.8
Performance Testing	48	17.9	37.4	5.0	9.2
CALISO Certification	24	21.7	71.0	8.1	9.8

Source: CECP 2007a, Appendix 5.1 B, Table 5.1B-9
Note: BOP = Balance of Plant.

The initial commissioning short-term modeling analysis presented in the Impacts section uses these worst-case emission values.

AIR QUALITY Table 14 shows the summary of annual initial commissioning emissions per turbine.

AIR QUALITY Table 14
CECP Initial Commissioning Emissions per Turbine, tons

	NOx	CO	VOC	PM
Per Gas Turbine	6.24	65.17	3.48	1.96
Total	12.48	130.34	6.96	3.92

Source: CECP 2007a, Appendix 5.1 B, Table 5.1B-9 and FDOC (SDAPCD 2009)

OPERATIONAL PHASE

Equipment Description

The CECP facility would consist of two power blocks, with the following major components, providing a total nominal generating capacity of 540.4 MW net: (CECP 2007a, SR 2008h):

- Two Siemens SGT6-PAC5000F Combustion Turbine generators (CTG) equipped with Dry Low-NOx (DLN) combustion system, inlet air filters, steam power augmentation, and inlet air evaporative coolers;

- Two Heat Recovery Steam Generators (HRSG);
- Each HRSG would be equipped with a selective catalytic reduction (SCR) system with 19 percent aqueous ammonia injection to further reduce NOx emissions, and an oxidation catalyst to reduce CO emissions;
- Two condensing steam turbine generators (STG);
- Two air-cooled fin-fan coolers;
- Two 139-foot tall, 21.3-foot diameter exhaust stacks;
- A continuous emission monitoring (CEM) system installed on each stack would record concentrations of NOx, CO, and oxygen in the flue gas;
- A 246 brake horsepower (bhp) emergency fire pump engine.

Facility Operation

The facility would be capable of operating 7 days a week, 24 hours per day, but is being permitted to a maximum emission equivalent of 4,100 hours per year. This is equivalent to an annual capacity factor of approximately 47 percent. The applicant expects that the new facility would be operated primarily as an intermediate duty unit (aka mid-merit) on a daily basis, especially during summer months when there are peak demands. Annual non-emergency operation of the emergency fire pump engine would be limited to 50 hours per year of engine testing.

The applicant is not able to determine the exact operational schedule for CECP since the operation profile would change depending on the variable demand in the service area. The Energy Commission 2007 Integrated Energy Policy Report (IEPR) forecasts an increasing demand for electricity in the San Diego region (CEC 2007f). In addition, the South Bay Power plant in the service region city of Chula Vista is expected to retire, perhaps as early as the end of 2009. Therefore, overall power generation at the Encina Power Station is likely to increase, rather than decrease, over the next several years.

CECP operations would require a 14 person workforce including operators on rotating shifts and maintenance technicians during the standard 8-hour work day. However, CECP operation would not require new employees because this 14 person workforce would be provided by the 50 person workforce which operates the existing Encina Power Station.

Emission Controls

The exclusive use of pipeline-quality natural gas, a relatively clean-burning fuel, would limit the formation of VOC, PM10, and SO_2 emissions. Natural gas contains very little noncombustible gas or solid residues and a small amount of reduced sulfur compounds, including mercaptan. A dry low-NOx (DLN) combustor and post-combustion NOx control in the form of a selective catalytic reduction (SCR) system would be provided for each power block to control NOx concentrations in the exhaust gas. The SCR system would use 19 percent aqueous ammonia to reduce NOx emissions to no greater than 2.0 parts per million by volume, dry (ppmvd) adjusted to 15 percent oxygen from the gas turbines/SCR systems. Ammonia slip would be limited to 5 ppmvd at 15 percent oxygen on a dry basis. Staged combustion of a pre-mixed fuel/air charge would reduce CO and

VOC emissions. An oxidizing catalytic converter would be used to further reduce the CO concentration in the exhaust gas emitted to the atmosphere to 2.0 ppmvd adjusted to 15 percent oxygen. VOC emissions would also be limited to 2.0 ppmvd adjusted to 15 percent oxygen. Particulate and SOx emissions would be controlled using natural gas as the sole fuel for the CTG (CECP 2007a). The emergency fire pump engine emissions would be controlled by the use of an engine meeting U.S.EPA/ARB Tier 2 engine emission standards, or Tier 3 if available, and using California low sulfur (15 ppm sulfur) diesel fuel.

Two 139-foot tall, 21.3-foot diameter stacks would release the CTGs exhaust gas into the atmosphere. A continuous emission monitoring (CEM) system would be installed on the CTG stack to monitor flue gas flow rate, NOx and CO concentration levels, and percentage of oxygen in the flue gas to assure adherence with the proposed emission limits. The CEM system would generate reports of emissions data in accordance with permit requirements and send alarm signals to the control room in plant when the level of emissions approaches or exceeds pre-selected limits.

Project Operating Emissions

Air emissions would be generated from operating the two CTGs. The maximum hourly normal operating emission rates for the CTGs are provided in **AIR QUALITY Table 15.** The maximum hourly normal operating emission rates reflect the cold ambient base load operating case.

AIR QUALITY Table 15[a]
Maximum Normal Pollutant Emission Rates, lb/hr

Operating Unit	NOx	CO	VOC	SOx[b]	PM10
Unit 6	15.1	9.2	4.0	4.4	9.50
Unit 7	15.1	9.2	4.0	4.4	9.50
Total Maximum Hourly Emissions	30.2	18.4	8.0	8.8	19.00

Source: CECP 2007a, Appendix 5.1B, Table 5.1B-2B and FDOC (SDAPCD 2009)
[a] Emission rates shown reflect the highest value at any operating load. The full load average annual hourly emission rate values for NOx, CO, VOC and SOx are somewhat lower than these maximum values. For NOx, CO, and VOC emission levels exclude startups and shutdowns.
[b] SO_2 emissions are based on worst case natural gas sulfur content of 0.75 grains/100 dry standard cubic feet. Actual likely long-term worst-case sulfur content is less than 0.25 grains/100 dry standard cubic feet.

Expected maximum emission rates during startup and shutdown events are summarized in **AIR QUALITY Table 16**. Hourly startup emissions rates reflect 22 minutes of elevated emissions followed by 38 minutes of normal operating emission levels. During shutdown, the emissions rates reflect 7 minutes of elevated emission levels preceded by 53 minutes of normal operating emissions. The applicant also expects that there could be periodic cases which would have both startup and shutdown events within an hour. This case represents the worst case hourly emissions, reflecting 29 minutes of higher emission levels and 31 minutes of normal operating emission levels; however, it is expected that this would occur very infrequently. PM10 and SO_2 emissions are not shown in the **AIR QUALITY Table 16**, since the emissions for these pollutants are not estimated to be higher or lower during startup and shutdown events than during normal operation.

AIR QUALITY Table 16
Maximum Short-Term Event Emissions, lbs/hr, per gas turbine

Startup/Shutdown	NOx	CO	VOC
Startup	69.2	545	15.5
Shutdown	47	286	8.2
Startup/Shutdown	86	814	19.8

Source: FDOC (SDAPCD 2009)

The derivation of these short-term emission limits includes a safety factor of 2 for short-term emission limits (CECP 2007a, Appendix 5.1B, Table 5.1B-7). A safety factor of 1.5 is used for annual emissions estimates of startup and shutdown.

The FDOC issued by the San Diego Air Pollution Control District includes a number of permit conditions that allow for operation during tuning (adjusting or tuning the combustor cans) circumstances (Conditions **AQ-13**), at low load (Conditions **AQ-20**) and operation of the turbine units at NOx concentrations greater than BACT (Conditions **AQ-32**, **33** and **34**). After additional review and discussion with the District, staff is satisfied that these conditions, even though they allow higher stack NO_2 concentrations, do not allow emission rates (lbs/hour) that are higher than the bounding conditions for emissions presented in **Air Quality Tables 13** and **16** so the impact analysis for initial commission and start-up operations does provide the bounding worst-case.

The applicant also requested an allowance for increased NOx 1-hour average emissions up 12 ppm (or six time higher than normally allowed) for up to 15 hours per year during transient conditions that could have occurred in several defined ways, including: rapid turbine load changes initiated under Automatic Generation Control, rapid turbine load changes due to automatic safety or equipment protection control systems activation, the first two hours after inactivation of the gas turbine inlet air cooler, or other events resulting from technological limitations agreed to by the District. The District researched this request and determined that there was insufficient documentation to support the need for this additional exception to the 2.0 ppm NOx limit, but the District does allow for the 2.0 ppm NOx, the 2.0 ppm CO, and the 1.5 ppm VOC concentration limits to be based on a 3-hour average during transient conditions rather than a one-hour average to cover minor potential emission spikes during transient conditions (**AQ-28**, **29**, and **30**). Staff supports the District's finding regarding transient conditions operation.

AIR QUALITY Table 17 summarizes the maximum (worst-case) estimated daily emissions for CECP. Maximum daily emissions for turbines are based on 6 hours of startup, 6 hours of shutdown, and 12 hours of normal operation.

AIR QUALITY Table 17
CECP Worst-Case Hourly and Daily Emissions

	Hours	NOx	CO	VOC	SOx[a]	PM10	NH_3
Startup (lbs/hr)	6	69.2	545	15.5	4.40	9.50	14.01
Shutdown (lbs/hr)	6	47	286	8.2	4.40	9.50	14.01
Normal Operation (lbs/hr)	12	15.1	9.2	4.0	4.40	9.50	14.01
Emergency Fire Pump (lbs/hr)	1	2.08	0.24	0.05	0.00	0.035	0.00
Maximum (Single gas turbine, lbs/day)		877	5102	190	106	228	336
Maximum (Two gas turbines, lbs/day)		1,754	10205	380	211	456	672
Maximum (New Equipment, lbs/day)		1,756	10205	380	211	456	672

Source: CECP 2007a, Appendix 5.1B, Table 5.1B-2B and FDOC (SDAPCD 2009)
[a] SO_2 annual emissions are based on SDG&E tariff basis of 0.75 grains/100 dry standard cubic feet.

Maximum annual emissions for turbines are based on 300 hours of startup and 300 hours of shutdown and 3500 hours of normal operation at annual average base conditions. The maximum annual emissions are shown in **AIR QUALITY Table 18**. The emissions from the emergency fire pump are estimated based on 50 hours of operation annually. The emission rates for annual worst-case emissions calculation are slightly lower than those for daily worst-case emissions calculation, as the applicant has assumed somewhat different annual average and hourly/daily worst case startup and shutdown emissions; and the operating condition assumed for the annual emissions calculations is the average ambient base load case, rather than the cold ambient base load case that was used to calculate the maximum potential daily emissions. The annual emissions listed in **AIR QUALITY Table 18** are the proposed annual emission limits for the CECP.

AIR QUALITY Table 18
CECP Worst-Case Hourly and Annual Emissions

	Hours	NOx	CO	VOC	SOx[a]	PM10	NH_3
Startup (lbs/hr)	300	51.88	409.25	15.5	1.37	9.5	13.08
Shutdown (lbs/hr)	300	35.05	214.71	8.2	1.37	9.5	13.08
Normal Operation (lbs/hr)	3500	14.13	8.6	3.7	1.37	9.5	13.08
Emergency Fire Pump (lbs/hr)	50	2.08	0.24	0.05	0.0	0.035	0.0
Maximum (Single gas turbine, ton/yr)		37.77	108.65	10.03	2.81	19.48	26.81
Maximum (Two gas turbines, ton/yr)		75.54	217.30	20.05	5.61	38.95	53.62
Maximum (New Equipment, ton/yr)		75.59	217.31	20.05	5.61	38.95	53.62

Source: CECP 2007a, Appendix 5.1B, Table 5.1B-4 and FDOC (SDAPCD 2009)
[a] For the purposes of determining annual average SOx emissions a natural gas sulfur content of 0.25 grains/100 dry standard cubic feet is used. The FDOC indicates an annual permitted emission rate of 8.43 tons per year per turbine based on a sulfur content of 0.75 grains/100 dry standard cubic feet.

AIR QUALITY Table 19 summarizes the expected applicant's estimate for the maximum annual emissions for the CECP, the existing Encina Power Plant Unit 1-3 annual emissions baseline[1], and the expected maximum annual incremental project emission increase.

AIR QUALITY Table 19
CECP Incremental Annual Emissions

	Pollutant (tons/year)				
Emission Source	**NOx[a]**	**CO[b]**	**VOC[c]**	**SOx**	**PM10[d]**
CECP Expected Maximum Annual Emissions	72.11[a]	217.3	20.1	5.6	39.0
Encina Power Plant Units 1-3 Emissions Baseline	32.21	268.80	15.3	6.15	31.5
Net Emissions Increase	39.9	-51.51[b]	4.8	-0.6	7.5

Source: CECP 2007a, SR 2008k, and FDOC (SDAPCD 2009).
[a] The applicant has taken a reduced facility-wide NOx emission limit to ensure that emissions were limited below PSD permitting thresholds.
[b] This represents normal operating years. For the initial commissioning year the annual CO emissions would be permitted to 339.9 tons, which for that one year of initial commissioning would result in an emission increase in CO of 71.0 tons.
[c] This represents normal operating years. For the initial commissioning year the annual VOC emissions would be permitted to 23.7 tons, which for that one year of initial commissioning would result in an emission increase in VOC of 8.4 tons compared to the average annual potential VOC increase of 4.8 tons.
[d] The total emission increase for PM2.5 is 7.6 tons.

[1] Baseline as determined by SDAPCD staff through correspondence with the Encina project owner using an average of 2002 to 2006 emissions, correcting 2002 and 2003 NOx emissions for Rule 69 compliance. The specific annual corrected emissions baseline for Encina boiler units 1 to 3, in tons per year, determined by SDAPCD staff are as follows (SDAPCD 2008c):

	2002	2003	2004	2005	2006	Average
NOx	39.99	27.7	46	31.73	16.17	32.21
CO	494.59	344.03	266.73	144.25	94.43	268.80
VOC	16.18	14.83	22.14	15.41	8.11	15.33
SOx	9.53	12.51	2.41	3.69	2.59	6.15
PM10	34.97	27.66	45.28	33.58	15.97	31.49

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses three kinds of impacts: construction, operation, and cumulative effects. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation. Cumulative impacts analysis assesses the impacts that result from the proposed project's incremental effect viewed over time, together with other closely related past, present, and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project. (Pub. Resources Code § 21083; Cal. Code Regs., tit. 14, §§ 15064(h), 15065(c), 15130, and 15355.) Additionally, cumulative impacts are assessed in terms of conformance with the District's attainment or maintenance plans.

METHOD AND THRESHOLDS FOR DETERMINING SIGNIFICANCE

Staff used two main significance criteria in evaluating this project. First, all project emissions of nonattainment criteria pollutants and their precursors (NOx, VOC, PM10 and SO_2) are considered significant cumulative impacts that must be mitigated. Second, any AAQS violation or any contribution to any AAQS violation caused by any project emissions is considered to be significant and must be mitigated. For construction emissions, the mitigation that is considered is limited to controlling both construction equipment tailpipe emissions and fugitive dust emissions to the maximum extent feasible. For operating emissions, the mitigation includes both feasible emission controls (BACT) and the use of emission reduction credits to offset emissions of nonattainment criteria pollutants and their precursors.

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

DIRECT/CUMULATIVE IMPACTS AND MITIGATION

While the emissions are the actual mass of pollutants emitted from the project, the impacts are the concentration of pollutants from the project that reach the ground level. When emissions are expelled at a high temperature and velocity through the relatively tall stack, the pollutants would be significantly diluted by the time they reach ground level. The emissions from the proposed project are analyzed through the use of air dispersion models to determine the probable impacts at ground level.

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

The applicant has used EPA-approved screening (SCREEN3) and refined (ISCST3 and AERMOD version 07026) air dispersion models to estimate the direct impacts of the project's NOx, PM10, CO, and SOx emissions resulting from project construction and operation.

Staff revised the background concentrations provided by the applicant, replacing them with the available highest ambient background concentrations as show in **AIR QUALITY Table 10**. Staff added the modeled impacts to these background concentrations, then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or would contribute to an existing violation.

The inputs for the air dispersion models include stack information (exhaust flow rate, temperature, and stack dimensions), specific turbine emission data and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the Camp Pendleton Station during 2003 through 2005, which is the closest complete meteorological data source to the project site, and is meteorological data both compiled by and approved for use by the SDAPCD. Additionally, the applicant obtained hourly ozone and NO_2 ambient data from the Camp Pendleton monitoring station for 2003 to 2005 from the District that was used in a more refined NO_2 impact modeling analysis using the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM) options that are available with AERMOD.

Construction Impacts and Mitigation

The following section discusses the project's short-term direct and cumulative construction ambient air quality impacts, as estimated by the applicant and revised by staff, and provides a discussion of appropriate mitigation. Staff reviewed the construction emissions estimates and air dispersion modeling procedures and requested the applicant provided revisions to both analyses as part of project discovery. Staff considers the revised analyses to provide an adequately conservative prediction of project construction impacts.

Construction Impact Analysis

The applicant used both the EPA guideline Industrial Source Complex Short Term (ISCST) model and ARMS/EPA Regulatory Model (AERMOD) model to estimate ambient impacts. The emission sources for the construction site were grouped into three categories: exhaust emissions, construction dust emissions, and windblown dust emissions. The exhaust and construction dust emissions were modeled as volume sources. The windblown dust emissions were modeled as area sources. For the volume sources, the vertical dimension was set to 6 meters, and the horizontal dimension was set based on the width of the construction area.

For the determination of one-hour average construction NOx concentrations the Ozone Limiting Method (OLM) was used to determine worst-case near field NO_2 impacts. The NOx emissions from internal combustion sources, such as diesel engines or gas turbines, are primarily in the form of nitric oxide (NO) rather than NO_2. The NO converts into NO_2 in the atmosphere, primarily through the reaction with ambient ozone, and NOx

OLM assumes full conversion of stack NO emission with the available ambient ozone. The NOx OLM method used assumed an initial NO_2/NOx ratio of 0.1 for diesel equipment. Actual monitored hourly background ozone and NO_2 concentration data (2003 to 2005 data that corresponds with the meteorological files) were used by this modeling method to calculate maximum potential NO to NO_2 conversion plus actual corresponding hourly NO_2 background to determine the maximum hourly NO_2 impacts. For the computing of annual average construction NOx concentrations, the Ambient Ratio Method (ARM) with the national default value of 0.75 for the annual average NO_2/NOx ratio was used by the applicant.

To determine the construction impacts on short-term ambient standards (i.e. 1-hour through 24 hours) the worst-case daily on-site construction emission levels were modeled[2]. For pollutants with annual average ambient standards, the annual on-site emissions levels were added to a conservatively estimated "background" of existing emissions to determine the cumulative effect. For the modeling analysis, it is assumed that all of the equipment would operate from 7 am to 4 pm for the short-term impact modeling (24 hours or less) and also only work on weekdays for the annual impact modeling. **AIR QUALITY Table 20** provides the results of this modeling analysis.

AIR QUALITY Table 20
CECP Maximum Onsite Construction Impacts, (μg/m^3)

Pollutant	Averaging Period	Project Impact (μg/m^3)	Background (μg/m^3) [a]	Total Impact (μg/m^3)	Limiting Standard (μg/m^3)	Type of Standard	Percent of Standard
NO_2	1 hour [b]	244	30	274	339	CAAQS	81%
	annual [c]	9	22.8	31.8	57	CAAQS	56%
PM10	24 hour	17	57	74	50	CAAQS	148%
	annual	2.4	24.2	26.6	20	CAAQS	133%
PM2.5	24 hour	7.1	37.7	44.8	35	NAAQS	128%
	annual	0.9	12	12.9	12	CAAQS	108%
CO	1 hour	1,343	6,785	8,128	23,000	CAAQS	35%
	8 hour	168	4,011	4,179	10,000	CAAQS	42%
SO_2	1 hour	2.7	94.3	97.0	655	CAAQS	15%
	3 hour	0.9	84.9	85.8	1,300	NAAQS	7%
	24 hour	0.1	23.6	23.7	105	CAAQS	23%
	annual	0.01	10.7	10.7	80	NAAQS	14%

Source: SR 2008a
[a] Background values, other than the 1-hour NO_2 value, have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 10**.
[b] The NOx modeling analysis was performed using the ozone limiting method and matched both hourly background and hourly NO2 background concentrations for the ten highest modeled concentrations of each of the three modeled years (2003 to 2005) to determine a maximum hourly concentration.
[c] The annual modeling results were adjusted using the U.S. EPA default annual average Ambient Ratio Method (ARM) NOx ratio of 0.75.

As can be seen from the modeling results provided in **AIR QUALITY Table 20**, the construction impacts have the potential to worsen the existing violations of the PM10 and PM2.5 ambient air quality standards and are, therefore, potentially significant and

[2] The modeled emissions are based on an earlier construction equipment emission estimate that was somewhat higher than the latest emission estimate shown in **AIR QUALITY Tables 11** and **12**.

require all feasible mitigation. The applicant's construction modeling analysis indicates that the maximum NO_2, CO and SO_2 impacts would remain below the CAAQS and NAAQS. The NOx and VOC emissions from construction, when considering their potential secondary ozone formation added to the existing ozone "background", have the potential to contribute to existing exceedances of the ozone standard and are therefore potentially significant and staff recommends all feasible mitigation.

The maximum NO_2 project impacts are shown to be much higher than the background concentration in **AIR QUALITY Table 20** because the maximum modeled NO_2 impact, including ozone conversion of NO to NO_2 plus the actual hour NO_2 background, happened to occur during an hour with a low ambient NO_2 concentration.

The maximum construction impacts occur at the property line. The maximum residential and nearest school receptor[3] impacts of gaseous air pollutants (NOx, CO, and SOx) are lower than the maximum impact levels at the property line shown in **AIR QUALITY Table 20.** The maximum property line impacts are well below the associated ambient air quality standards for these pollutants. The maximum modeled residential and school receptor PM10 and PM2.5 concentrations, not including background, were determined to be as follows:

	Residential Receptor	School Receptor[4]
PM10 24-hour	6.25 µg/m^3	<5.36 µg/m^3
PM10 annual	0.082 µg/m^3	<0.017 µg/m^3
PM2.5 24-hour	2.60 µg/m^3	<2.22 µg/m^3
PM2.5 annual	0.031 µg/m^3	<0.006 µg/m^3

Staff is recommending all feasible mitigation measures to reduce construction emissions and associated impacts.

Construction Mitigation

Staff recommends that construction emission impacts be mitigated to the greatest feasible extent including all required measures from the District's rules and regulations, as well as other measures considered necessary by staff to fully mitigate the construction emissions. The District recently promulgated a fugitive dust control rule (Rule 55), that will become effective on December 24, 2009. The standard recommended Energy Commission fugitive dust control conditions would require control measures that would be as strict as or stricter than the requirements of new District Rule 55.

Applicant's Proposed Mitigation

The applicant proposed the following construction emission mitigation measures (CECP 2007a, Appendix 5.1E):

[3] The nearest residence is located approximately 0.44 miles to the northeast of the site, with other residences 0.49 miles and 0.51 miles to the northwest and southwest of the site. The nearest school, Jefferson Elementary, is located approximately 0.69 miles north northwest of the site.

[4] The impacts shown are for a point approximately 500 meters south of the school as the receptor grid did not extend far enough north to include the school. The more distant school would have lower impacts.

- Unpaved roads and disturbed areas in the project construction site will be watered as frequently as necessary to prevent fugitive dust plumes. The frequency of watering can be reduced or eliminated during periods of precipitation.
- The vehicle speed limit will be 15 miles per hour within the construction site.
- The construction site entrances shall be posted with visible speed limit signs.
- Construction equipment vehicle tires will be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.
- Gravel ramps of at least 20 feet in length will be provided at the tire washing/cleaning station.
- Unpaved exits from the construction site will be graveled or treated to prevent track out to public roadways.
- Construction vehicles will enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the Compliance Project Manager.
- Construction areas adjacent to any paved roadway will be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent run-off to roadways.
- Paved roads within the construction site will be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation or dirt and debris.
- 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 runoff from the construction site is visible on public roadways.
- Soil storage piles and disturbed areas that remain inactive for longer than 10 days will be covered or treated with appropriate dust suppressant compounds.
- Vehicles used to transport solid bulk material on public roadways and having the potential to cause visible emissions will be provided with a cover, or the materials will be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.
- Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and / or vegetation) will 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.

The applicant's construction emissions estimates as presented in **AIR QUALITY Tables 11** to **12,** and as used to determine the construction modeling impact results shown in **AIR QUALITY Table 18** assume the use of these fugitive emission control measures, as well as, the use of construction equipment that meets U.S. EPA/ARB Tier 2 nonroad diesel engine standards.

Adequacy of Proposed Mitigation

The applicant's proposed mitigation measures are very similar to those generally proposed by staff, so they are generally considered adequate with minor modifications to incorporate the latest staff recommendations and site specific concerns.

Staff Proposed Mitigation

Staff recommends construction PM10 and NOx emission mitigation measures as articulated in Conditions of Certification **AQ-SC1** through **AQ-SC5** that include the mitigation measures proposed by the applicant, with additional construction PM10 emission mitigation measures, revised construction equipment mitigation measures, and an addition to mitigate the potential for dust plume impacts on the adjacent I-5 freeway to assure maximum feasible fugitive dust control performance, construction equipment exhaust emissions control, and compliance enforcement mechanisms.

Staff recommends **AQ-SC1** to require the applicant to have an on-site construction mitigation manager who would be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the construction mitigation program would be provided in the monthly construction compliance report that is required in staff's recommended Condition of Certification **AQ-SC2**.

Staff incorporated and augmented the applicant's proposed fugitive dust mitigation and recommends that the fugitive dust mitigation measures be formalized in Condition of Certification **AQ-SC3**.

Staff recommends Condition of Certification **AQ-SC4** to limit the potential offsite impacts from visible dust emissions, to respond to situations when the control measures required by **AQ-SC3** are not working effectively to control fugitive dust from leaving the construction site area, and to respond to any potential dust plume impacts to the adjacent I-5 freeway. Specific attention to mitigating visible dust impacts on the I-5 freeway are considered necessary due to its proximity, high traffic volumes, and its predominate downwind direction from the site.

Staff recommends Condition of Certification **AQ-SC5**, integrating and augmenting the applicant's assumed construction equipment mitigation as reasonable, to mitigate the PM and NOx emissions from the large diesel-fueled construction equipment. Implementation of this mitigation measure would provide additional primary and secondary PM mitigation to supplement the recommended fugitive dust mitigation measures. This condition requires the use of EPA/ARB Tier 2 engine compliant equipment for equipment over 100 horsepower where available, a good faith effort to find and use available EPA/ARB Tier 3 engine compliant equipment over 100 horsepower, and also includes equipment idle time restrictions and engine maintenance provisions. The Tier 2 standards include engine emission standards for NOx plus non-methane hydrocarbons, CO, and PM emissions; while the Tier 3 standards further reduce the NOx plus non-methane hydrocarbons emissions. The Tier 2 and Tier 3 standards became effective for engine/equipment model years 2001 to 2003 and

models years 2006 to 2007, respectively, for engines between 100 and 750 horsepower.

Implementation of staff's recommended construction emission mitigation measures contained in the recommended Conditions of Certification would substantially reduce fugitive dust and tailpipe emissions during construction, particularly during the peak construction grading period, and reduce the potential for significant air quality impacts from this temporary emission source.

Operation Impacts and Mitigation

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

The applicant performed direct impact modeling analyses, including operations, startup and shutdown, fumigation, and an initial commissioning impact analysis.

Operational Modeling Analysis

Initial screening modeling was performed to determine the worst case short-term ambient and operating condition. Turbine emission rates were first calculated for seventeen operating conditions:

- Three nominal load points, low (60%), mid, and base (100%).
- Four different ambient conditions, cold, mild, average, and hot.
- Operating base load with the inlet evaporative coolers (not cold ambient) and with steam power augmentation (not cold or mild ambient).

These conditions were then modeled to determine the worst case short-term ambient and operating conditions and the assumptions to be used for the stack parameters in the startup/initial commissioning worst-case short term impact modeling analysis.

A refined modeling analysis was performed to estimate off-site criteria pollutant impacts from operational emissions of the proposed project. Refined modeling was performed in two phases: coarse grid modeling and fine grid modeling. Preliminary modeling was performed with the coarse grid to identify the areas of maximum concentration. Fine grids were used to refine the location of the maximum concentration.

The applicant used the AERMOD model to estimate ambient impacts. For the determination of NOx concentrations under all operating conditions the Plume Volume Molar Ratio Method (PVMRM) option was used. The NOx emissions from internal combustion sources, such as gas turbines, are primarily in the form of NO rather than NO_2. The NO converts into NO_2 in the atmosphere, primarily through the reaction with ambient ozone, and PVMRM mixes the plume with an assumed ozone concentration to determine the actual availability of ozone in the mixed plume and then assumes full conversion of stack NO emission with that available amount of ozone. The PVMRM method used by the applicant assumed an initial NO_2/NOx ratio of 0.1 and a final equilibrium ratio of 0.9. Actual monitored hourly background ozone and NO_2

concentration data (2003 to 2005 data that corresponds with the meteorological files) were used by this modeling method to calculate maximum potential NO to NO_2 conversion.

The applicant's predicted maximum concentrations of the directly emitted (not secondarily formed) pollutants for the CECP project under normal steady-state operating conditions of the CTGs are summarized in **AIR QUALITY Table 21.**

AIR QUALITY Table 21
CECP Normal Gas Turbine Operating Impacts – Both CTGs, (µg/m^3)

Pollutant	Averaging Period	Project Impact (µg/m^3)	Background (µg/m^3) [a]	Total Impact (µg/m^3)	Limiting Standard (µg/m^3)	Type of Standard	Percent of Standard
NO_2	1 hour	13.3	152.6	165.9	339	CAAQS	49%
	annual	0.1	22.8	22.9	57	CAAQS	40%
PM10	24 hour	1.2	57	58.2	50	CAAQS	117%
	annual	0.1	24.2	24.3	20	CAAQS	122%
PM2.5	24 hour	1.2	37.7	38.9	35	NAAQS	111%
	annual	0.1	12	12.1	12	CAAQS	101%
CO	1 hour	9.0	6,785	6,794	23,000	CAAQS	30%
	8 hour	1.9	4,011	4,013	10,000	CAAQS	40%
SO_2 [b]	1 hour	4.3	94.3	98.6	655	CAAQS	15%
	3 hour	2.0	84.9	86.9	1,300	NAAQS	7%
	24 hour	0.4	23.6	24.0	105	CAAQS	23%
	annual	0.0	10.7	10.7	80	NAAQS	13%

Source: SR 2008f
[a] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 10**.

The applicant's predicted maximum concentrations of the directly emitted pollutants for the CECP project, including the fire pump engine along with the CTGs operating under normal steady-state conditions are summarized in **AIR QUALITY Table 22.**

AIR QUALITY Table 22
CECP Normal Facility Operating Impacts – CTGs and Fire Pump Engine, (µg/m^3)

Pollutant	Averaging Period	Project Impact (µg/m^3)	Background (µg/m^3) [a]	Total Impact (µg/m^3)	Limiting Standard (µg/m^3)	Type of Standard	Percent of Standard
NO_2	1 hour	108.0	152.6	260.6	339	CAAQS	77%
	annual	0.1	22.8	22.9	57	CAAQS	40%
PM10	24 hour	1.2	57	58.2	50	CAAQS	117%
	annual	0.1	24.2	24.3	20	CAAQS	122%
PM2.5	24 hour	1.2	37.7	38.9	35	NAAQS	111%
	annual	0.1	12	12.1	12	CAAQS	101%
CO	1 hour	18.2	6,785	6,803	23,000	CAAQS	30%
	8 hour	1.9	4,011	4,013	10,000	CAAQS	40%
SO_2 [b]	1 hour	4.3	94.3	98.6	655	CAAQS	15%
	3 hour	2.0	84.9	86.9	1,300	NAAQS	7%
	24 hour	0.4	23.6	24.0	105	CAAQS	23%
	annual	0.0	10.7	10.7	80	NAAQS	13%

Source: SR 2008f
[a] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 10**.

As the difference in **AIR QUALITY Tables 21** and **22** shows, the fire pump engine, when testing has a higher short-term near-field impact potential for NOx and CO than the CTGs. This is due both to its lower height and lower exhaust buoyancy that enhances downwash and higher near-field ground level impacts and the more concentrated NOx and CO emissions in the fire pump engine exhaust. The applicant's modeling results indicate that the project's normal operational impacts would not create violations of NO_2, SO_2 or CO standards, but could further exacerbate violations of the PM10 and PM2.5 standards. In light of the existing PM10 and PM2.5 non-attainment status for the project site area, staff considers the modeled impacts to be significant and, therefore, we recommend mitigation.

Startup/Shutdown Event Modeling Impact Analysis

NOx and CO emissions are usually higher during startup and shutdown events than during steady state operation as the gas turbine emissions are higher during the short periods of unsteady state operation for startup and shutdown and the SCR and oxidation catalyst control systems are not functioning at their peak efficiency immediately upon startup or during shutdown. The applicant used the AERMOD model (version 07026) to determine the maximum short term NOx and CO emission impacts during simultaneous startup/shutdown of two gas turbines. The applicant's predicted maximum short-term NOx and CO concentrations from startup/shutdown events are summarized in **AIR QUALITY Table 23.**

AIR QUALITY Table 23
CECP Startup/Shutdown Impacts, (µg/m^3)

Pollutant	Averaging Period	Project Impact (µg/m^3)	Background (µg/m^3) [a]	Total Impact (µg/m^3)	Limiting Standard (µg/m^3)	Type of Standard	Percent of Standard
NO_2	1 hour	80.4	152.6	233.0	339	CAAQS	69%
CO	1 hour	1,134	6,785	7,919	23,000	CAAQS	34%
	8 hour	236	4,011	4,247	10,000	CAAQS	43%

Source: SR 2008f
[a] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 10**.

The applicant's modeling results indicate that the project's maximum startup/shutdown emission impacts would not cause any new significant ambient impacts associated with NOx and CO.

Fumigation Modeling Impact Analysis

There is the potential that higher short-term concentrations may occur during fumigation conditions. During the early morning hours before sunrise, the air is usually very stable. During such stable meteorological conditions, emissions from elevated stacks rise through this stable layer and are dispersed. When the sun first rises, the air at ground level is heated, resulting in a vertical (both rising and sinking air) mixing of air for a few hundred feet or so. Emissions from a stack that enter this vertically mixed layer of air would also be vertically mixed, bringing some of those emissions down to the ground level. Later in the day, as the sun continues to heat the ground, this vertical mixing layer becomes higher and higher, and the emissions plume becomes better dispersed. The early morning pollution event, called fumigation, usually lasts approximately 30 to 90 minutes.

Fumigation conditions are short-duration events and are generally only compared to one-hour standards. Two types of fumigation are analyzed using the SCREEN3 model: inversion breakup and shoreline. Inversion breakup fumigation occurs under low-wind conditions when a rising morning mixing height caps a stack (i.e., is at or right above the stack height) limiting plume rise and mixing which fumigates the air below. Shoreline fumigation occurs near a large water body shoreline when a roughness boundary causes turbulent dispersion to be much more enhanced near the ground, fumigating air below. The applicant modeled seventeen different operating cases to determine the maximum fumigation impacts from the CTGs. All of the pollutants/averaging periods showed maximums under hot ambient full load with steam power augmentation, except for the PM10/PM2.4 impacts which showed a maximum under the hot ambient low load (60 percent) operating condition. The results of the analysis are shown in **AIR QUALITY TABLE 24**.

AIR QUALITY Table 24
Maximum CECP Fumigation Impacts, (µg/m^3)

Pollutant	Averaging Period	Project Impact (µg/m^3)	Background (µg/m^3) [a]	Total Impact (µg/m^3)	Limiting Standard (µg/m^3)	Type of Standard	Percent of Standard
Inversion Breakup Fumigation							
NO_2	1 hour	2.6	152.6	155.2	339	CAAQS	46%
PM10	24 hour	0.9	57	57.9	50	CAAQS	116%
PM2.5	24 hour	0.9	37.7	38.6	35	NAAQS	110%
CO	1 hour	1.6	6,785	6,787	23,000	CAAQS	30%
	8 hour	1.0	4,011	4,012	10,000	CAAQS	40%
SO_2 [b]	1 hour	0.8	94.3	95.1	655	CAAQS	15%
	3 hour	0.6	84.9	85.5	1,300	NAAQS	7%
	24 hour	0.3	23.6	23.9	105	CAAQS	23%
Shoreline Fumigation							
NO_2	1 hour	18.5	152.6	171.1	339	CAAQS	50%
PM10	24 hour	1.7	57	58.7	50	CAAQS	117%
PM2.5	24 hour	1.7	37.7	39.4	35	NAAQS	113%
CO	1 hour	11.3	6,785	6,796	23,000	CAAQS	30%
	8 hour	3.5	4,011	4,014	10,000	CAAQS	40%
SO_2 [b]	1 hour	5.4	94.3	99.7	655	CAAQS	15%
	3 hour	4.8	84.9	89.7	1,300	NAAQS	7%
	24 hour	0.5	23.6	24.1	105	CAAQS	23%

Source: SR 2008f
[a] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 10**.

Maximum inversion breakup fumigation impacts for the turbines are lower than normal operating impacts predicted by AERMOD and were predicted to occur about 24.5 kilometers from the site (19.5 kilometers for PM10/PM2.5). The impacts under inversion fumigation conditions were found to above the maximum concentrations calculated under normal CTG operations (see **AIR QUALITY Table 21**), and the maximum impacts were found to occur approximately 2.0 kilometers from the site (1.3 kilometers for PM10/PM2.5).

Initial Commissioning Short-Term Modeling Impact Analysis

The applicant presented forty nine initial commissioning activities that would occur prior to meeting normal emission limits. The worst case conditions for the short-term NOx and CO impacts occur prior to the installation of the oxidation and SCR catalysts. The emissions for all cases and the worst-case are provided in **AIR QUALITY Tables 13 and 14**.

The applicant expects that there would be a staggered commissioning schedule for the project, therefore, the two CTGs would not undergo commissioning simultaneously. Consequently, analysis of commissioning impacts shown in **AIR QUALITY Table 25** is based on one CTG undergoing the worst case commissioning activity and the second CTG undergoing a normal operating startup/shutdown hour (see **AIR QUALITY Table 16**). The SO_2 and PM10 emissions and ambient air quality impacts are not forecast to be higher during initial commissioning or startup/shutdown events than they are under normal operation.

Air Quality Table 25
Maximum CECP Initial Commissioning Impacts

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$) [a]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Type of Standard	Percent of Standard
NO_2	1 hour	127.5	152.6	280.1	339	CAAQS	83%
CO	1 hour	3,228	6,785	10,013	23,000	CAAQS	44%
CO	8 hour	676	4,011	4,687	10,000	CAAQS	47%

Source: SR 2008f
[a] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 10**.

The applicant's impact analysis indicates that the project's maximum initial commissioning emission impacts are below the most stringent ambient air quality standards for NO_2 and CO.

Chemically Reactive Pollutant Impacts

Ozone Impacts

The project's gaseous emissions of NOx, SO_2, VOC, and ammonia can contribute to the formation of secondary pollutants: ozone and PM10/PM2.5.

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

PM2.5 Impacts

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

in this case would not necessarily lead to increases in ambient PM2.5 concentrations. In the case of an ammonia poor environment, there is insufficient ammonia to establish a balance and thus additional ammonia would tend to increase PM2.5 concentrations.

The San Diego Air Basin has not undergone the rigorous secondary particulate studies that have been performed in other areas of California, such as the San Joaquin Valley, that have more serious fine particulate pollution problems. However, the available chemical characterization data shows that the annual ammonium nitrate and ammonium sulfate fine particulate concentrations in El Cajon and San Diego range from approximately 50 and 60 percent of the state annual ambient standard (ARB 2005). Because of the known relationship of NOx and SOx emissions to PM2.5 formation, it can be said that the emissions of NOx and SOx from the CECP do have the potential (if left unmitigated) to contribute to higher PM2.5 levels in the region.

Additionally, there would certainly be some secondary particulate conversion from the ammonia emitted from the CECP project; however, there is currently no regulatory model that can predict the conversion rate. Therefore, it is recommended that ammonia emissions be limited to the extent feasible, while ensuring that the selective catalytic reduction unit maintains NOx emissions below the required controlled concentration limit of 2 ppm.

Impact Summary

The applicant is proposing to mitigate the project's NOx, VOC, SO_2, and PM10 emissions through the use of BACT and limit the ammonia slip emissions to 5 ppm. The applicant also proposes to fully offset the project's permitted NOx net emission increase as required by the District, and staff is recommending additional mitigation to fully mitigate the permitted net emission increase for all of the criteria ozone and particulate precursor criteria pollutants. The ammonia slip concentration level matches other recently licensed large combined cycle projects in California. With the applicant proposed and staff recommended emission offset mitigation and ammonia slip limit, it is staff's belief that the project would not cause significant secondary pollutant impacts.

Operations Mitigation

Applicant's Proposed Mitigation

Emission Controls

As discussed in the project description section, the applicant proposes to employ dry lo-NOx burners, SCR with ammonia injection, CO catalyst, and operate exclusively on pipeline quality natural gas to limit turbine emission levels. The AFC (CECP 2007a) and the FDOC (SDAPCD 2009) provide the following BACT emission limits, each for the two CTGs:

- NOx: 2.0 ppmvd at 15 percent O_2 (one-hour average, excluding startup/shutdown) and 15.1 lb/hr
- CO: 2.0 ppmvd at 15 percent O_2 (one-hour rolling average, excluding startup/shutdown) and 9.2 lb/hr

- VOC: 1.5 ppmvd at 15 percent O_2 (one-hour rolling average, excluding startup/shutdown) and 4.0 lb/hr
- PM10: 9.5 lb/hr
- SO_2: 4.4 lb/hr with fuel sulfur content of 0.75 grains/100 scf
- NH_3: 5 ppmvd at 15 percent O_2 and 13.08 lb/hr

The District's FDOC conditions include provisions to allow the NOx and CO emissions to meet 2.0 ppmvd with a three hour averaging period during transient load conditions and VOC emissions to meet 1.5 ppmvd with a three hour averaging period during transient load conditions, as well as, allowing higher NOx emissions during low load and tuning periods (see Conditions of Certification **AQ-28**, **29**, **30**, **32**, **33**, and **34**), and provides separate emission limits for startup, shutdown, and initial commissioning consistent with the emission levels shown in **AIR QUALITY Tables 13** and **16** (see Conditions of Certification **AQ-40** to **AQ-43**).

Emission Offsets

District Rules 20.1 and 20.3 require NOx and VOC offsets for a major modification to an existing major stationary source, defined as an emission increase of more than 25 tons per year for NOx or VOC. The net emissions increase from the new facility, the CECP permitted emissions minus the baseline emissions from the existing Encina boiler units 1, 2, and 3, would exceed the District's NOx offset threshold level but not the VOC offset threshold, as shown in **AIR QUALITY Table 19**. The applicant has proposed to offset NOx emission through NOx and VOC emission reduction credits, using the interpollutant ratio of 2:1 for VOC ERCs for NOx emissions and the District's Federal Offset Requirement ratio of 1.2 to 1 for both interpollutant traded VOC offsets and NOx offsets. The applicant has proposed four offset certificates that total, after application of the interpollutant offset ratio, 49.6 tons of NOx equivalent per year. This amount is more than sufficient, with the offset ratio of 1.2 to 1, to offset the proposed 39.9 ton/year NOx emission increase.

Air Quality Table 26
NOx Offsets Surrendered for Carlsbad

Pollutant	Location	Credit Number	ERC Amount (tpy)	NOx equivalent Amount (tpy)
NOx	Naval Air Station – North Island	978938-05	35.3	35.3
NOx	3200 Harbor Drive, San Diego	981518-01	2.3	2.3
VOC	850 Lagoon Drive, Chula Vista	070823-02	5.3	2.65
VOC	7757 Andrews Avenue, San Diego	080212-01	18.7	9.35
			Total ERC	49.6
			Total Required (at 1.2:1 ratio)	47.88
			Total Surplus	1.72

Source: FDOC (SCAQMD 2009)

Air Quality Table 26 shows that the total amount of NOx ERCs available (49.6 tpy) exceeds the District's offset requirements based on the revised potential to emit emission increase of 39.9 tpy. This offset proposal also meets staff's recommended minimum offset ratio of 1:1.

The applicant has proposed (SR 2009a) the use of 2.9 tons of PM10 ERCs that they currently own and fund the creation of emission reduction credits for the remainder of the PM10 and VOC credits to meet CEC recommended 1:1 emission mitigation for the other non-attainment pollutant and precursors that have permitted emission increases (PM10 and VOC). The maximum permitted emission increases are 7.6 tons PM, based on PM2.5, and 8.4 tons of VOC during initial commissioning.

CO is attainment for the region. No offsets are proposed or required.

Adequacy of Proposed Mitigation

Staff concurs with the District's determination that the project's proposed emission controls/emission levels for criteria pollutants and ammonia slip meets BACT requirements and that the proposed emission levels are reduced to the lowest technically feasible levels. Staff also concurs that the applicant's District offset proposal would fully mitigate the proposed project's net NOx emissions increase.

Staff accepts the Applicant's newly proposed offset strategy to meet staff recommended mitigation levels, and provides specifics on its recommended implementation below in the staff proposed mitigation section.

Staff Proposed Mitigation

Staff is proposing Condition of Certification **AQ-SC7** to ensure that onsite soil remediation activities, other than transportation of contaminated soils would not occur at the project site. On-site soil remediation activities, such as soil farming, have not been analyzed and would increase emissions and localized impacts during construction.

Staff is proposing Conditions of Certification (**AQ-SC6** and **AQ-SC8**) that would ensure that the license is amended as necessary to incorporate changes to the air quality permits and ensure ongoing compliance through the requirement of quarterly reports.

Staff is proposing Condition of Certification **AQ-SC9** to ensure that initial commissioning occurs sequentially with only one turbine undergoing initial commissioning at a time as proposed by the applicant and evaluated in the impact assessment.

Staff proposes Condition of Certification **AQ-SC10** to specify the following four methods that the applicant can use to offset its emission increases for PM and VOC:

1. ERCs from the SDAPCD bank that are currently owned by the applicant.
2. Create enforceable emission reductions from the site, such as by shutting down the existing peaking turbine.
3. Create enforceable emission reductions from third party sources, which could be accomplished by funding the Carl Moyer Program[5] or a similar emission reduction program specific to this project[6].

[5] The ARB Carl Moyer Web page has the following description of the program: "The Carl Moyer Memorial Air Quality Standards Attainment Program provides incentive grants for cleaner-than-required engines, equipment and other sources of pollution providing early or extra emission reductions. Eligible projects include cleaner on-road, off-road, marine, locomotive and stationary agricultural pump engines, as well as forklifts, airport ground support equipment, and auxiliary power units. The program achieves near-term reductions in emissions of oxides of nitrogen

4. ERCs from the SDAPCD bank to be obtained by the applicant only if local emission reduction projects are clearly demonstrated to be unavailable, using methods 2 or 3 above, to meet the total emission reduction liability.

Assuming that the applicant does use their currently owned PM10 credits to partially meet the staff recommended offset liability, the applicant's emission reduction fee for the remaining 13.1 tons of emissions would equal $251,520.

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

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

CUMULATIVE IMPACTS

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

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

Much of the preceding discussion is concerned with cumulative impacts. The "Existing Ambient Air Quality" subsection describes the air quality background in the San Diego Air Basin, including a discussion of historical ambient levels for each of the significant criteria pollutants. The "Construction Impacts and Mitigation" subsection discusses the project's contribution to the local existing background caused by project construction. The "Operation Impacts and Mitigation" subsection discusses the project's contribution

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(NOx), particulate matter (PM), and reactive organic gas (ROG) which are necessary for California to meet its clean air commitments under the State Implementation Plan Program funds" (ARB 2008e).

[6] An example of a power plant project that completed a project specific emission reduction program is the Otay Mesa Power Plant Project.

to the local existing background caused by project operation. The following subsection includes four additional analyses:

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

Summary of Projections

The SDAPCD has developed several elaborate plans to implement the federal Clean Air Act and state law as it addresses the cumulative air impacts of criteria pollutants in the San Diego air basin. These plans evaluate the regional context of air pollution in the air basin, and provide the air district strategies for addressing these cumulative impacts and eventually achieving "attainment" with various federal and state standards.

The SDAPCD is the lead agency for managing air quality and coordinating planning efforts for San Diego County and the San Diego Air Basin, so that the federal 8-hour ozone standard is attained in a timely fashion and attainment with CO standards are maintained. The District is responsible for developing those portions of the State Implementation Plan (SIP) and the Air Quality Management Plan (AQMP), that deal with certain stationary and area source controls and, in cooperation with the transportation planning agencies (TPAs), the development of transportation control measures (TCMs). Additionally, the SDAPCD is responsible for providing plans for attaining the California ozone standard and for reducing particulate (PM10 and PM2.5) emissions in compliance with Senate Bill 656 (Sher, Chapter 738, Statutes of 2003). In this role, the SDAPCD is the agency with principal responsibility for analyzing and addressing cumulative air quality impacts, including the impacts of ambient ozone, particulate matter, and CO. The District has summarized the cumulative impacts of ozone, particulate matter, and CO on the air basin from the broad variety of its sources. Analyses of these cumulative impacts, as well as the measures the District proposes to reduce impacts to air quality and public health, are summarized in six publicly available documents. These adopted air quality plans are summarized below.

- Eight-Hour Ozone Attainment Plan (federal 8-hour ozone attainment plan)
  Link: http://www.sdapcd.org/planning/8-Hour-Ozone-Attainment-Plan.pdf
- Air Resources Board's Proposed State Strategy for California's 2007 State Implementation Plan (federal 8-hour ozone attainment plan)
  Link: http://www.arb.ca.gov/planning/sip/2007sip/2007sip.htm
- Ozone Redesignation Request and Maintenance Plan (federal 1-hour ozone maintenance plan)
  Link: http://www.sdapcd.org/planning/RedesigPlan.pdf
- 2004 Revision to the California State Implementation Plan for Carbon Monoxide (federal CO maintenance plan)
  Link: http://www.arb.ca.gov/planning/sip/co/final_2004_co_plan_update.pdf

- 2004 Triennial Revision of the Regional Air Quality Strategy for San Diego County (state ozone attainment plan)
  Link: http://www.sdapcd.org/planning/RAQS-04.pdf
- Measures to Reduce Particulate Matter in San Diego County (Health and Safety Code 39614)
  Link: http://www.sdapcd.org/planning/SB656StaffRpt.pdf

The final 8-hour ozone attainment plan for San Diego County was submitted by the state in the ARB *Proposed State Strategy for California's 2007 State Implementation Plan* document in late 2007. This plan has not been approved by U.S. EPA, so the approved 1-hour plan is the currently approved ozone attainment plan for San Diego County. The 2007 State Implementation Plan, when approved by U.S. EPA, will become the ozone attainment plan for the District.

Eight-Hour Ozone Attainment Plan and Air Resources Board's Proposed State Strategy for California's 2007 State Implementation Plan

The District's Eight-Hour Ozone Attainment plan relies strongly on existing control measures included in District rules and regulations. The ARB's state proposed strategy for the State Implementation Plan relies primary on existing control measures, as well as tightening vehicle emissions (both on- and off-road vehicles) and emissions from other transportation sources, pesticides, and consumer products. No new control strategies that are directly applicable to the project are noted in either of these two ozone planning documents. Indirectly, the on-road and off-road control measures would regulate some of the delivery vehicles and construction equipment used during the projects construction and operation. U.S. EPA has not yet approved the 8-hour ozone attainment plan for California.

Ozone Redesignation Request and Maintenance Plan

This plan was prepared after the SDAB came into compliance with the federal 1-hour ozone standard in December 2002. U.S. EPA approved this plan and redesignated the San Diego Air Basin as attainment with the 1-hour standard effective July 28, 2003. The specific control measures included in the approved 1-hour ozone maintenance plan are those that were approved for the nonattainment State Implementation Plan (SIP), and no new measures were proposed. The existing measures from the previously approved SIP are included in the District's rule and regulations and ARB vehicle emission regulations. Therefore, compliance with these rules and regulations would ensure that the project conforms to the 1-hour ozone maintenance plan.

While the San Diego area is no longer subject to the revoked federal 1-hour ozone standard, the 8-hour ozone plan has not yet been approved by U.S. EPA, so this plan is the currently approved ozone plan for San Diego County.

2004 Revision to the California State Implementation Plan for Carbon Monoxide

The Carbon Monoxide Maintenance Plan applies to 10 separate areas in California that attained the federal CO standards in the 1990s, including the San Diego area. This plan does not include any further measures or requirements that would specifically relate to the project's direct and indirect emission sources. This plan relies on current motor

vehicle programs to ensure that attainment with the federal CO standards are maintained.

The project's construction and operation were not found to cause any new exceedances of the carbon monoxide ambient air quality standards (CO AAQS). The project's generated traffic would be insignificant in comparison with the existing San Diego County traffic, and the project's primary emission sources normally emit CO concentrations out of the stack that are below the federal ambient air quality standards. Therefore, the project would not impact the Carbon Monoxide Maintenance Plan.

2004 Triennial Revision of the Regional Air Quality Strategy for San Diego County

This plan is prepared to determine progress and measures needed to attain California Ambient Air Quality Standards (CAAQS) for ozone, carbon monoxide, nitrogen dioxide, and sulfur dioxide. San Diego County is in attainment with all of these state standards except ozone. This plan describes the extent of ozone air quality improvement during the previous three years, provides a discussion of actual versus forecasted ozone precursor emission rates, and evaluates the need for further control measures in order to achieve attainment with the state ozone ambient air quality standards. None of the measures determined for further study in this document would apply to the proposed project.

The draft triennial plan was completed in August 2008, but is has not yet been officially approved (SDAPCD 2008c). None of the emission reduction measures proposed in the draft document, which includes a Best Available Retrofit Control Technology (BARCT) measure for existing older peaker turbines and a control measure for small boilers (less than 5 million Btu/hr heat input), would impact the new gas turbines and internal combustion engines that would be installed as part of this project.

Measures to Reduce Particulate Matter in San Diego County

This plan, completed in December 2005, analyzed potential particulate control measures, listed by ARB, as required by Health and Safety Code 39614. The SDAPCD's review indicated that 59 of these ARB measures were already included in existing District rules and regulations, that 25 of these control measures would not significantly reduce particulate emissions in San Diego County, and that 19 of these control measures could have cost effective particulate reductions. The District will evaluate these 19 control measures further and will propose new regulations, or non regulatory programs, for consideration of the District Board, if appropriate. Of these 19 control measures, there are eight fugitive dust control measures that could be applicable to the project's construction activities, including earthmoving, demolition, grading, carryout and trackout, unpaved staging areas, and windblown dust controls. The District has not yet promulgated any regulations for fugitive dust control; however, a fugitive dust rule is planned to be promulgated prior to the end of the project's construction. Staff's proposed fugitive dust control measures (Condition of Certification **AQ-SC3** and **AQ-SC4**) require stringent emission control measures for all of the applicable fugitive dust sources that are identified for further study in this planning document and that are likely to be included in the District's future fugitive dust control rule.

Summary of Conformance with Applicable Air Quality Plans

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

SDAPCD recently evaluated additional fugitive dust control measures and recently adopted a fugitive dust control rule (Rule 55, effective December 24, 2009). Staff's recommended Conditions or Certification **AQ-SC3** and **AQ-SC4** include fugitive dust control measures that should meet or exceed the fugitive dust control requirements of new SDAPCD Rule 55. However, **AQ-SC3** has been revised to include the potential that specific fugitive dust control measures that are required by SDAPCD Rule 55 could be more stringent than those currently required in staff's proposed conditions.

Localized Cumulative Impacts

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

- First, the Energy Commission staff (or the applicant) works with the air district to identify all projects that have submitted, within the last year of monitoring data, new applications for an authority to construct (ATC) or permit to operate (PTO) and applications to modify an existing PTO within six miles of the project site. Based on staff's modeling experience, beyond six miles there is no statistically significant concentration overlap for non-reactive pollutant concentrations between two stationary emission sources.
- Second, the Energy Commission staff (or the applicant) works with the air district and local counties to identify any new area sources within six miles of the project site. As opposed to point sources, area sources include sources like agricultural fields, residential developments or other such sources that do not have a distinct point of emission. New area sources are typically identified through draft or final Environmental Impact Reports (EIRs) that are prepared for those sources. The initiation of the EIR process is a reasonable basis on which to determine what is "reasonably foreseeable" for new area sources.
- The data submitted, or generated from the applications with the air district for point sources or initiating the EIR process for area sources, provides enough information to include these new emission sources in air dispersion modeling. Thus, the next step is to review the available EIR(s) and permit application(s), determine what sources must be modeled and how they must be modeled.
- Sources that are not new, but may not be represented in ambient air quality monitoring are also identified and included in the analysis. These sources include existing sources that are co-located with or adjacent to the proposed source (such

as the existing Encina Power Plant). In most cases, the ambient air quality measurements are not recorded close to the proposed project, thus a local major source might not be well represented by the background air monitoring. When these sources are included, it is typically a result of there being an existing source on the project site and the ambient air quality monitoring station being more than two miles away.

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

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

The original list of possible new sources from the SDAPCD included 5 sources (CECP 2007a, Appendix 5.1F. Of the 5 stationary sources identified by SDAPCD:

- One was identified to be outside of the six mile radius.
- Four were identified to have emissions less than 5 tons/year of any criteria pollutant, and so would not have a significant potential to create significant cumulative impacts

Therefore, the local cumulative assessment for CECP, which is comprised of a short-term modeling analysis for worst-case NO_2 and CO impacts, only includes the existing Encina Power Plant facilities that would remain in operation after the construction of the project.

There are proposed construction projects near the proposed project site such as the I-5 widening project[7]; however, the timeframe and emissions from these projects is unknown and these construction projects would be limited in duration. Meanwhile emissions from existing mobile emission sources, such as the I-5 freeway, and temporary construction emission sources are forecast to have long-term emission reductions or significantly reduced emission potentials for most pollutants through improvements in on-road and off-road vehicle engine technology and vehicle turnover, respectively.

The applicant used stack and building parameters and emission data for the existing Encina Power Plant, specifically boiler units 4 and 5 that would remain after construction of the project, and generally followed the same modeling procedures used for the CECP operating emissions modeling analysis, using the most recent version of AERMOD (Version 07026). The optional PVMRM method available with AERMOD, discussed under the operating impacts section, was used to model the short-term NOx impacts. The modeling assumed worst-case short-term emissions for the CECP (cold startup) and assumed full load emissions for the existing Encina Power Station boiler units 4 and 5 and peaking turbine. The results of the applicant's cumulative modeling analysis are provided in **AIR QUALITY Table 27**.

AIR QUALITY Table 27
Cumulative Impacts Modeling Results (µg/m^3)

Pollutant	Averaging Period	Project Impact (µg/m^3)	Background (µg/m^3) [a]	Total Impact (µg/m^3)	Limiting Standard (µg/m^3)	Type of Standard	Percent of Standard
NO_2	1 hour	133.5	152.6	286.1	339	CAAQS	84%
	annual [b]	0.3	22.8	23.1	57	CAAQS	41%
PM10	24 hour [c]	7.1	57	64.1	50	CAAQS	128%
	annual	0.1	24.2	24.3	20	CAAQS	122%
PM2.5	24 hour [c]	7.1	37.7	44.8	35	NAAQS	128%
	annual	0.1	12	12.1	12	CAAQS	101%
CO	1 hour	3,228	6,785	10,013	23,000	CAAQS	44%
	8 hour	676	4,011	4,687	10,000	CAAQS	47%
SO_2	24 hour [c]	10.5	23.6	34.1	105	CAAQS	32%
	annual	0.1	10.7	10.8	80	NAAQS	14%

Source: CECP Cumulative Assessment (SR 2008f).
[a] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 10**.
[b] Annual NO2 impact has been multiplied by the U.S.EPA Ambient Ratio Method value of 0.75.
[c] These 24-hour values are all based on worst-case existing Encina Boilers firing oil, when firing natural gas the worst-case cumulative PM10/PM2.5 and SO2 impacts are 1.4 and 0.4 µg/m^3, respectively.

[7] A draft environmental document has not yet been prepared for the I-5 widening project, and due to the delay in the environmental documentation it is likely that the project will not begin construction near the CECP project site until sometime between 2015 and 2020, so the CECP construction and I-5 widening project construction will not occur at the same time in the same general area (i.e. no cumulative air quality impacts). The CECP operation and the I-5 widening construction are expected to have maximum air quality impacts in different locations due to the differences in the types emission sources and their relative buoyancy and downwind dispersion. Therefore, significant cumulative impacts from the CECP operation and I-5 widening construction are not expected.

The results of this modeling effort, **AIR QUALITY Table 27**, show that CECP, along with the existing Encina Power Station, would not contribute to new short-term AAQS violations for NO_2 or CO.

The CECP would mitigate emissions through the use of BACT and District required and staff recommended banked or new, owner-funded, emission reductions. Therefore, the cumulative operating impacts after mitigation are considered to be less than significant.

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

Localized Heat Impacts

The Carlsbad community has expressed concerns regarding the potential for direct impacts to local air temperatures from the new gas turbine/HRSG stacks and two air-cooled fin-fan cooler units, both of which emit their heat at much lower heights than the existing combined boiler stack. Additionally, while the maximum heat rejection from the existing Encina facility boilers 1-3 is much higher than the CECP, the heat is rejected using a once-through ocean water cooling system which would not be expected to impact local air temperatures significantly. Staff conducted a modeling analysis to determine the potential localized heat impacts[8]. The AERMOD dispersion model was used and proxy emission rates were substituted for heat flux values. Both short-term and long-term incremental heat impacts were determined. **AIR QUALITY Table 28** provides the results from the modeling analysis.

AIR QUALITY Table 28
Localized Heat Impact Modeling Results

Equipment Type	Temperature Increase
1-Hour Peak Impacts	
HRSGs (both)	1.92°F
Fin Fan Coolers (both)	1.65°F
Entire Facility	1.35°F
Annual Average Impacts	
HRSGs (both)	0.012°F
Fin Fan Coolers (both)	0.0084°F
Entire Facility	0.0055°F

Source: Staff Modeling Analysis

Note: the HRSG and Fin Fan Cooler worst case impacts cannot be added for the determination of the entire facility impacts as the peak impacts from each occur at different locations.

The worst-case annual average heat impacts are very minor at only 0.012 degrees Fahrenheit at any specific location. The maximum 1-hour heat impacts were determined to occur in locations that were on hilltops or ridges to the west southwest of the project site that are not populated; however, the maximum heat impacts found in the nearby adjacent populated areas were determined to be nearly as high as these maximums. While the highest hourly impact is over 1.5 degrees Fahrenheit the frequency of impacts

[8] This analysis modeled the heat from the fin-fan coolers using an equivalent stack approach.

above 1 degree Fahrenheit in populated areas was determined to be less than ten hours per year. Additionally, the heat impacts to the populated areas occur during onshore wind conditions that are generally consistent with cooler conditions, for example the peak one-hour impact was determined during an ambient temperature of under 70 degrees Fahrenheit. Thus, any increases in temperature would be relatively small even when calculated with conservative modeling assumptions, would be transient in nature.

The model used has inherent conservatism for heat modeling due to several factors including: 1) the additive effect of adjacent heat plumes on total plume rise is not considered by the model; 2) the model in general is fairly conservative (under predictive) regarding plume rise in order to be conservative regarding the assessment of ground level impacts; 3) while the AERMOD model attempts to adjust for terrain it is still somewhat conservative when providing impacts at locations well above stack height; and 4) most importantly the heat input emissions proxy value was kept at maximum full load value while the exhaust temperature was held a conservatively low value of 100F which would reduce the heat induced plume rise. Additionally, the small reduction in direct heat impacts from the operation of boilers 1-3 has not been considered. For these reasons it is felt that these modeling results are conservative and likely over predict the direct ground level heat impacts from the CECP.

COMPLIANCE WITH LORS

The San Diego Air Pollution Control District issued a Preliminary Determination of Compliance (PDOC) for the CECP on November 21, 2008, with public notice occurring on November 25, 2008 (SDAPCD 2008b). The District issued a Final Determination of Compliance (FDOC) on August 4, 2009 (SDAPCD 2009) that included consideration of comments received from responsible agencies and the public. Compliance with all District Rules and Regulations was demonstrated to the District's satisfaction in the FDOC. The District's FDOC conditions are presented in the Conditions of Certification. Staff submitted comments on the PDOC, and is satisfied with the District's responses and the FDOC.

FEDERAL

The District is responsible for issuing the Federal New Source Review (NSR) permit but is not currently delegated enforcement for the Prevention of Significant Deterioration (PSD) permitting process. The applicant has stipulated to emission levels that ensure that the project's net emission increase of pollutants would be below PSD permit trigger levels. The District's FDOC permit conditions have been designed to ensure that the project will comply with the applicable NSPS Subparts KKKK and IIIII that are delegated to the District for enforcement as part of its Title V permit responsibility.

STATE

The applicant would demonstrate that the project would comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury, with the issuance of the District's Final Determination of Compliance and the Energy Commission's affirmative finding for the project.

The District has evaluated compliance of the emergency diesel fire pump engine with Air Toxic Control Measure (ATCM) requirements under Title 17 of the California Code of Regulations. The District has determined, with their FDOC permit conditions, that the engine will comply with the ATCM requirements

LOCAL

The applicant provided an air quality permit application to the SDAPCD in 2007 and the District has issued a FDOC (SDAPCD 2009), which states that the proposed project is expected to comply with all applicable District rules and regulations.

The District rules and regulations specify the emissions control and offset requirements for new sources such as the CECP. Best Available Control Technology would be implemented, and emission reduction credits (ERCs) for NOx emissions are required by District rules and regulations based on the permitted emission levels for this project. Compliance with the Districts new source requirements would ensure that the project would be consistent with the strategies and future emissions anticipated under the Districts air quality attainment and maintenance plans.

As part of the Energy Commission's licensing process, in lieu of issuing a construction permit to the applicant for the CECP, the District will prepare and present to the Commission a DOC, both a PDOC, and after a public comment period, an FDOC. The PDOC was published on November 21, 2008 with public notice occurring on November 25, 2008. The FDOC was issued on August 4, 2009. The FDOC evaluates whether and under what conditions the proposed project would comply with the District's applicable rules and regulations, as described below.

Regulation II – Permits

Rule 20.1 and 20.3 – New Source Review

Rules 20.1 and 20.3 generically apply to all sources subject to permitting under the nonattainment NSR and PSD programs. All portions of Rule 20.1 apply. This includes definitions and instructions for calculating emissions. Applicable components of Rule 20.3 are described below.

Rule 20.3(d)(1) – Best Available Control Technology/Lowest Achievable Emission Rate

This subsection of the rule requires that BACT be installed on a pollutant specific basis if emissions exceed 10 lbs/day for each criteria pollutant (except for CO, for which the PSD BACT threshold is 100 tons per year). This subsection also requires that Lowest Achievable Emission Rate (LAER) be installed on a pollutant specific basis, for federal nonattainment pollutants and precursors, if the project is a new major source or a major modification to an existing major source. Because the District attains the national ambient air quality standards for CO, SO2, and PM10, LAER does not apply to these particular pollutants (District Rule 20.3(d)(1)(v)). The project is defined as a major modification to an existing major source based on the net emissions increase of NOx being greater than 25 tons per year, but the net emissions increase of VOC is below the 25 ton per year threshold. Therefore, LAER is required for the gas turbines NOx

emissions. The emergency fire pump engine is exempt from LAER requirements. BACT is required for VOC, PM10, and SOx.

The District has determined, with some revisions to the pollutant averaging periods, and a reduction of the VOC emission limit from 2.0 ppm to 1.5 ppm (@15% O_2) that the project meets LAER and BACT requirements.

Rule 20.3(d)(2) – Air Quality Impact Analysis

This portion of the rule requires that an Air Quality Impact Analysis (AQIA) be performed for air contaminants that exceed the trigger levels published in Table 20.3-1 of the District's Rules and Regulations. For an AQIA of PM10, the rules require that direct emissions and emissions of PM10 precursors be included in the analysis.

The CECP has prepared an AQIA for NOx, CO, and PM10 that was evaluated by District Staff as part of the FDOC analysis.

Rule 20.3(d)(4) – Public Notice And Comment

This portion of the rule requires the District to publish a notice of the proposed action in at least one newspaper of general circulation in San Diego County and requires sending notices to the U.S. EPA and the ARB. The District must allow at least 30 days for public comment and consider all comments submitted. The District must also make all information regarding the evaluation available for public inspection.

The official public notice and comment period for the CECP started after newspaper notice publication on November 25, 2008 and ended on December 24, 2008. Rule 20.3(d)(4)(i) requires that the District consider all comments received. The District considered all comments received before taking final action in the FDOC.

Rule 20.3(d)(5) – Emission Offsets

This portion of the rule requires that emissions of any federal nonattainment criteria pollutant or its precursors, which exceed major source thresholds, be offset with actual emission reductions. The District is a federal nonattainment area only for ozone. Therefore, this rule requires offsets only for NOx and VOC emissions, as ozone precursors, if the project's net emissions increase greater than 25 tons per year for these two pollutants. The CECP permitted emission increase of NOx is greater than the offset threshold but the permitted emission increase of VOC is below the offset threshold. Therefore, offsets are only required by the District for NOx emissions. Based on the permitted emission limits the net emission increase is 39.9 tons per year of NOx, and the District required offset ratio of 1.2 to 1, the total NOx Emission Reduction Credit (ERC) requirement for the project is 47.88 tons. The FDOC conditions (incorporated into this FSA) would require that all required NOx ERCs are provided prior to gas turbine start-up.

The applicant has obtained NOx and VOC ERCs (used as ozone precursor interpollutant offsets - VOC for NOx) in quantities necessary to meet the Districts offset requirements (see Air Quality Table 26**). Compliance with this rule is expected. Rule 20.3(e)(1) – Compliance Certification**

This rule requires that the applicant certify that all major stationary sources owned or operated by the applicant in California are in compliance, or on an approved schedule for compliance, with all applicable emission limitations and standards under the federal Clean Air Act. This applicant owns Encina and other major stationary sources within California. The District's FDOC notes that the applicant has provided the required compliance certification.

Rule 20.5 – Power Plants

This rule requires that the District prepare a decision of Preliminary and Final Determinations of Compliance (PDOC and FDOC), which shall confer the same rights and privileges as an Authority to Construct only after successful completion of the Energy Commission's licensing process. The District has prepared the PDOC and FDOC.

Regulation IV – Prohibitions

Rule 50 – Visible Emissions

This rule prohibits air contaminant emissions into the atmosphere darker than Ringelmann Number 1 (20 percent opacity) for more than an aggregate of three minutes in any consecutive 60 minute time period. Compliance with this requirement is expected for the gas turbines and emergency fire pump engine.

Rule 51 – Nuisance

This rule prohibits the discharge of air contaminants that cause or have a tendency to cause injury, detriment, and nuisance or annoyance to people and/or the public or damage to any business or property. Compliance with this requirement is expected for the gas turbines and emergency fire pump engine.

Rule 52 – Particulate Matter

This rule is a general limitation for all sources of particulate matter to not exceed 0.10 grain per dry standard cubic foot (0.23 grams per dry standard cubic meter) of exhaust gas. The district calculated the maximum grain loading to be 0.004 grains per dry standard cubic foot, in compliance with the requirements of this rule.

Rule 53 – Specific Air Contaminants

This rule limits emissions of sulfur compounds (calculated as SO2) to less than or equal to 0.05 percent, by volume, on a dry basis. This rule also contains a limitation restricting particulate matter emissions from gaseous fuel combustion to less than or equal to 0.10 grains per dry standard cubic foot of exhaust calculated at 12 percent CO2. As shown above the project's particulate concentration is well below 0.1 grains per dry standard cubic foot, and the use of pipeline quality natural gas fuel would ensure compliance with the sulfur compound emission limitation of this rule.

Rule 55 – Specific Air Contaminants

This rule restricts visible dust from construction activities to reach beyond the property line for more than 3 minutes in any hour, and requires control of visible roadway dust from track-out/carry-out from truck wheels and truck spillage. This rule, which was adopted after publication of the PSA (June, 24, 2009), becomes effective on December 24, 2009. Staff recommended fugitive dust conditions (AQ-SC1 through AQ-SC4) are as stringent as or more stringent than the requirements of this rule.

Rule 62 – Sulfur Content of Fuels

This rule requires the sulfur content of gaseous fuels to contain no more than 10 grains of sulfur compounds, calculated as hydrogen sulfide, per 100 cubic feet of dry gaseous fuel (0.23 grams of sulfur compounds, calculated as hydrogen sulfide, per cubic meter of dry gaseous fuel), at standard conditions.

The use of pipeline quality natural gas would ensure compliance with this rule.

Rule 69.3 – Stationary Gas Turbines - Reasonably Available Control Technology

This rule limits NOx emissions from gas turbines greater than 0.3 MW to 42 ppm at 15 percent oxygen when fired on natural gas. The rule also specifies monitoring and record keeping requirements. Startups and shutdowns are excluded from compliance with these limits.

This rule's emission limits are less stringent than the BACT/LAER requirement of Rule 20.3(d)(1) for normal operation. The District has included conditions for the project to meet this emission limit during initial commissioning, low-load operation, tuning, and transient operation periods, such as during periods of major turbine load shifts.

Rule 69.3.1 – Stationary Gas Turbines - Best Available Retrofit Control Technology

This rule limits NOx emissions from existing and new gas turbines greater than 10 MW to 15 x (E/25) ppm when operating uncontrolled and 9 x (E/25) ppm at 15 percent oxygen when operating with controls and averaged over a one-hour period (where E is the percent thermal efficiency of the unit, typically between 30 to 40 percent for gas turbines). The District calculated this NOx standard to be equivalent to 21.9 ppm when uncontrolled and 12.6 ppm when controlled, based on a thermal efficiency for the turbines of 36.5 percent[9]. The rule also specifies monitoring and record keeping requirements. Startups and shutdowns are excluded from compliance with these limits.

This rule's emission limits are less stringent than the BACT/LAER requirement of Rule 20.3(d)(1) for normal operation. The District has included conditions for the project to meet this emission limit during initial commissioning, low-load operation, tuning, and transient operation periods, such as during periods of major turbine load shifts.

[9] This rule only considers the thermal efficiency of the turbine and does not include the additional efficiency of the heat recovery steam generator.

Rule 69.4.1 – Stationary Reciprocating Internal Combustion Engines – Best Available Retrofit Control Technology

This rule limits emissions of NOx and CO for diesel engines, has maintenance and recordkeeping requirements, and requires the use of California diesel fuel. NOx emissions are limited to 6.9 grams/bhp-hr, where the proposed emergency fire pump engine has an emission guarantee of 3.92 grams/bhp-hr. CO emissions are limited to 4500 ppmv at 15% oxygen, where the engine emissions are calculated to be 61.2 ppmv. This rule also exempts emergency engines from periodic source testing. The proposed engine meets the emission limits of this regulation and the District has included conditions to ensure compliance with the other applicable provisions of this regulation.

Regulation X – Standards of Performance for New Stationary Sources

Adopts federal New Source Performance Standards (NSPS, 40 CFR, Part 60) by reference. The relevant NSPS subparts for the CECP, Subpart KKKK (Stationary Combustion Turbines) and Subpart IIII (Stationary Compression Ignition Internal Combustion Engines) This rule's emission limits are less stringent than the BACT/LAER requirement of Rule 20.3(d)(1) for normal operation. The District's conditions would ensure compliance with the monitoring and recordkeeping requirements of this regulation.

Regulation XI – National Emission Standards for Hazardous Air Pollutants

Adopts federal standards for hazardous air pollutants (HAPs) by reference. The project, as being part of a major source of HAPs emissions, is subject to Subpart YYYY (Stationary Combustion Turbines) and Subpart ZZZZ (Compression Ignition Internal Combustion Engines). The District has incorporated conditions to ensure compliance with the emissions and operating limitations and monitoring requirements of these two regulations.

Regulation XII – Toxic Air Contaminants

Rule 1200 – Toxic Air Contaminants, New Source Review

This rule requires a health risk estimate for sources of toxic air contaminants. Toxics Best Available Control Technology (TBACT) must be installed if a Health Risk Assessment shows an incremental cancer risk greater than one in a million, and no source would be allowed to cause an incremental cancer risk exceeding ten in a million. The District found that the project, which was found to have an incremental cancer risk of less than one in a million, complied with the requirements of this rule. The Public Health Section of this Final Staff Assessment provides additional information on toxic air contaminants.

Regulation XIV – Title V Operating Permits

Rule 1401 – General Provisions

This regulation contains the requirements for federal Title V Operating Permits. The applicant is required to submit a revised Title V Operating Permit application no later

than 18 months after initial operation of the gas turbines. The Encina Power Station currently has a Title V Operating Permit and the applicant has submitted an application to the District to modify its Title V Operating permit to include the CECP.

Rule 1412 – Federal Acid Rain Program Requirements

This regulation contains the requirements for participation in the federal Acid Rain Program. The applicant is required to submit an Acid Rain Program application to the District 24 months prior to initial startup of the gas turbines. The applicant submitted the Acid Rain permit application to the District on September 4, 2008.

NOTEWORTHY PUBLIC BENEFITS

Three existing power boilers (Units 1 through 3) that total 314 MW of generation capacity would be shut down following the commissioning of the new units. The three existing boiler units would need to be shut down once the new gas turbines are in commercial operational in order for the new emissions of CECP to be allowed by the SDAPCD.

The proposed project would improve the overall thermal efficiency of the power plant due to the higher efficiency of the two new Siemens SGT6-PAC5000F gas turbines compared to the three existing power boilers. This along with an improved emission control system for the new Siemens SGT6-PAC5000F gas turbines leads to a reduction in emissions of most pollutants emitted per unit of electricity produced. It also leads to a reduction in amount of natural gas fuel consumed to generate the same amount of power. Additionally, facilities of this nature, with quick-start capabilities, are needed to support California's efforts to increase use of renewable resources that will reduce system wide criteria pollutant emissions from power generation.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

The response to agency and public comments on the PSA Air Quality Section are summarized in **Appendix AIR-2 Response to PSA Comments**. As indicated in **Appendix AIR-2**, a number of revisions were made to this staff assessment as part of the response to the agency and public comments.

CONCLUSIONS

Staff concludes that:

- The project would comply with applicable District Rules and Regulations, including New Source Review Best Available Control Technology (BACT) and offset requirements, and staff recommends the inclusion of the Districts FDOC conditions as Conditions of Certification **AQ-1** through **AQ-100**.
- The project's construction activities, if unmitigated, would likely contribute to significant adverse PM10 and ozone impacts. Staff recommends **AQ-SC1** to **AQ-SC5** to mitigate the potential impacts.

- The project's operation would not cause new violations of any NO_2, SO_2, PM2.5 or CO ambient air quality standards, and therefore, the project's direct operational NOx, SOx, PM2.5 and CO emission impacts are not significant.
- The project's direct, or secondary, emissions contribution to existing violations of the ozone and PM10 ambient air quality standards are potentially significant if unmitigated. The District will require offsets to mitigate the NOx emission increase (**AQ-5**) but does not require offsets for the other potential pollutant increases. Therefore, staff recommends **AQ-SC10** to mitigate the potential emission increases that do not require District offsets, so that all nonattainment pollutant and precursor emissions be offset at least one-to-one.
- The project would be consistent with the requirements of SB 1368 and the Emission Performance Standard for greenhouse gases (see **Appendix Air-1**).

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

Staff has proposed a number of additional conditions that are in addition to the permit conditions that the SDAPCD has proposed, or the other staff recommended conditions noted above. Condition **AQ-SC6** provides the administrative procedure requirements for project modifications. Condition **AQ-SC7** forbids onsite contaminated soil remediation activities, other than transport, as onsite soil remediation was not proposed or analyzed as part of the project. Condition **AQ-SC8** is a quarterly compliance reporting requirement. Condition **AQ-SC9** allows only one gas turbine at a time to undergo initial commissioning as proposed by the applicant and evaluated in the impact assessment.

Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in **Appendix Air-1**. The Carlsbad Energy Center, as a peaking or mid-merit project with an enforceable operating capacity factor of less than 60 percent is not subject to the requirements of SB1368 and the Emission Performance Standard, although this highly efficient project would meet the CO_2 emission requirements of this standard. The project will emit over 0.8 million metric tonnes of carbon dioxide equivalent emissions and therefore will be subject to mandatory GHG reporting requirements. It may also be subject to GHG reductions or trading requirements as these regulations are implemented

PROPOSED CONDITIONS OF CERTIFICATION

Staff recommends the following conditions of certification to address the impacts associated with the construction and operation of the CECP project. These Conditions include the SDAPCD proposed conditions from the FDOC, with appropriate staff proposed verification language for each condition, as well as Energy Commission staff proposed conditions.

STAFF CONDITIONS

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

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the 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 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with conditions AQ-SC3, AQ-SC4, and AQ-SC5.

Verification: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the 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 the 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 laydown 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 reduced or eliminated during periods of precipitation.

B. No vehicle shall exceed 10 miles per hour on unpaved areas within the project and laydown construction sites.

C. The construction site entrances shall be posted with visible speed limit signs.

D. All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned and 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 measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent runoff 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 the construction site shall be swept visually clean, using wet sweepers or air filtered dry vacuum sweepers, at least twice daily (or less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff 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 shall be 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 in a manner 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.

N. Disturbed areas will be re-vegetated as soon as practical.

The fugitive dust requirements listed in this condition may be replaced with as stringent or more stringent methods as required by SDAPCD Rule 55.

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 Delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported (1) off the project site or (2) 200 feet beyond the centerline of the construction of linear facilities, (3) within 100 feet upwind of any regularly occupied structures not owned by the project owner, or (4) within 50 feet upwind of the I-5 freeway indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes, other than those occurring upwind of the I-5 Freeway, 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 shut-down 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.

The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes occurring upwind of the I-5 Freeway are observed:

Step 1: The AQCMM or Delegate shall immediately cease the activities causing the visible dust plumes if any obscuration of visibility is occurring to drivers on the I-5 freeway. The AQCMM or Delegate shall direct more intensive application of the existing mitigation methods immediately if the visible plumes are seen within 50 feet of the I-5 freeway but are not causing obscuration of visibility to drivers.

Step 2: The AQCMM or Delegate shall direct implementation of additional methods of dust suppression and monitor the start-up and/or continuation of the dust causing activities to ensure that the additional mitigation is effective.

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. 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 that could impact visibility on the I-5 Freeway will not occur upon restarting the shut-down source.

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

AQ-SC5 Diesel-Fueled Engines Control: The AQCMM shall submit to the CPM, in the MCR, a construction mitigation report that demonstrates compliance with the following mitigation measures for the 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 be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur.

B. 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.

C. A good faith effort shall be made to find and use off-road construction diesel equipment that has a rating of 100 hp to 750 hp and that meets the Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines as specified in Title 13, California Code of Regulations section 2423(b)(1). 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.

D. All construction diesel engines, which have a rating of 50 hp or more, shall meet, at a minimum, the Tier 2 California Emission Standards for Off-Road Compression-Ignition Engines as specified in Title 13, California Code of Regulations section 2423(b)(1). The following exceptions for specific construction equipment items may be made on a case-by-case basis.

(1) Tier 1 equipment will be allowed on a case-by-case basis only when the project owner has documented that no Tier 2 equipment is available for a particular equipment type that must be used to complete the project's construction. This shall be documented with

signed written correspondence by the appropriate construction contractors along with documented correspondence with at least two construction equipment rental firms.

(2) The construction equipment item is intended to be on site for five days or less.

(3) 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.

A. All heavy earthmoving equipment and heavy duty construction-related trucks with engines meeting the requirements of (c) above shall be properly maintained and the engines tuned to the engine manufacturer's specifications.

B. All diesel heavy construction equipment shall not remain running at idle for more than five minutes, to the extent practical.

C. 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) copies of all diesel fuel purchase records, (3) a list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that equipment has been properly maintained, and (4) 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 not conduct any on-site remediation of contaminated soils at the project site, other than removal and transport.

Verification: The project owner shall provide transportation and disposition records of the contaminated soil removal and offsite remediation completion demonstrating compliance with this condition as part of the MCR until the contaminated soil removal is complete.

AQ-SC8 The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter that include operational and emissions information as necessary to demonstrate compliance with the Conditions of Certification herein. The Quarterly Operation Report will specifically note or highlight incidences of noncompliance.

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

AQ-SC9 Only one combustion turbine shall undergo commissioning at a time.

Verification: The project owner shall provide the CPM CEMS data demonstrating compliance with this condition as part of the monthly commissioning status report (**AQ-80**).

AQ-SC10 The project owner shall provide emission reduction mitigation to offset the project's PM (based on PM2.5) and VOC emission increases at a ratio of 1:1. These emission reductions are based on the following maximum annual emissions for the facility (tons/yr).

Emission Reduction Credits/Pollutant	**Tons/yr**
PM10	7.6
VOC	8.4
Total Tons	16.0

Emission reductions can be provided using any one of the following methods in the following order of preference of their use:

1. Additional enforceable emission reductions created at the Encina Power Station site, such as the permanent shutdown of the Encina gas turbine peaker.

2. The project owner can fund enforceable emission reductions through the Carl Moyer Fund in the amount of $16,000/ton, or the applicable ARB Carl Moyer Program Guideline cost effectiveness cap value at the time of funding the emission reductions, for the total ton quantity listed in the above table, minus any tons offset using the other two listed methods, with an additional 20% administration fee to fund the SDAPCD and/or other responsible local agencies with jurisdiction within 25 miles of the project site to be used to find and fund local emission reduction projects to the extent feasible. Emission reduction projects funded by this method will be weighted for evaluation and selection, within the funding guideline value of $16,000/ton of reduction, or revised current funding guideline limit value, based on the proximity of the emission reduction project and the relative health benefit to the local community surrounding the project site. Emission reduction project cost will not be a consideration for selection as long as the emission reduction project is within the approved 2008, or later year as applicable, Carl Moyer funding guideline value,

3. The project owner can fund other existing public agency regulated stationary or mobile source emission reduction programs or create a project specific fund to be administered through the SDAPCD or other local agency, which would provide enforceable surplus emission reductions. This funding shall include appropriate administrative fees as determined by the administering agency to obtain local emission reductions to the extent feasible. The project owner shall be responsible for demonstrating that the amount of such funding meets the emission reduction requirements of this condition. Emission reduction projects funding by this method will be weighted for evaluation and selection based on the proximity of the emission reduction project and the relative health benefit to the local community surrounding the project site.

4. 2.9 tons of PM10 ERCs currently owned by the applicant can be used to partially offset the PM emissions increase.

5. ERC certificates from other emission reductions occurring in the San Diego Air Basin can be purchased and used to offset each pollutant on a 1:1 offset ratio basis only if local emission reduction projects are clearly demonstrated to be unavailable using methods 1 to 3 to meet the total emission reduction burden required by this condition. ERCs can be used on an interpollutant basis for SOx for PM10 and NOx for VOC, where the project owner will provide a letter from the SDAPCD that indicates the District's allowed interpollutant offset ratio, or PM10 for SOx ERCs can be used on a 1:1 basis.

Carl Moyer or other emission reduction funding shall be provided to the responsible agencies prior to the initiation of on-site construction activities. The project owner shall work with the appropriate agencies to target emission reduction projects in the project area to the extent feasible. Emission reduction project selection information will be provided to the CPM for review and comment. Unused administrative fees shall be used for additional emission reduction program funding. ERC certificates, if used, will be surrendered prior to first turbine fire.

Verification: The project owner shall submit to the CPM confirmation that the appropriate quantity of Carl Moyer Project or other emission reduction program funding and/or ERCs have been provided prior to initiation of on-site construction activities for emission reduction program funding and at least 30 days prior to turbine first fire for ERCs. The project owner shall provide emission reduction project selection information to the CPM for review and approval at least 15 days prior to committing funds to each selected emission reduction project. The project owner shall provide confirmation that the level of emission reduction program funding will meet the emission reduction requirements of this condition.

DISTRICT FINAL DETERMINATION OF COMPLIANCE CONDITIONS (SDAPCD 2009)

District Application Number 985745
Power block Unit #6 consisting of one nominal 208 MW (219 MW with steam augmentation) natural-gas fired combined-cycle Siemens SGT6-PAC5000F combustion turbine generator, serial number to be determined, with an ultra low NOx (ULN) combustor, an evaporative inlet air cooler, a heat recovery steam generator with a selective catalytic reduction unit, an oxidation catalyst, and a steam turbine generator and associated air-cooled heat exchanger to condense the exhaust steam from the steam turbine.

District Application Number 985747
Power block Unit #7 consisting of one nominal 208 MW (219 MW with steam augmentation) natural-gas fired combined-cycle Siemens SGT6-PAC5000F combustion turbine generator, serial number to be determined, with an ultra low NOx (ULN) combustor, an evaporative inlet air cooler, a heat recovery steam generator with a selective catalytic reduction unit, an oxidation catalyst, and a steam turbine generator and associated air-cooled heat exchanger to condense the exhaust steam from the steam turbine.

GENERAL CONDITIONS

AQ-1 This equipment shall be properly maintained and kept in good operating condition at all times and, to the extent practicable, the project owner shall maintain and operate the equipment and any associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. [Rule 21 and 40 CFR §60.11]

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

AQ-2 The project owner shall operate the project in accordance with all data and specifications submitted with the application under which this license is issued and District Application Nos. 985745, 985747 and 985748. [Rule 14]

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

AQ-3 The project owner shall provide access, facilities, utilities, and any necessary safety equipment, with the exception of personal protective equipment requiring individual fitting and specialized training, for source testing and inspection upon request of the Air Pollution Control District. [Rule 19]

Verification: The project owner shall provide facilities, utilities, and safety equipment for source testing and inspections upon request of the District, ARB, and the Energy Commission.

AQ-4 The project owner shall obtain any necessary District permits for all ancillary combustion equipment including emergency engines, prior to on-site delivery of the equipment. [Rule 10]

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-5 Prior to the earlier of the initial startup dates for either of the two combustion turbines, the project owner shall surrender to the District Class A Emission Reduction Credits (ERCs) in an amount equivalent to 47.9 tons per year of oxides of nitrogen (NOx) to offset the net maximum allowable increase of 39.9 tons per year of NOx emissions for the two combustion turbines and the emergency fire pump engine described in District Application Nos. 985745, 985747, and 985748. [Rule 20.3(d)(8)]

Verification: The project owner shall submit to the CPM, within 15 days of ERC surrender to the District, information demonstrating compliance with this condition.

AQ-6 A rolling 12-calendar-month period is one of a series of successive consecutive 12-calendar-month periods. The initial 12-month-calendar period of such a series shall begin on the first day of the month in which the applicable beginning date for that series occurs as specified in this permit. [Rule 20.3 (d)(3), Rule 20.3(d)(8) and Rule 21].

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

AQ-7 Pursuant to 40 CFR §72.30(b)(2)(ii) of the Federal Acid Rain Program, the project owner shall submit an application for a Title IV Operating Permit at least 24 months prior to the initial startup of the combustion turbines. [40 CFR Part 72]

Verification: The project owner shall submit to the CPM copies of the acid rain permit application within five working days of its submittal by the project owner to the District.

AQ-8 The project owner shall comply with all applicable provisions of 40 CFR Part 73, including requirements to offset, hold and retire sulfur dioxide (SO_2) allowances. [40 CFR Part 73]

Verification: The project owner shall submit to the CPM and the District the CTG annual operating data and SO_2 allowance information demonstrating compliance with all applicable provisions of 40 CFR 73 as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-9 All records required by this permit shall be maintained on site for a minimum of five years and made available to the District upon request. [Rule 1421]

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

COMBUSTION TURBINE CONDITIONS

Definitions

AQ-10 For purposes of determining compliance with the emission limits of this permit, a shutdown period is the period of time that begins with the lowering of the gross electrical output (load) of the combustion turbine below 114 megawatts (MW) and that ends five minutes after fuel flow to the combustion turbine ceases, not to exceed 35 consecutive minutes. [Rule 20.3 (d)(1)]

Verification: The project owner shall submit to the CPM the CTG shutdown event duration data demonstrating compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-11 A startup period is the period of time that begins when fuel flows to the combustion turbine following a non-operational period. For purposes of determining compliance with the emission limits of this permit, the duration of a startup period shall not exceed 60 consecutive minutes. [Rule 20.3(d)(1)]

Verification: The project owner shall submit to the CPM the CTG startup event duration data demonstrating compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-12 A non-operational period is any five-consecutive-minute period when fuel does not flow to the combustion turbine. [Rule 20.3(d)(1)]

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

AQ-13 Tuning is defined as adjustments to the combustion or emission control system that involves operating the combustion turbine or emission control system in a manner such that the emissions control equipment may not be fully effective or operational. Only one gas turbine shall be tuned at any given time. Tuning events shall not exceed 720 unit operating minutes in a calendar day nor exceed 40 hours in a calendar year for each turbine. The District compliance division shall be notified at least 24 hours in advance of any tuning event. For purposes of this condition, the number of hours of tuning in a calendar year is defined as the total unit operating minutes of tuning during the calendar year divided by 60. [Rule 20.3(d)(1)]

Verification: The project owner shall notify the District and CPM at least 24 hours in advance of any tuning event. The project owner shall submit to the CPM the CTG operating data demonstrating compliance with tuning limitations identified in this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-14 A Continuous Emission Monitoring System (CEMS) protocol is a document approved in writing by the District that describes the methodology and quality assurance and quality control procedures for monitoring, calculating, and recording stack emissions from the combustion turbine that is monitored by the CEMS. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: The project owner shall maintain a copy of the CEMS protocol on site and provide it for inspection on request by representatives of the District, ARB, and the Energy Commission.

AQ-15 A transient hour is a clock hour during which the change in gross electrical output produced by the combustion turbine exceeds 50 MW per minute for one minute or longer during any period that is not part of a startup or shutdown period. [Rule 20.3(d)(1)]

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

AQ-16 For each combustion turbine, the commissioning period is the period of time commencing with the initial startup of that turbine and ending the sooner of 120 calendar days from the initial startup, after 415 hours of turbine operation, or the date the project owner notifies the District the commissioning period has ended. For purposes of this condition, the number of hours of turbine operation is defined as the total unit operating minutes during the commissioning period divided by 60. [Rule 20.3(d)(1)]

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

AQ-17 For each combustion turbine, the shakedown period is the period of time commencing with the initial startup that turbine and ending the sooner of 180 calendar days from the initial startup or the date the project owner notifies the District that the shakedown period has ended. [Rules 20.1(c)(16) and 21]

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

AQ-18 Turbine A is the combustion turbine as described on Applications No. 985745 or No, 98747, as applicable, that first completes its shakedown period. If both turbines complete their shakedown period on the same date, then Turbine A is the turbine described on Application No. 985745. [Rules 20.1(c)(16) and 21]

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

AQ-19 Turbine B is the combustion turbine as described on Application No. 985745 or No. 985747, as applicable, that last completes its shakedown period. If both turbines complete their shakedown period on the same date, then Turbine B is the turbine described on Application No. 985747. [Rules 20.1(c)(16) and 21]

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

AQ-20 Low load operation is a period of time that begins when the gross electrical output (load) of the combustion turbine is reduced below 114 MW and that ends 10 consecutive minutes after the combustion turbine load exceeds 114

MW, provided that fuel is continuously combusted during the entire period and one or more clock hour concentration emission limits specified in this permit are exceeded as a result of the low-load operation. For each combustion turbine, periods of operation at low load shall not exceed 130 unit operating minutes in any calendar day nor an aggregate of 780 unit operating minutes in any calendar year. No low load operation period shall begin during a startup period. [Rule 20.3(d)(1)]

Verification: The project owner shall submit to the CPM the engine operating data demonstrating compliance with this condition on request and shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-21 For each combustion turbine, a unit operating day, hour, and minute mean the following:

A. A unit operating day means any calendar day in which the turbine combusts fuel.

B. A unit operating hour means any clock hour in which the turbine combusts fuel.

C. A unit operating minute means any clock minute in which the turbine combusts fuel and any clock minute that is part of a shutdown period.

[Rule 21, 40 CFR Part 75, Rule 20.3(d)(1), 40 CFR Part 60 Subpart KKKK]

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

General Conditions

AQ-22 The exhaust stacks for each combustion turbine shall be at least 139 feet in height above site base elevation. [Rules 20.3(d)(2) and 1200]

Verification: The project owner shall submit to the CPM for review the exhaust stack specification at least 60 days before the installation of the stack.

AQ-23 The combustion turbines shall be fired on Public Utility Commission (PUC) quality natural gas. The project owner shall maintain, on site, quarterly records of the natural gas sulfur content (grains of sulfur compounds per 100 dscf of natural gas) and hourly records of the higher and lower heating values (btu/scf) of the natural gas; and provide records to District personnel upon request. [Rule 20.3(d)(1)]

Verification: The project owner shall submit the quarterly fuel sulfur content values in the in the Quarterly Operation Reports **(AQ-SC8)** and make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-24 Unless otherwise specified in this permit, all continuous monitoring data shall be collected at least once every minute. [Rules 69.3, 69.3.1, and 20.3(d)(1)]

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

Emission Limits

AQ-25 For purposes of determining compliance with emission limits based on source testing, the average of three subtests shall be used. For purposes of determining compliance with emission limits based on a Continuous Emission Monitoring System (CEMS), data collected in accordance with the CEMS protocol shall be used and the averages for averaging periods specified herein shall be calculated as specified in the CEMS protocol. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: Source tests demonstrating compliance with this condition shall be provided to the CPM and are due within the timeframes specified in Conditions **AQ-53** and **AQ-54**. CEMS data summaries shall be submitted to the CPM as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-26 For purposes of determining compliance with emission limits based on CEMS data, all CEMS calculations, averages, and aggregates shall be performed in accordance with the CEMS protocol approved in writing by the District. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: CEMS data summaries shall be submitted to the CPM as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-27 For each emission limit expressed as pounds, pounds per hour, or parts per million based on a one-hour or less averaging period or compliance period, compliance shall be based on using data collected at least once every minute when compliance is based on CEMS data. [Rules 69.3, 69.3.1, and 20.3(d)(1)]

Verification: CEMS data summaries shall be submitted to the CPM as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-28 When a combustion turbine is combusting fuel (operating), the emission concentration of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2), shall not exceed 2.0 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. For purposes of determining compliance based on CEMS data, the following averaging periods calculated in accordance with the CEMS protocol shall apply:

a. For any transient hour, a 3-clock hour average, calculated as the average of the transient hour, the clock hour immediately prior to the transient hour and the clock hour immediately following the transient hour.

b. For all other hours, a 1-clock hour average.

[Rule 20.3(d)(1)]

Verification: The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-29 When a combustion turbine is operating, the emission concentration of carbon monoxide (CO) shall not exceed 2.0 ppmvd corrected to 15 % oxygen, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. For purposes of determining compliance based on CEMS data, the following averaging periods calculated in accordance with the CEMS protocol shall apply;

a. For any transient hour, a 3-clock-hour average, calculated as the average of the transient hour, the clock hour immediately prior to the transient hour and the clock hour immediately following the transient hour.

b. For all other hours, a 1-clock-hour average.

[Rule 20.3(d)(1)]

Verification: The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-30 When a combustion turbine is operating, the volatile organic compound (VOC) concentration, calculated as methane, measured in the exhaust stack, shall not exceed 1.5 ppmvd corrected to 15% oxygen, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. For purposes of determining compliance based on the CEMS, the District approved CO/VOC surrogate relationship, the CO CEMS data, and the following averaging periods calculated in accordance with the CEMS protocol shall be used:.

a. For any transient hour, a 3-clock-hour average, calculated as the average of the transient hour, the clock hour immediately prior to the transient hour and the clock hour immediately following the transient hour.

b. For all other hours, a 1-clock-hour average.

The CO/VOC surrogate relationship shall be verified and/or modified, if necessary, based on source testing. [Rule 20.3(d)(1)]

Verification: The project owner shall provide the CEMS data, using the appropriate CO/VOC surrogate relationship, to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-31 When a combustion turbine is operating, the ammonia concentration (ammonia slip), shall not exceed 5.0 ppmvd corrected to 15 % oxygen, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. [Rule 1200]

Verification: The project owner shall provide the estimated ammonia concentrations and ammonia emissions based on the annual source test data, the CEMS data and

SCR ammonia flow data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8).**

AQ-32 When a combustion turbine is operating with post-combustion air pollution control equipment that controls oxides of nitrogen (NOx) emissions, the emission concentration NOx, calculated as nitrogen dioxide (NO_2), shall not exceed 12.9 ppmvd calculated over each clock hour period and corrected to 15% oxygen, except for periods of startup and shutdown, as defined in Rule 69.3.1. This limit does not apply during any period in which the facility is subject to a variance from the emission limits contained in Rule 69.3.1. [Rule 69.3.1]

Verification: The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-33 When a combustion turbine is operating without any post-combustion air pollution control equipment that controls oxides of nitrogen (NOx) emissions, the emission concentration of NOx calculated as nitrogen dioxide (NO_2) from each turbine shall not exceed 21.6 parts per million by volume on a dry basis (ppmvd) calculated over each clock hour period and corrected to 15% oxygen, except for periods of startup and shutdown, as defined in Rule 69.3.1. This limit does not apply during any period in which the facility is subject to a variance from the emission limits contained in Rule 69.3.1. [Rule 69.3.1]

Verification: The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-34 When a combustion turbine is operating, the emission concentration of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2) shall not exceed 42 ppmvd calculated over each clock hour period and corrected to 15% oxygen, on a dry basis, except during periods of startup and shutdown, as defined in Rule 69.3. This limit does not apply during any period in which the facility is subject to a variance from the emission limits contained in Rule 69.3. [Rule 69.3]

Verification: The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-35 For each rolling 30-day-unit-operating-day period, average emission concentration of oxides of nitrogen (NOx) for each turbine calculated as nitrogen dioxide (NO_2) in parts per million by volume dry (ppmvd) corrected to 15% oxygen or, alternatively, as elected by the project owner, the average NOx emission rate in pounds per megawatt-hour (lb/MWh) shall not exceed an average emission limit calculate in accordance with 40 CFR Section 60.3480(b)(3). The emission concentration and emission rate averages shall be calculated in accordance with 40 CFR Section 60.4380(b)(1). The average emission concentration limit and emission rate limit shall be based on an average of hourly emission limits over the 30-day-unit-operating-day period. The hourly emission concentration limit and emission rate limit shall be15 ppmvd corrected to 15% oxygen and 0.43 lb/MWh, respectively, for clock

hours when the combustion turbine load is equal to or greater than 156 megawatts at all times during the clock hour, respectively, and 96 ppmvd corrected to 15% oxygen and 4.7 lb/MWh for all other clock hours when the combustion turbine is operating, respectively. The average shall exclude all clock hours occurring before the Initial Source Test but shall include emissions during all other times that the equipment is operating including, but not limited to, emissions during low load operation, startup, shutdown, and tuning periods. For each six-calendar-month period, emissions in excess of these limits and monitor downtime shall be identified in accordance with 40 CFR Sections 60.4350 and 60.4380(b)(2), except that Section 60.4350(c) shall not apply for identifying periods in excess of a NOx concentration limit, and reported to the District and the federal EPA in accordance with Title V Operating Permit No. 974488. [40 CFR Part 60 Subpart KKKK]

Verification: The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-36 The emissions of particulate matter less than or equal to 10 microns in diameter (PM10) shall not exceed 9.5 pounds per hour for each combustion turbine. [Rule 20.3(d)(2)]

Verification: Source tests demonstrating compliance with this condition shall be provided to the CPM and are due within the timeframes specified in Conditions **AQ-53** and **AQ-54**.

AQ-37 The discharge of particulate matter from the exhaust stack of each combustion turbine shall not exceed 0.10 grains per dry standard cubic foot (0.23 grams/dscm). The District may require periodic testing to verify compliance with this standard. [Rule 53]

Verification: Source tests demonstrating compliance with this condition shall be provided to the CPM and are due within the timeframes specified in Conditions **AQ-53** and **AQ-54**.

AQ-38 Visible emissions from the lube oil vents and the exhaust stack of each combustion turbine shall not exceed 20% opacity for more than three (3) minutes in any period of 60 consecutive minutes. [Rule 50]

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

AQ-39 Mass emissions from each combustion turbine of oxides of nitrogen (NOx), calculated as NO_2; carbon monoxide (CO); and volatile organic compounds (VOC), calculated as methane, shall not exceed the following limits, except during commissioning, low load operation, startup, shutdown, or tuning periods for that turbine. A 1-clock-hour averaging period for these limits shall apply to CEMS data except for emissions during transient hours when a 3-clock-hour averaging period shall apply. [Rule 20.3(d)(2)]

Pollutant	*Emission Limit, lb*
a. NOx	*15.1*
b. CO	*9.2*
c. VOC	*4.0*

Verification: The project owner shall submit to the CPM operating data demonstrating compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-40 Excluding any minutes that are coincident with a shutdown period, cumulative mass emissions of oxides of nitrogen (NOx), calculated as NO_2; carbon monoxide (CO); and volatile organic compounds (VOC), calculated as methane, during a combustion turbine's startup period shall not exceed the following limits during any startup period, except during that turbine's commissioning period. [Rule 20.3(d)(1)]

Pollutant	*Emission Limit,lb*
a. NOx	*69.2*
b. CO	*545*
c. VOC	*15.5*

Verification: The project owner shall submit to the CPM operating data demonstrating compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-41 Cumulative mass emissions of oxides of nitrogen (NOx), calculated as NO_2; carbon monoxide (CO); and volatile organic compounds (VOC), calculated as methane, during a combustion turbine's shutdown period shall not exceed the following limits during any shutdown period, except during that turbine's commissioning period. [Rule 20.3(d)(1)]

Pollutant	*Emission Limit,lb*
a. NOx	*25.7*
b. CO	*277*
c. VOC	*6.2*

Verification: The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-42 The oxides of nitrogen (NOx) emissions from each combustion turbine shall not exceed 200 pounds per hour and total aggregate NOx emissions from both combustion turbines combined shall not exceed 286 pounds per hour, calculated as nitrogen dioxide and measured over each 1-clock hour period. These emission limits shall apply during all times one or both turbines are

operating, including, but not limited to, emissions during commissioning, low load operation, startup, shutdown, and tuning periods. [Rule 20.3(d)(2)]

Verification: The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-43 The carbon monoxide (CO) emissions from each combustion turbine shall not exceed 3813 pounds per hour and total aggregate CO emissions from both combustion turbines combined shall not exceed 4627 pounds per hour measured over each 1-clock hour period. This emission limit shall apply during all times that one or both turbines are operating, including, but not limited to emissions during commissioning, low load operation, startup, shutdown, and tuning periods. [Rule 20.3(d)(2)]

Verification: The project owner shall provide CEMS emissions data to demonstrate compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**.

AQ-44 Beginning with the initial startup dates for either combustion turbine, aggregate emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2); carbon monoxide (CO); volatile organic compounds (VOCs), calculated as methane; particulate matter less than or equal to 10 microns in diameter (PM10); and oxides of sulfur (SOx), calculated as sulfur dioxide (SO_2), from the combustion turbines described in District Applications No. 985745 and 985747 and the emergency fire pump described in Application No. 985748, except emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1), shall not exceed the following limits for each rolling 12-calendar-month period:

Pollutant	*Emission Limit, tons per year*
a. NOx	*72.11*
b. CO	*339.9*
c. VOC	*23.7*
d. PM10	*39.0*
e. SOx (calculated as SO_2)	*5.6*

In addition, beginning with the date on which both turbines have completed their commissioning periods aggregate emissions of CO and VOC from the equipment specified above in this condition shall not exceed 217.3 and 20.1 tons per year, respectively, for each rolling 12-calendar-month period.

The aggregate emissions of each pollutant shall include emissions during all times that the equipment is operating including, but not limited to, emissions during commissioning, low load operation, startup, shutdown, and tuning periods. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

Verification: The project owner shall submit to the CPM and the District the facility annual operating and emissions data demonstrating compliance with this condition as part of the fourth quarter's Quarterly Operation Reports **(AQ-SC8)**.

AQ-45 For each calendar month, the project owner shall maintain records, as applicable, on a calendar monthly basis, of mass emissions during the calendar month of NOx (calculated as NO_2), CO, VOCs (calculated as methane), PM10, and SOx (calculated as SO_2), in tons, from each emission unit described in District Applications No. 985745, 985747, and 985748 , except for emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1). These records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

Verification: The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-46 For each calendar month and each rolling 12-calendar-month period, the project owner shall maintain records as applicable, on a calendar monthly basis, of aggregate mass emissions of NOx (calculated as NO_2), CO, VOCs (calculated as methane), PM10, and SOx (calculated as SO_2) in tons for the emission units described in District Applications No. 985745, 985747, and 985748, except for emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1). These records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

Verification: The project owner shall provide emissions summary data in compliance with this condition as part of the Quarterly Operation Reports **(AQ-SC8)**. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-47 For each combustion turbine, the number of startup periods occurring in each calendar year shall not exceed 1460. [Rules 1200 and 21]

Verification: The project owner shall submit facility annual operating data demonstrating compliance with this condition as part of the fourth quarter's Quarterly Operation Reports **(AQ-SC8).**

Ammonia – SCR

AQ-48 Not later than 90 calendar days prior to the start of construction, the project owner shall submit to the District the final selection, design parameters and details of the selective catalytic reduction (SCR) and oxidation catalyst emission control systems for the combustion turbines including, but not limited to, the minimum ammonia injection temperature for the SCR; the catalyst volume, space velocity and area velocity at full load with and without steam injection; and control efficiencies of the SCR and the oxidation catalyst CO at temperatures between 100 °F and 1000 °F at space velocities

corresponding to 100% (with steam injection) and 60% load. Such information may be submitted to the District as trade secret and confidential pursuant to District Rules 175 and 176. [Rules 20.3(d)(1) and 14]

Verification: The project owner shall submit to the CPM for review and District for approval final selection, design parameters and details of the SCR and oxidation catalyst emission control systems at least 90 days prior to the start of construction.

AQ-49 When a combustion turbine is operating, ammonia shall be injected at all times that the associated selective catalytic reduction (SCR) system outlet temperature is 450 degrees Fahrenheit or greater. [Rule 20.3 (d)(1)]

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

AQ-50 Continuous monitors shall be installed on each SCR system prior to their initial operation to monitor or calculate, and record the ammonia solution injection rate in pounds per hour and the SCR outlet temperature in degrees Fahrenheit for each unit operating minute. The monitors shall be installed, calibrated and maintained in accordance with a District approved protocol, which may be part of the CEMS protocol. This protocol, which shall include the calculation methodology, shall be submitted to the District for written approval at least 90 days prior to initial startup of the gas turbines with the SCR system. The monitors shall be in full operation at all times when the turbine is in operation. [Rule 20.3(d)(1)]

Verification: The project owner shall submit to the CPM for review and the District for approval a turbine operation monitoring protocol in compliance with this condition at least 90 days prior to the initial startup.

AQ-51 Except during periods when the ammonia injection system is being tuned or one or more ammonia injection systems is in manual control for compliance with applicable permit conditions, the automatic ammonia injection system serving the SCR system shall be in operation in accordance with manufacturer's specifications at all times when ammonia is being injected into the SCR system. Manufacturer specifications shall be maintained on site and made available to District personnel upon request. [Rule 20.3(d)(1)]

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

AQ-52 The concentration of ammonia solution used in the ammonia injection system shall be less than 20% ammonia by weight. Records of ammonia solution concentration shall be maintained on site and made available to District personnel upon request. [Rule 14]

Verification: The project owner shall maintain on site and provide on request of the CPM or District the ammonia delivery records that demonstrate compliance with this condition.

Testing

AQ-53 All source test or other tests required by this permit/license shall be performed by the District or an independent contractor approved by the District. Unless otherwise specified in this permit or authorized in writing by the District, if testing will be performed by an independent contractor and witnessed by the District, a proposed test protocol shall be submitted to the District for written approval at least 60 days prior to source testing. Additionally, the District shall be notified a minimum of 30 days prior to the test so that observers may be present unless otherwise authorized in writing by the District. [Rules 20.3(d)(1) and 1200 and 40 CFR Part60 Subpart KKKK and 40 CFR §60.8]

Verification: The project owner shall submit to the CPM for review and the District for approval the initial source test protocol at least 60 days prior to the initial source test. The project owner shall notify the CPM and District no later than 30 days prior to the proposed source test date and time.

AQ-54 Unless otherwise specified in this permit or authorized in writing by the District, within 45 days after completion of a source test or RATA performed by an independent contractor, a final test report shall be submitted to the District for review and approval. [Rules 20.3(d)(1) and 1200 and 40 CFR Part 60 Subpart KKKK, 40 CFR §60.8, and 40 CFR Part 75]

Verification: The project owner will submit all RATA or source test reports to the CPM for review and the District for approval within 45 days of the completion of those tests.

AQ-55 The exhaust stacks for each combustion turbine shall be equipped with source test ports and platforms to allow for the measurement and collection of stack gas samples consistent with all approved test protocols. The ports and platforms shall be constructed in accordance with District Method 3A, Figure 2, and approved by the District. Ninety days prior to construction of the turbine stacks the project owner shall provide the District for written approval detailed plan drawings of the turbine stacks that show the sampling ports and demonstrate compliance with the requirements of this condition. [Rule 20]

Verification: The project owner shall submit to the CPM for review and District for approval a stack test port and platform plan at least 60 days before the installation of the stack ports and platform.

AQ-56 Not later than 60 calendar days after completion of the commissioning period for each combustion turbine, an Initial Emissions Source Test shall be conducted on that turbine to demonstrate compliance with the NOx, CO, VOC, PM10, and ammonia emission standards of this permit. The source test protocol shall comply with all of the following requirements:

a. Measurements of NOx, CO concentrations and emissions and oxygen (O_2) concentration shall be conducted in accordance with U.S. Environmental Protection Agency (EPA) methods 7E, 10, and 3A,

respectively, and District source test Method 100, or alternative methods approved by the District and EPA;

b. Measurement of VOC emissions shall be conducted in accordance with EPA Methods 25A and/or 18, or alternative methods approved by the District and EPA;

c. Measurements of ammonia emissions shall be conducted in accordance with Bay Area Air Quality Management District Method ST-1B or an alternative method approved by the District and EPA;

d. Measurements of PM10 emissions shall be conducted in accordance with EPA Methods 201A and 202 or alternative methods approved by the district and EPA;

e. Source testing shall be performed at the normal load level, as specified in 40 CFR Part 75 Appendix A Section 6.5.2.1 (d), provided it is not less than 80% of the combustion turbine's rated load unless it is demonstrated to the satisfaction of the District that the combustion turbine cannot operate under these conditions . If the demonstration is accepted, then emissions source testing shall be performed at the highest achievable continuous power level. The District may specify additional testing at different load levels or operational conditions to ensure compliance with the emission limits of this permit and District Rules and Regulations;

f. Measurements of particulate matter emissions shall be conducted in accordance with SDAPCD Method 5 or an alternative method approved by the District and EPA; and

g. Measurements of opacity shall be conducted in accordance with EPA Method 9 or an alternative method approved by the District and EPA.

h. Unless otherwise authorized in writing by the District, testing for NOx, CO, VOC, PM10 and ammonia concentrations and emissions, as applicable, shall be conducted concurrently with the NOx and CO continuous emission measurement system (CEMS) Relative Accuracy Test Audit (RATA).

[Rule 20.3(d)(1) and 1200]

Verification: The project owner shall submit to the CPM for review and the District for approval the initial source test protocol and source test report within the timeframes specified in Conditions **AQ-53** and **AQ-54**.

AQ-57 A renewal source test and a NOx and CO Relative Accuracy Test Audit (RATA) test shall be periodically conducted on each combustion turbine to demonstrate compliance with the NOx, CO, VOC, PM10, and ammonia emission standards of this permit and applicable relative accuracy requirements for the CEMS systems using District approved methods. The renewal source test and the NOx and CO RATAs shall be conducted in accordance with the applicable RATA frequency requirements of 40 CFR75, Appendix B, Sections 2.3.1 and 2.3.3. The renewal source test shall be conducted in accordance with a protocol complying with all the applicable

requirements of the source test protocol for the Initial Emissions Source Test. [Rule 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: The project owner shall submit to the CPM for review and the District for approval the periodic RATA and source test protocols, and RATA source test reports within the timeframes specified in Conditions **AQ-53** and **AQ-54**.

AQ-58 Relative Accuracy Test Audit (RATAs) and all other required certification tests shall be performed and completed on the NOx CEMS in accordance with applicable provisions of 40 CFR Part 75 Appendix A and B and 40 CFR §60.4405 and on the CO CEMS in accordance with applicable provisions of 40 CFR Part 60 Appendix B and F. [Rule 21, Rule 20.3 (d)(1), 40 CFR Part 60 Subpart KKKK and 40 CFR Part 75]

Verification: The results and field data collected during source tests required by this condition shall be submitted to the CPM for review and the District for approval as required by Condition **AQ-54**.

AQ-59 Not later than 60 calendar days after completion of the commissioning period for each combustion turbine, an initial emission source test for toxic air contaminants shall be conducted on that turbine to determine the emissions of toxic air contaminants from the combustion turbines. At a minimum the following compounds shall be tested for, and emissions, if any, quantified:

a. Acetaldehyde
b. Acrolein
c. Benzene
d. Formaldehyde
e. Toluene
f. Xylenes

This list of compounds may be adjusted by the District based on source test results to ensure compliance with District Rule 1200 is demonstrated. The District may require one or more or additional compounds to be quantified through source testing as needed to ensure compliance with Rule 1200. Within 60 calendar days after completion of a source test performed by an independent contractor, a final test report shall be submitted to the District for review and approval. [Rule 1200]

Verification: The results and field data collected during source tests required by this condition shall be submitted to the CPM for review and the District for approval within 60 days of testing.

AQ-60 The District may require one or more of the following compounds, or additional compounds to be quantified through source testing periodically to ensure compliance with rule 1200:

a. Acetaldehyde

b. Acrolein

c. Benzene

d. Formaldehyde

e. Toluene

f. Xylenes

If the District requires the project owner to perform this source testing, the District shall request the testing in writing a reasonable period of time prior to the testing date. [Rule 1200]

Verification: The results and field data collected during source tests required by the District under this condition shall be submitted to the CPM for review and the District for approval within 60 days of testing.

AQ-61 The higher heating value of the combustion turbine fuel shall be measured by ASTM D1826–94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter or ASTM D1945–96, Standard Method for Analysis of Natural Gas by Gas Chromatography or an alternative test method approved by the District and EPA. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

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

AQ-62 The sulfur content of the combustion turbine fuel shall be sampled not less than once each calendar quarter in accordance with a protocol approved by the District, which shall be submitted to the District for approval not later than 90 days before the earlier of the initial startup dates for either of the two combustion turbines and measured with ASTM D1072–90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases; ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry; ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry; ASTM D6228–98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection; or ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence or an alternative test method approved by the District and EPA. [Rule 20.3 (d)(1), Rule 21, and 40 CFR Part 75]

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

Continuous Monitoring

AQ-63 The project owner shall comply with the applicable continuous emission monitoring requirements of 40 CFR Part 75. [40 CFR Part 75]

Verification: The project owner shall maintain a copy of the CEMS protocol required by **AQ-64** on site and provide it, other CEMS data, and the CEMS for inspection on request by representatives of the District, ARB, and the Energy Commission.

AQ-64 A continuous emission monitoring system (CEMS) shall be installed on each combustion turbine and properly maintained and calibrated to measure, calculate and record the following, in accordance with the District approved CEMS protocol:

A. Hourly average(s) concentration of oxides of nitrogen (NOX) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the NOx limits of this permit;

B. Hourly average concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the CO limits of this permit;

C. Percent oxygen (O_2) in the exhaust gas for each unit operating minute;

D. Average concentration of oxides of nitrogen (NOx) for each continuous rolling 3-hour period, in parts per million (ppmv) corrected to 15% oxygen;

E. Hourly mass emissions of oxides of nitrogen (NOx), in pounds;

F. Cumulative mass emissions of oxides of nitrogen (NOx) in each startup and shutdown period, in pounds;

G. Daily mass emissions of oxides of nitrogen (NOx), in pounds;

H. Calendar monthly mass emissions of oxides of nitrogen (NOx), in pounds;

I. Rolling 30-unit-operating-day average concentration of oxides of nitrogen (NOx) corrected to 15% oxygen, in parts per million (ppmvd);

J. Rolling 30-unit-operating-day average oxides of nitrogen (NOx) emission rate, in pounds per megawatt-hour (MWh).

K. Calendar quarter, calendar year, and rolling 12-calendar-month period mass emissions of oxides of nitrogen (NOx), in tons;

L. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds

M. Hourly mass emissions of carbon monoxide (CO), in pounds;

N. Daily mass emission of carbon monoxide (CO), in pounds;

O. Calendar monthly mass emission of carbon monoxide (CO), in pounds;

P. Rolling 12-calendar-month period mass emission of carbon monoxide (CO), in tons;

Q. Average concentration of oxides of nitrogen (NOx) and carbon monoxide (CO) uncorrected and corrected to 15 percent oxygen, in parts per million (ppmvd), during each unit operating minute;

R. Average emission rate in pounds per hour of oxides of nitrogen (NOx) and carbon monoxide (CO) during each unit operating minute.

[Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: The project owner shall submit to the CPM for review and the District for approval a CEMS protocol, as required by **AQ-64**, which includes description of the methods of compliance with the requirements of this condition. The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-65 No later than 90 calendar days prior to initial startup of each combustion turbine, the project owner shall submit a CEMS protocol to the District, for written approval that shows how the CEMS will be able to meet all District monitoring requirements. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: The project owner shall submit to the CPM for review and the District for approval a CEMS operating protocol at least 90 days prior to the operation the CEMS.

AQ-66 No later than the earlier of 90 unit operating days or 180 calendar days after each combustion turbine commences commercial operation, a Relative Accuracy Test Audit (RATA) and other required certification tests shall be performed an completed on the that turbine's NOx CEMS in accordance with 40 CFR Part 75 Appendix A and on the CO CEMS in accordance with 40 CFR Part 60 Appendix B. The RATAs shall demonstrate that the NOx and CO CEMS comply with the applicable relative accuracy requirements. At least 60 calendar days prior to the test date, the project owner shall submit a test protocol to the District for written approval. Additionally, the District and U.S. EPA shall be notified a minimum of 45 calendar days prior to the test so that observers may be present. Within 45 calendar days of completion of this test, a written test report shall be submitted to the District for approval. For purposes of this condition, commences commercial operation is defined as the first instance when power is sold to the electrical grid. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: The project owner shall submit to the CPM for review and the District for approval the RATA certification test protocol at least 60 days prior to the RATA test and shall notify the CPM and District of the RATA test date at least 45 days prior to conducting the RATA and other certification tests. The project owner will submit all RATA or source test reports to the CPM for review and the District for approval within 45 days of the completion of those tests.

AQ-67 A monitoring plan in conformance with 40 CFR 75.53 shall be submitted to U.S EPA Region 9 and the District at least 45 calendar days prior to the

Relative Accuracy Test Audit (RATA), as required in 40 CFR 75.62. [40 CFR Part 75]

Verification: The project owner shall submit to the CPM for review and the District for approval a monitoring plan in compliance with this condition at least 45 days prior to the RATA test.

AQ-68 The oxides of nitrogen (NOx) and oxygen (O_2) components of the CEMS shall be certified and maintained in accordance with applicable Federal Regulations including the requirements of sections 75.10 and 75.12 of title 40, Code of Federal Regulations Part 75 (40 CFR 75), the performance specifications of Appendix A of 40 CFR 75, the quality assurance procedures of Appendix B of 40 CFR 75 and the CEMS protocol approved by the District. The carbon monoxide (CO) components of the CEMS shall be certified and maintained in accordance with 40 CFR 60, Appendices B and F, unless otherwise specified in this permit, and the CEMS protocol approved by the District. [Rule 69.3, 69.3.1 and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: The project owner shall submit to the CPM for review and the District for approval a CEMS protocol, as required by **AQ-64**, which includes description of the methods of compliance with the requirements of this condition. The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-69 The CEMS shall be in operation in accordance with the District approved CEMs protocol at all times when the turbine is in operation a copy of the District approved CEMS monitoring protocol shall be maintained on site and made available to District personnel upon request. [Rules 69.3, 69.3.1, and 20(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

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

AQ-70 When the CEMS is not recording data and the combustion turbine is operating, hourly NOx emissions for purposes of calendar year and rolling 12-calendar-month period emission calculations shall be determined in accordance with 40 CFR 75 Subpart C. Additionally, hourly CO emissions for rolling 12-calendar-month period emission calculations shall be determined using CO emission factors to be determined from source test emission factors, recorded CEMS data, and fuel consumption data, in terms of pounds per hour of CO for the gas turbine. Emission calculations used to determine hourly emission rates shall be reviewed and approved by the District, in writing, before the hourly emission rates are incorporated into the CEMS emission data. [Rules 20.3(d)(3) and 21 and 40 CFR Part 75]

Verification: The project owner shall provide the District for approval and the CPM for review all emission calculations required by this condition, in a manner and time required by the District, and shall provide notation of when such calculations are used in place of operating CEMS data in the Quarterly Operation Reports **(AQ-SC8)**.

AQ-71 Any violation of any emission standard as indicated by the CEMS shall be reported to the District's compliance division within 96 hours after such occurrence. [Rule 19.2]

Verification: The project owner shall notify the District regarding any emission standard violation as required in this condition and shall document all such occurrences in each Quarterly Operation Report **(AQ-SC8)**.

AQ-72 The CEMS shall be maintained and operated, and reports submitted, in accordance with the requirements of rule 19.2 Sections (d), (e), (f) (1), (f) (2), (f) (3), (f) (4) and (f) (5), and a CEMS protocol approved by the District. [Rule 19.2]

Verification: The project owner shall submit to the District the CEMS reports as required in this condition and shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-73 Except for changes that are specified in the initial approved CEMS protocol or a subsequent revision to that protocol that is approved in advance, in writing by the District, the District shall be notified in writing at least thirty (30) calendar days prior to any planned changes made in the CEMS or Data Acquisition and Handling System (DAHS), including, but not limited to, the programmable logic controller, software which affects the value of data displayed on the CEMS / DAHS monitors with respect to the parameters measured by their respective sensing devices or any planned changes to the software that controls the ammonia flow to the SCR. Unplanned or emergency changes shall be reported within 96 hours. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: The project owner shall submit to the CPM for review and the District for approval any revision to the CEMS/DAHS or ammonia flow control software, as required by this condition, to be approved in advance at least 30 days before any planned changes are made. The project owner shall notify the District regarding any unplanned emergency changes to these software systems within 96 hours and shall document all such occurrences in each Quarterly Operation Report **(AQ-SC8)**.

AQ-74 At least 90 calendar days prior to the Initial Emissions Source Test, the project owner shall submit a monitoring protocol to the District for written approval which shall specify a method of determining the CO/VOC surrogate relationship that shall be used to demonstrate compliance with all VOC emission limits. This protocol can be provided as part of the Initial Source Emissions Testing Protocol. [Rule 20.3 (d)(1)]

Verification: The project owner shall submit to the CPM for review and the District for approval the monitoring protocol as part of the initial source test protocol in compliance with requirements of this condition at least 90 days prior to the initial source test.

AQ-75 Fuel flowmeters shall be installed and maintained to measure the fuel flow rate, corrected for temperature and pressure, to each combustion turbine. Correction factors and constants shall be maintained on site and made

available to the District upon request. The fuel flowmeters shall meet the applicable quality assurance requirements of 40 CFR Part 75, Appendix D, and Section 2.1.6. [Rule 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Park 60 Subpart KKKK, and 40 CFR Part75]

Verification: The project owner shall submit to the CPM the natural gas usage data from the fuel flow meters as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-76 Each combustion turbine shall be equipped with continuous monitors to measure, calculate and record unit operating days and hours and the following operational characteristics:

A. Date and time;

B. Natural gas flow rate to the combustion turbine during each unit operating minute, in standard cubic feet per hour;

C. Total heat input to the combustion turbine based the fuels higher heating value during each unit operating minute, in million British thermal units per hour (MMBtu/hr);

D. Higher heating value of the fuel on an hourly basis, in million British thermal units per standard cubic foot (MMBtu/scf);

E. Stack exhaust gas temperature during each unit operating minute, in degrees Fahrenheit;

F. Combustion turbine energy output during each unit operating minute in megawatts hours (MWh); and

G. Steam turbine energy output during each unit operating minute in megawatts hours (MWh).

The values of these operational characteristics shall be recorded each unit operating minute. The monitors shall be installed, calibrated, and maintained in accordance with a turbine operation monitoring protocol, which may be part of the CEMS protocol, approved by the District, which shall include any relevant calculation methodologies. The monitors shall be in full operation at all times when the combustion turbine is in operation. Calibration records for the continuous monitors shall be maintained on site and made available to the District upon request. [Rules 69.3, 69.3.1, and 20.(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Verification: The project owner shall submit to the CPM for review and the District for approval a turbine operation monitoring protocol in compliance with this condition and within the timeframes specified in **AQ-77** and the project owner shall make the site available for inspection of records and equipment required in this condition by representatives of the District, ARB, and the Energy Commission.

AQ-77 At least 90 calendar days prior to initial startup of the each combustion turbine, the project owner shall submit a turbine monitoring protocol to the District for written approval. This may be part of the CEMS protocol. [Rule

69.3, 69.3.1, and 20.3 (d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part75]

Verification: The project owner shall submit to the CPM for review and the District for approval a turbine monitoring protocol in compliance with this condition at least 90 days prior to the initial startup of each combustion turbine.

AQ-78 Operating logs or Data Acquisition and Handling System (DAHS) records shall be maintained to record the beginning and end times and durations of all startups, shutdowns, and tuning periods to the nearest minute, quantity of fuel used in each clock hour, calendar month, and 12-calendar-month period in standard cubic feet; hours of operation each day; and hours of operation during each calendar year. For purposes of this condition, the hours of turbine operation is defined as the total minutes the turbine is combusting fuel during the calendar year divided by 60. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

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

Commissioning and Shakedown

AQ-79 Before the end of the commissioning period for each combustion turbine, the project owner shall install post-combustion air pollution control equipment on that turbine to minimize NOx and CO emissions. Once installed, the post-combustion air pollution control equipment shall be maintained in good condition and shall be in full operation at all times when the turbine is combusting fuel and the air pollution control equipment is at or above its minimum operating temperature. [Rule 20.3(d)(1)]

Verification: The project owner shall provide the CPM District records demonstrating compliance with this condition as part of the monthly commissioning status report **(AQ-80)**.

AQ-80 Thirty calendar days after the end of the commissioning period for each combustion turbine, the project owner shall submit a written progress report to the District. This report shall include, at a minimum, the date the commissioning period ended, the periods of startup and shutdown, the emissions of NOx and CO during startup and shutdown, and the emissions of NOx and CO during steady state operation. This report shall also detail any turbine or emission control equipment malfunction, upset, repairs, maintenance, modifications, or replacements affecting emissions of air contaminants that occurred during the commissioning period. All of the following continuous monitoring information shall be reported for each minute and, except for cumulative mass emissions, averaged over each hour of operation:

A. Concentration of oxides of nitrogen (NOx) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);

B. Concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);

C. Percent oxygen (O_2) in the exhaust gas;

D. Mass emissions of oxides of nitrogen (NOx), in pounds;

E. Cumulative mass emissions of oxides of nitrogen (NOx) in each startup and shutdown period, in pounds;

F. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds

G. Mass emissions of carbon monoxide (CO), in pounds;

H. Total heat input to the combustion turbine based on the fuel's higher heating value, in million British thermal units per hour (MMBtu/hr);

I. Higher heating value of the fuel on an hourly basis, in million British thermal units per standard cubic foot (MMBtu/scf);

J. Gross electrical power output of the turbine, in megawatts hours (MWh) for each hour; and

K. SCR outlet temperature, in degrees Fahrenheit; and

L. Stack exhaust gas temperature, in degrees Fahrenheit.

The hourly average information shall be submitted in writing and in an electronic format approved by the District. The minute-by-minute information shall be submitted in an electronic format approved by the District. [Rules 69.3, 69.3.1, 20.3(d)(1) and 20.3(d)(2)]

Verification: A log of the dates, times, and cumulative unit operating hours when fuel is being combusted during the commissioning period shall be maintained by the project owner. The project owner shall submit, commencing one month from the time of gas turbine first fire, a monthly commissioning status report throughout the duration of the commissioning phase that demonstrates compliance with the requirements listed in this condition. The monthly commissioning status report shall be submitted to the CPM by the 10th of each month for the previous month, for all months with turbine commissioning activities following the turbine first fire date. The project owner shall also provide the reporting required by this condition to the District and CPM within 30 day of completing commissioning of each turbine. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-81 The three utility boilers described on District Permits to Operate No. 791, 792, and 793 shall not operate at any time one or both combustion turbines are operating. [Rules 20.3(d)(3), 20.3(d)(8) and 21 and 40 CFR §52.1]

Verification: The project owner shall submit to the CPM and the District the facility operating and emissions data demonstrating compliance with this condition, while the boilers regulated by this condition are still operational, as part of the monthly commissioning status report (**AQ-80**).

AQ-82 Beginning with the initial startup of Turbine A, aggregate emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2); carbon monoxide (CO); volatile organic compounds (VOCs), calculated as methane; particulate matter less than or equal to 10 microns in diameter (PM10); and oxides of sulfur (SOx), calculated as sulfur dioxides (SO_2), from Turbine A and the emergency fire pump described in Application No. 985748, except emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1(d)(1), shall not exceed the following limits for each rolling 12-calendar-month period:

Pollutant	*Emission Limit, tons per year*
a. NOx	*36.05*
b. CO	*169.95*
c. VOC	*11.85*
d. PM10	*19.5*
e. SOx	*2.8*

The aggregate emissions of each pollutant shall include emissions during all times that the equipment is operating including, but not limited to, emissions during commissioning, low load operation, startup, shutdown, and tuning periods. This condition will not apply on and after the date Turbine B completes its shakedown period. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

Verification: The project owner shall submit to the CPM and the District the facility 12-month rolling operating and emissions data demonstrating compliance with this condition as part of the monthly commissioning status report (**AQ-80**).

AQ-83 Beginning with the date Turbine A completes its shakedown period, aggregate emissions of carbon monoxide (CO); particulate matter less than or equal to 2.5 microns in diameter (PM2.5); and particulate matter less than or equal to 10 microns in diameter (PM10) from the three utility boilers described on District Permits to Operate No. 791, 792, and 793, shall not exceed the following limits for each rolling 12-calendar-month period:

Pollutant	*Emission Limit, tons per year*
a. CO	*198.75*
b. PM2.5	*21.80*
c. PM10	*26.89*

The aggregate emissions of each pollutant shall include emissions during all times that the equipment is operating including, but not limited to, emissions during commissioning, low load operation, startup, shutdown, and tuning periods. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

Verification: The project owner shall submit to the CPM and the District the facility 12-month rolling operating and emissions data demonstrating compliance with this condition as part of the monthly commissioning status report (**AQ-80**).

AQ-84 On and after the date that Turbine B completes its shakedown period, the three utility boilers described on District Permits to Operate No. 791, 792, and 793 shall not operate. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

Verification: The project owner shall submit to the CPM and the District information that the boiler regulated by this condition are no longer operational, or the steps being taken to ensure that they will not be operated, once Turbine B completes its shakedown period as part of the final monthly commissioning status report (**AQ-80**).

AQ-85 For each calendar month and each rolling 12-calendar-month period, the project owner shall maintain records on a calendar monthly basis, of aggregate mass emissions of NOx (calculated as NO_2), CO, and PM10 in tons, for Turbine A and the emergency generator described on Application No. 985748, except for emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1(d)(1). There records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

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

AQ-86 For each calendar month, the project owner shall maintain records on a calendar monthly basis, of mass emissions during each calendar month of NOx (calculated as NO_2), CO, PM10, and PM2.5, in tons, from each emission unit described on District Permits to Operate No. 791, 792, and 793. These records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

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

AQ-87 For each calendar month and each rolling 12-calendar-month period, the project owner shall maintain records on a calendar monthly basis, of aggregate mass emissions of NOx (calculated as NO_2), CO, PM10, and PM2.5, in tons, for the emission units described in District Permits to Operate No. 791, 792, and 793. There records shall be made available for inspection within 15 calendar days after the end of each calendar month. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

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

AQ-88 No later than 18 months before the initial startup of either combustion turbine, the project owner shall submit an application to the District for a significant Title V permit modification to limit the aggregate emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide; carbon monoxide (CO); particulate matter less than or equal to 10 microns in diameter (PM10); and particulate matter less than or equal to 2.5 microns in diameter (PM2.5), from

the three utility boilers described on District Permits to Operate No. 791, 792, and 793 in each rolling 12-calendar-month period as specified in this permit. The application shall include a proposed emissions calculation protocol to calculate the emissions from each emission unit. Where applicable, this protocol may rely in whole or in part on the CEMS or other monitoring protocols required by this permit. [Rules 20.3(d)(3), 20.3(d)(8), 1410 and 21]

Verification: The project owner shall submit copies of all applications and protocols required by this condition to the CPM for review within 5 days of their submittal to the District and no later than 18 months before the initial startup of either combustion turbine.

AQ-89 For each combustion turbine, the project owner shall submit the following notification to the District and U.S. EPA, Region IX:

a. A notification in accordance with 40 CFR Section 60.7(a)(1) delivered or postmarked not late than 30 calendar days after construction has commenced;

b. A notification in accordance with 40 CFR Section 60.7 (a)(3) delivered or postmarked within 15 calendar days after initial startup; and

c. An Initial Notification in accordance with 40 CFR Section 63.6145(c) and 40 CFR Section 63.9(b)(2) submitted no later than 120 calendar days after the initial startup of the turbine.

In addition, the applicant shall notify the District when: (1) construction is complete by submitting a Construction Completion Notice before operating any unit that is the subject of this permit, (2) each combustion turbine first combusts fuel by submitting a First Fuel Fire Notice within five calendar days of the initial operation of the unit, and (3) each combustion turbine first generates electrical power that is sold by providing written notice within 5 days of this event.

Verification: [Rules 24 and 21 and 40 CFR Part 75, 40 CFR Part 60 Subpart KKKK, 40 CFR Part §60.7, 40 CFR Part 63 Subpart YYYY, and 40 CFR Part §63.9]The project owner shall provide notification to the District and U.S. EPA Region IX as required by this condition and shall provide copies of these notifications as part of the final monthly commissioning status reports (**AQ-80**) due the month after the notifications are sent.

District Application Number 985093
An emergency fire pump engine, Cummins diesel engine, Model CFP6E-F35, as preliminarily proposed, rated at 246 brake horsepower.

CONDITIONS FOR EMERGENCY FIRE PUMP ENGINE

AQ-90 The engine shall be EPA certified to the 2009 model year or later requirements for emergency fire pump engines of 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal

Combustion Engines. [Rule 20.3(d)(1), 40 CFR Part 60 Subpart III, and 40 CFR Part 63 Subpart ZZZZ]

Verification: The project owner shall provide to the CPM for review and approval engine documentation demonstrating compliance with the condition at least 30 days prior to purchasing the engine.

AQ-91 Engine operation for maintenance and testing purposes shall not exceed 50 hours per calendar year. (ATCM reportable) [Rule 20.3(d)(1) and 17 CCR §93115]

Verification: The project owner shall submit to the CPM the fire pump engine operating data demonstrating compliance with this condition as part of the Quarterly Operation Report **(AQ-SC8)**.

AQ-92 The engine shall only use CARB Diesel Fuel. [Rule 20.3(d)(1), 69.4.1, and 17 CCR §93115]

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

AQ-93 Visible emissions including crankcase smoke shall comply with Air Pollution Control District Rule 50. [Rule 50]

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

AQ-94 The equipment described above shall not cause or contribute to public nuisance. [Rule 51]

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

AQ-95 This engine shall not operate for non-emergency use during the following periods, as applicable:

A. Whenever there is any school sponsored activity, if engine is located on school grounds or

B. Between 7:30 and 3:30 PM on days when school is in session, if the engine is located within 500 feet of, but not on school grounds.

This condition shall not apply to an engine located at or near any school grounds that also serve as the student's place of residence. (ATCM reportable) [17 CCR §93115]

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

AQ-96 A non-resettable engine hour meter shall be installed on this engine, maintained in good working order, and used for recording engine operating hours. If a meter is replaced, the Air Pollution Control District's Compliance

Division shall be notified in writing within 10 calendar days. The written notification shall include the following information:

A. Old meter's hour reading.

B. Replacement meter's manufacturer name, model, and serial number if available and current hour reading on replacement meter.

C. Copy of receipt of new meter or of installation work order.

A copy of the meter replacement notification shall be maintained on site and made available to the Air Pollution Control District upon request. [Rules 69.4.1, 17 CCR §93115, and 40 CFR Part 60 Subpart IIII]

Verification: The project owner shall provide notification to the District as required by this condition and shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-97 The owner or operator shall conduct periodic maintenance of this engine and add-on control equipment, if any, as recommended by the engine and control equipment manufacturers or as specified by the engine servicing company's maintenance procedure. The periodic maintenance shall be conducted at least once each calendar year. [Rule 69.4.1]

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

AQ-98 The owner or operator of the engine shall maintain the following records on site for at least the same period of time as the engine to which the records apply is located at the site:

A. Documentation shall be maintained identifying the fuel as CARB diesel;

B. Manual of recommended maintenance provided by the manufacturer, or maintenance procedures specified by the engine servicing company; and

C. Records of annual engine maintenance, including the date the maintenance was performed.

These records shall be made available to the Air Pollution Control District upon request. [Rule 69.4.1]

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

AQ-99 The owner or operator of this equipment shall maintain a monthly operating log containing, at a minimum, the following:

A. Dates and times of engine operation, indicating whether the operation was for maintenance and testing purposes or emergency use; and, the nature of the emergency, if known;

B. Hours of operation for all uses other than those specified above and identification of the nature of that use.

[Rule 69.4.1, and 17 CCR §93115]

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

ADDITIONAL TITLE V CONDITIONS

AQ-100 The project owner shall submit to the District and to the federal EPA a compliance certification for the new equipment subject to this permit, in a manner or form approved in writing by the District, within one year of completing construction of that equipment, that includes the identification of each applicable term or condition of the final permit for which the compliance status is being certified, the current compliance status and whether the modified equipment was in continuous or intermittent compliance during the certification period, identification of the applicable permitted method used to determine compliance during the certification period, and any other information required by the District to determine the compliance status. [Rule 1421]

Verification: The project owner shall submit to the District and U.S. EPA required Title V submittals and will provide the cover letters of these submittals to the CPM within 15 days of their submittal.

ACRONYMS

AAQS	Ambient Air Quality Standard
AERMOD	ARMS/EPA Regulatory Model
AFC	Application for Certification
APCD	Air Pollution Control District (SDAPCD)
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMP	Air Quality Management Plan
AQIA	Air Quality Impact Assessment
ARB	California Air Resources Board
ARM	Ambient Ratio Method
ATC	Authority to Construct
ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Technology
bhp	brake horsepower
BOP	Balance of Plant
Btu	British thermal unit
CAAQS	California Ambient Air Quality Standard
CCR	California Code of Regulations
CEC	California Energy Commission (or Energy Commission)
CECP	Carlsbad Energy Center Project
CEQA	California Environmental Quality Act
CEM	Continuous Emission Monitor
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTG	Combustion Turbine Generator
CPM	(CEC) Compliance Project Manager
DAHS	Data Acquisition and Handling System
dscf	dry standard cubic foot
dscm	dry standard cubic meter
EIR	Environmental Impact Report
ERC	Emission Reduction Credit
FDOC	Final Determination Of Compliance
FSA	Final Staff Assessment
GHG	Greenhouse Gas
gpd	gallons per day
gr	Grains (1 gr $\cong$ 0.0648 grams, 7000 gr = 1 pound)
HAP	Hazardous Air Pollutant
hp	horsepower
H_2S	Hydrogen Sulfide
ISCST3	Industrial Source Complex Short Term, version 3
LAER	Lowest Achievable Emission Rate
lbs	pounds
LORS	Laws, Ordinances, Regulations and Standards

MCR	Monthly Compliance Report
mgd	million gallons per day
mg/m^3	milligrams per cubic meter
MMBtu	Million British thermal units
m/s	meters per second
MW	Megawatts (1,000,000 Watts)
NAAQS	National Ambient Air Quality Standard
NH_3	Ammonia
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates
NOx	Oxides of Nitrogen *or* Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
O_3	Ozone
OLM	Ozone Limiting Method
PDOC	Preliminary Determination Of Compliance
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PSA	Preliminary Staff Assessment (this document)
PSD	Prevention of Significant Deterioration
PTO	Permit to Operate
PVMRM	Plume Volume Molar Ratio Method (NO_2 dispersion modeling method)
RATA	Relative Accuracy Test Audit
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SDAB	San Diego Air Basin
SDAPCD	San Diego Air Pollution Control District
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfate
SOx	Oxides of Sulfur
T-BACT	Best Available Control Technology for Toxics
ULN	Ultra Low NOx
U.S. EPA	United States Environmental Protection Agency
$\mu g/m^3$	Microgram per cubic meter
VOC	Volatile Organic Compounds

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APPENDIX AIR-1

Greenhouse Gas Emissions

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

INTRODUCTION AND SUMMARY OF CONCLUSIONS

The Carlsbad Energy Center Project (CECP) burns natural gas for fuel and thus has greenhouse gas (GHG) emissions that contribute cumulatively to climate change. However, CECP is an intermediate (or mid-merit)[1] project that will operate on an as needed basis to provide local grid reliability support. This will allow the closure of existing older units (Encina units 1, 2, and 3) that are less efficient, and displace in the dispatch order other peaking power plants that burn natural gas less efficiently. Thus, CECP decreases the overall amount of GHG emissions[2] per megawatt-hour for both California and the Western Interconnect[3].

While CECP would emit GHG emissions, the relative efficiency of CECP and the system build-out of renewable resources in California would result in a net cumulative reduction of energy and GHG emission from new and existing fossil resources. Electricity is produced by operation of inter-connected generation resources. Operation of one power plant, like CECP, affects all other power plants in the interconnected system. The operation of the CECP facility will have an impact upon system operation and GHG emissions in several ways:

- CECP would replace aging and inefficient boiler units, and displace less efficient peaking or mid-merit capacity in the dispatch order of gas-fired facilities that are required to provide electricity reliability in the local reliability area (LRA).
- CECP would provide flexible peaking or mid-merit power necessary to integrate the growing generation from intermittent renewable sources, such as wind and solar generation.
- CECP would in some measure replace out of state high GHG-emitting electricity generation that must be phased out to meet the State's new Emissions Performance Standard.

[1] A mid-merit generating plant is generally defined as a plant that operates to meet system loads between minimum daily load, where base load plants generally provide load up to that point, and the start of peak load, where peaking plants operate to meet peak demand. Mid-merit plants include, but are not limited to, one or more of the following characteristics: quick-starting, rapid response to changing loads, high turndown ranges, good efficiency, and no cogeneration obligations that might limit dispatch. Most California natural gas-fired plants, except dedicated peaking and cogeneration plants, are mid-merit plants.

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

[3] The Western Interconnect is the interconnected power plant and transmission system of which California is a part. This system, which is coordinated by the Western Electricity Coordinating Council (WECC), electrically connects the western states of the U.S., plus parts of western Canada and Mexico.

- CECP would replace peaking or mid-merit generation provided by aging power plants that use once-through cooling that currently provide necessary local reliability.

These system impacts would result in a net reduction in GHG emissions across the electricity system providing energy and capacity to California. Thus, Staff believes that the project would result in a cumulative overall reduction in GHG emissions from power plants, does not worsen current conditions, and would not result in impacts that are cumulatively 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.

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 would be permitted to have more than 800,000 metric tons of carbon dioxide equivalent emissions and would be subject to additional reporting requirements (and possibly GHG reductions or trading requirements as these regulations are more fully developed and implemented).

The project would be consistent with the requirements of SB 1368 (Perata, Chapter 598, Statutes of 2006) and the Greenhouse Gas Emission Performance Standard even though the project, as a peaking or mid-merit project with an enforceable operating limitation less than 60 percent of capacity, is not subject to the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard.

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.)	This act requires the California Air Resources Board (ARB) to enact standards that will reduce GHG emission to 1990 levels by the year 2020. Electricity production facilities will be regulated.
California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)

Applicable Law	Description
State	
Title 20, California Code of Regulations, section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009	This regulation prohibits 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 mt CO_2/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO_2/MWh)

GLOBAL CLIMATE CHANGE AND ELECTRICITY PRODUCTION

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

In 1998 the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p.5). In 2003, the Energy Commission recommended that the state require reporting of greenhouse gases (GHG) or global climate change[4] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the California Air Resources Board (ARB) to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020.[5] 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.

[4] 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.

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

Examples of strategies that the state might pursue for managing GHG emissions in California, in addition to those recommended by the Energy Commission and the Public Utilities Commission, were identified in the California Climate Action Team's Report to the Governor (CalEPA 2006). The scoping plan approved by ARB in December 2008 builds upon the overall climate policies of the Climate Action Team report and show the recommended strategies to achieve the goals for 2020 and beyond. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy), land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). The scoping plan includes a 33 percent Renewables Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade system that includes the electricity sector (ARB 2008b).

It is possible that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will be based on cost-effectiveness (i.e., the greatest effect for the least cost). For example, the ARB proposes a 40 percent reduction in GHG from the electricity sector, even though that sector currently only produces about 25 percent of the statewide GHG emissions. In response, in September 2008 the Energy Commission and the Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified 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 2007). For the electricity sector, it recommends such approaches as pursuing all cost-effective energy efficiency measures and meeting the Governor's stated goal of a 33 percent renewable portfolio standard.

SB 1368,[6] also enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Greenhouse Gas Emission Performance Standard of 0.500 metric tonnes CO_2 per megawatt-hour[7] (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.[8] 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 percent. As a project with a permit operating restriction of less than 60 percent of the year, CECP is not required to comply with the SB 1368 EPS.

[6] Public Utilities Code § 8340 et seq.

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

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

In addition to these programs, California is involved in the Western Climate Initiative, a multi-state and international effort to establish a cap and trade market to reduce greenhouse gas emissions in the Western United States and the Western Electricity Coordinating Council (WECC). The timelines for the implementation of this program are similar to those of AB 32, with full roll-out beginning in 2012. And as with AB 32, the electricity sector has been a major focus of attention.

ELECTRICITY PROJECT GREENHOUSE GAS EMISSIONS

Electricity use can be as simple as turning on a switch to operate a light or fan. The system to deliver the adequate and reliable electricity supply is complex and variable. But it operates as an integrated whole to meet demand, such that the dispatch of a new source of generation generally curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). Ancillary services[9] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system mix. 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.

[9] See CEC 2009b, page 95.

The generation of electricity using fossil fuels, including natural gas, can produce air emissions known as greenhouse gases in addition to the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. Greenhouse gas emissions contribute to the warming of the earth's atmosphere, leading to climate change. For fossil fuel-fired power plants, 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. The construction duration for the CECP is scheduled to last 25 months if built in one phase, but would be longer if the construction is separated into two phases for Units 6 and 7. **Greenhouse Gas Table 2** shows what the proposed project, as permitted, could potentially emit in greenhouse gases during construction. All emissions are converted to CO_2-equivalent (MTCO2E) and totaled for the proposed 25 month construction schedule.

Greenhouse Gas Table 2
CECP Estimated Potential Construction Greenhouse Gas Emissions

Construction Element	CO_2 Equivalent (MTCO2E) [a]
Tank Demolition and Remediation	135
Site Grading and Preparation	260
Main Site Construction	3,410
Berm Work	512
Ocean Water Purification System	154
Switchyard Construction	215
Construction Total	4,686

Source: Staff estimate based on construction data provided by the applicant (CECP 2007a and SR 2007d, 2008a, 2008f, 2008h) where staff used the latest ARB GHG emission factor recommendations (ARB 2008a).
Note:
[a] One metric tonne (mt) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms

PROJECT OPERATIONS

The proposed Carlsbad Energy Center Project would be a rapid-response combined cycle facility that would be limited to an equivalent of 4,100 hours of full load operation.

The two Siemens SGT6 gas turbines are fired with natural gas and the gas turbines are the primary sources of GHG emissions. There will also be a small amount of GHG emissions from the diesel fuel consumed in the new emergency fire pump engine, and sulfur hexafluoride emissions from electrical component equipment. The employee and delivery traffic GHG emissions are not included in the operating emission GHG totals and are negligible in comparison with the gas turbine GHG emissions.

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 dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG 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 large relative global warming potentials.

Greenhouse Gas Table 3
CECP Estimated Potential Operating Greenhouse Gas Emissions

	Project Emissions (metric tonnes [a] per year)	Global Warming Potential [b]	CO_2-equivalent (MTCO2E per year)
Carbon Dioxide (CO_2)	844,091	1	844,091
Methane (CH_4)	14.4	21	302
Nitrous Oxide (N_2O)	1.6	310	495
Hexafluoride (SF_6)	0.05	23,900	1,188
Hydrofluorocarbons (HFCs)	0	--- [c]	0
Perfluorocarbons (PFCs)	0	7,850 [d]	0
Total Project GHG emissions – MTCO2E per year			846,076
Total Project MWh per year (net) [e]			2,089,764
Project CO_2 Emissions Performance - MTCO2/MWh			0.404
Project GHG Emissions Performance - MTCO2E per MWh			0.405

Sources: CECP 2007a and SR 2007b, where staff updated the natural gas GHG emissions factors to use the latest ARB recommendations (ARB 2008a).
Notes:
[a] One metric tonne (mt) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] The global warming potential is a measure of the chemicals' warming properties and lifetime in the atmosphere relative to CO_2. The value shown is based on the emission factors from the latest ARB GHG emission factor recommendations (ARB 2008a).
[c] Can vary from 150 to 10,000, depending on the specific HFC.
[d] This figure is an average Global Warming Potential for the two PFCs, CF_4 and C_2F_6.
[e] This reflects net base load power without power augmentation, and includes staff's parasitic power consumption estimated for the on-site desalination unit (1,236 MWh/year).

The proposed project would be permitted, on an annual basis, to emit over 800,000 metric tonnes of CO_2-equivalent per year if operated at its maximum permitted level. Since the project's permit limits operation to less than a 60 percent annual capacity factor, the project is not subject to requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard. However, the Carlsbad Energy Center Project, at 0.405 MTCO2E/MWh, would meet the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard of 0.500 MTCO2/MWh.

Because the proposed project is an addition to an existing power plant station, staff evaluated past GHG-emissions performance of the existing units. The recent year CO_2-equivalent emissions for existing boilers 1 through 3 are provided in **Greenhouse Gas Table 4**. The emissions are combined for Units 1 thought 3 since they will all be replaced by the proposed CECP Units 6 and 7.

Greenhouse Gas Table 4
Existing Carlsbad Units 1-3 Operations and CO_2 Emissions

Year	Net MWh	CO2 Emissions (MTCO2)	CO2 Rate (MTCO2/MWh)
2002	497,122	315,791	0.635
2003	459,332	295,421	0.643
2004	715,503	443,422	0.620
2005	483,535	308,148	0.637
2006	241,505	161,081	0.667
2007	175,137	111,632	0.637
2008	104,368	69,162	0.663
Averages	382,357	243,523	0.637

Source: Staff based on QFER data, where GHG emission factors are based on latest ARB recommendations (ARB 2008a).

As this table shows the existing boiler GHG emission rate is calculated to be on average almost 60 percent higher than the estimated CECP GHG emission rate. This difference might be slightly lower under real project operating conditions, which would include a reduced actual CECP capacity factor and slightly lower efficiencies for the new facility due to additional startups and shutdowns.

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 construction and electricity sectors.

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 fossil-fueled generation resources to provide energy and satisfy local capacity needs. As directed by the OII (CEC 2009a), staff is refining and implementing the concept of a blueprint that describes the long-term 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). CECP 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 small GHG emission increases from construction activities would be significant for several reasons. First, the period of construction will be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures that staff recommends to address criteria pollutant emissions, such as limiting idling times and requiring, as appropriate, equipment that meets the latest criteria pollutant emissions standards would further minimize greenhouse gas emissions to the extent feasible. The use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

New, efficient, natural gas-fired generation promotes the state's efforts to improve GHG electrical generation efficiencies, therefore, reduce greenhouse gas emissions and the amount of natural gas used by electricity generation. As the *2007 Integrated Energy Policy Report* (CEC 2007, p. 184) noted:

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

Thus, in the context of the Energy Commission's *Integrated Energy Policy Report*, the CECP's replacement of the existing three power boilers furthers the state's strategy to promote generation system efficiency and reduce 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.23):

> 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 percent 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). CECP, with its lower heat rate than most other dispatchable gas-fired generation in the state, would be cheaper, operated preferentially, and lower GHG emitting.

The Integrated Electric System And Displacement Of Emissions

The Western Interconnect

As previously indicated, the term Western Interconnect is often used to describe the interconnected transmission and generation system in the Western United States, western Canada, and small parts of northern Mexico. It is this system that allows California to import power from distant places both inside and outside of California. This includes out-of-state hydro power (much of it from the northwest), coal power (much of it from the mountain states and southwest), nuclear power (from Arizona), and increasingly renewable power generation (from the Southwest). Although imported power averages about 30 percent of the electricity used within the state, the majority of the megawatt-hours consumed in California are also generated in California (CEC 2009b, p. 23). The mix of imported electricity varies seasonally (hydro imports from the northwest occur mainly in the summer) and year to year, based on hydro conditions, snow pack, and other factors.

Old and New Power Plants

Roughly 45 percent of California's in-state generation is gas-fired (CEC 2009b, p. 23). This gas-fired generation comes from power plants that range widely in size, technology, and age. The oldest gas-fired plants were built in the 1950s, and many of these older plants use boilers and once-through cooling. Most of the older facilities were built as base-load facilities that were intended to operate more than 80 percent of the hours of the year. However, as other resources were added to the system, many boiler units were modified to allow them to operate as the mid-merit units (dispatchable, load following, with high turndown ranges). Some units operate infrequently throughout the year while other units sit in standby status to be ready for the few hundred hours of the year when demand is highest (usually afternoons in summer or early fall) or for an emergency such as the forced outage of one of the nuclear facilities. Because they use large boilers with inherently lengthy startup times, many boiler facilities operate at minimum load (e.g., 5 percent of rated capacity) overnight to be able to follow the load curve up the next day. As a consequence, these older facilities have some emissions even at night. Newer gas-fired facilities employing gas turbines rather than boilers, can be turned off when not in use, and are generally much more efficient than older gas-fired units.

Although, as described previously, California's electric system is being rapidly changed by renewable generation, gas-fired plants are necessary to provide reliability. This is because electricity demand is instantaneous and because electricity cannot be stored in large quantities. Load serving entities must have capacity that they can quickly dispatch to meet fluctuating demand, including for emergencies and for peak load summer days. Some of this gas generation must be in the form of peakers that provide power when demand is highest, but it is also necessary to have load following generation that can run in place of intermittent renewable generation when such renewables are not generating (i.e., when the wind doesn't blow, when it is cloudy, or after dark). Gas-fired facilities serve this purpose in California.

The Role of CECP in Local Generation Displacement

Local Capacity Requirements in the San Diego Basin

Capacity is the total amount of electric generation (expressed in MW) needed to meet instantaneous demand. A reliable electric system must have enough capacity to meet load demand on a hot summer afternoon when air conditioning demand is high in a given area. Many urban areas have intense electricity loads that surpass what can be delivered purely from transmission from more distant places. These load pockets can only have reliable electric service if, based on utility reliability criteria (adopted by the federal government), additional capacity can be generated by power plants within the load pockets. These load pocket requirements are also called local capacity requirements.

The California Independent System Operator (CAISO) is responsible for electricity grid system reliability, among other issues. CAISO has performed a study that estimates the amount of capacity needed in the San Diego area to meet local reliability needs (CAISO 2008). This study estimates that San Diego needs 2,418 MW of capacity to meet local reliability requirements in 2013 assuming that the Sunrise Powerlink is completed.[10]

Currently the San Diego area has 2,942 MW of generation capacity. This includes a total of 1,668 MW at two facilities: Encina (960 MW) and South Bay (708 MW). Encina generation is from boiler facilities that started operation in the 1950s (Units 1-3) and 1970s (Units 4 and 5) and are currently operating as mid-merit units under contract with CAISO. South Bay generation is from boilers that started operation in the 1960s (Unit 4 started operation in 1971). Local load pockets have transmission constraints as to how much power can be imported from outside the pocket, so some units are required to operate within the pocket to meet load or maintain grid stability—even if these reliability units are old, inefficient, and expensive generating units. The units—South Bay and Encina—have RMR (reliability must run) contracts with the CAISO for this purpose. The 2005 IEPR and 2007 IEPR identified these as among the aging facilities that the state needs to shut down, repower, or replace, while preserving system reliability in the San Diego load pocket. This policy is endorsed by the CAISO, the California Public Utilities Commission, and the State Water Resources Control Board; the latter agency insists that all once-through cooling facilities (like those at South Bay and Encina) eventually be replaced by power plants that do not use this form of cooling technology.

Shutting down Encina and South Bay would remove 1,668 MW of generation from the San Diego load pocket. On the other hand, several generation projects other than CECP are currently being constructed or are in the licensing process and these will increase load pocket generation. These are depicted in the following table:

[10] Until the Sunrise Powerlink is completed, San Diego needs roughly and additional 1000 MW of capacity.

Greenhouse Gas Table 5: Pending Projects in San Diego Basin

Project Name	Technology	MW	Status
Otay Mesa	NG combined cycle	561	Under Construction
Orange Grove	NG peakers	94	Under Construction
Wellhead Margarita	NG peaker	44	On Hold
Bull Moose	Biomass	27	Undergoing Permit Review
Lake Hodges	Pump Storage Hydro	40	Under Construction

Source: CAISO 2008. Status determined by Energy Commission staff.

Assuming the addition of all the new facilities shown in the above table, 766 MW will be added to the San Diego load pocket prior to 2013. Retirement of Encina and South Bay would nevertheless constitute a net reduction of capacity in San Diego of 902 MW, leaving 2,022 MW of local capacity. This is 396 MW less than that estimated by the CAISO as necessary to meet local capacity requirements. The capacity provided by CECP will allow for the retirement of the Encina units (1-3) and (with the Sunrise Powerlink) South Bay; it should also reduce operation of Encina Units 4-5, and facilitate their future retirement.

Efficiency and GHG Emissions

CECP would be more efficient than the Encina and South Bay units. CECP would have a net heat rate as low as 7,147 Btu/kWh[11] and an estimated annual GHG performance factor of 0.405 MTCO2/MWh. The heat rate, energy output and GHG emissions of local fossil fueled generation resources[12] in the greater San Diego area and the heat rates of these other local units are listed in **Greenhouse Gas Table 6**. Compared to other units in the San Diego control area, CECP would be more efficient, and emit fewer GHG emissions during any hour of operation than every peaking unit or boiler unit. It is expected that CECP would dispatch before most of these peaking units or boiler units in most situations. The dispatch, or loading order of generation resources, is clearly shown in **Greenhouse Gas Table 6**. Those units with the best, or lowest heat rate or lowest MTCO2/MWh rate, generally operate more than other units with higher heat rates, as shown by the relative amount of energy (GWh) produced in 2008 from these generating units in the Greater San Diego Area. 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, local reliability needs or emergencies. These deviations, however, are likely to occur infrequently.

[11] Based on the High Heating Value (HHV) of the fuel(s) used. The theoretical heat rate does not include start-up and low load operations fuel use that will result in a higher actual heat rate. HHV is used for all heat rate and fuel conversions to GHG mass emissions that are discussed in this document.

[12] All fossil fueled sources over 10 net MW of generation.

Greenhouse Gas Table 6
Greater San Diego Area, Local Generation Heat Rates and 2008 Energy Outputs

Plant Name	Capacity (MW)	Capacity Factor	2008 Heat Rate (Btu/kWh)[a]	2008 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Palomar Energy Center	559	73.1%	6,959	3,590.37	0.368
South Bay Power Plant (1-4) [b]	696	16.7%	11,534	1,015.24	0.610
Encina Power Plant (1-5) [b]	951	12.0%	12,360	997.01	0.654
Larkspur Energy LLC (1-2) [c]	90	8.0%	10,019	63.22	0.530
CalPeak Power - Border [c]	50	3.4%	10,772	14.73	0.570
CalPeak Power - Enterprise [c]	49	3.0%	10,743	12.92	0.568
CalPeak Power - El Cajon [c]	49	2.8%	10,961	12.04	0.580
Kearny (1-3D) [c]	127	0.4%	16,723	4.46	0.885
MMC Chula Vista, LLC [c]	44	0.5%	16,596	1.92	0.878
MMC Escondido, LLC [c]	44	0.4%	18,391	1.73	0.973
Miramar (1A-1B) [c]	33	0.3%	18,018	0.89	0.953
El Cajon [c]	13	0.6%	19,851	0.67	1.050
South Bay Peaking Turbine [c]	13	0.5%	16,234	0.54	0.859
Encina Peaking Turbine [c]	14	0.3%	17,634	0.37	0.933

Source: Energy Commission Staff
Note:
a. Based on the Higher Heating Value or HHV of the fuel. The heat rate includes start-up and low load operations fuel use.
b. Boiler facilities.
c. Peaker facilities.

The Role of CECP in Local Boiler Generation Displacement

Carlsbad Energy Center project would operate to replace energy and capacity from the existing three boiler units (Encino Units 1-3) that will be retired, as well as displace other less efficient local peaking power and old coastal boiler generation sources in San Diego County, including that Encina Units 4 and 5 that would remain after CECP begins operation, and the South Bay Power Plant.

Greenhouse Table 7 provides the historic use, heat rate, and GHG performance for the nine total Encina and South Bay boiler units.

Greenhouse Gas Table 7
Encina and South Bay Boiler 2002-2008 Generation,
Average Heat Rates and GHG Performance

Plant Name	Capacity (MW)	Energy Output (GWh)							2002-2008 Average Heat Rate (Btu/kWh)[a]	2002-2008 Average GHG Performance (MTCO2/MWh)
		2002	2003	2004	2005	2006	2007	2008		
Encina 1	107	140	115	170	146	43	56	7	12,146	0.642
Encina 2	104	177	141	216	157	87	40	32	12,268	0.649
Encina 3	110	181	203	330	180	112	79	65	11,788	0.623
Encina 4	300	870	886	1,153	806	470	202	289	11,817	0.625
Encina 5	330	985	1,095	1,237	576	542	327	604	11,146	0.589
South Bay 1	136	423	406	519	546	387	167	211	10,670	0.564
South Bay 2	136	442	440	649	410	322	190	206	10,598	0.560
South Bay 3	210	299	409	548	435	129	241	400	10,961	0.580
South Bay 4	214	77	46	235	126	89	150	216	12,877	0.681
Total/Average	1,647	3,593	3,743	5,057	3,383	2,181	1,451	2,031	11,330	0.599

Source: Energy Commission Staff
Note:
a. Based on the Higher Heating Value or HHV of the fuel. The heat rate includes start-up and low load operations fuel use.

The total generation for the Encina[13] and South Bay boilers has steadily been decreasing over time, and showed a marked reduction when the Palomar Energy Center started operation in 2006. This trend should continue into the future with the potential for marked reductions with the Otay Mesa Power Plant starting operation in October 2009, and if and when the CECP is built and starts operation. With the addition of the Sunrise Power Link the need for in-basin capacity is reduced and with the addition of Palomar and Otay Mesa projects the South Bay facility can be retired. However, these three projects do not provide adequate capacity to retire Encina and the addition of the CECP should hasten the permanent shutdown of both South Bay and Encina facilities. The 2002 to 2008 average GHG emissions per megawatt of power

[13] The capacity factor for the entire Encina facility averaged 21.8 percent from 2002 through 2008, with the maximum of 37.2 percent occurring in 2004 and the minimum of 8.5 percent occurring in 2007. The capacity factors for Units 1 through 3 averaged 13.6 percent from 2002 through 2008, with the maximum of 25.4 percent occurring in 2004 and the minimum of 3.7 percent occurring in 2008. The capacity factors for Units 4 and 5 averaged 30.0 percent from 2002 through 2008, with the maximum of 43.2 percent occurring in 2004 and the minimum of 9.6 percent occurring in 2007.

production, or in other words, the thermal efficiency and economic competiveness, of these boiler units is over 45 percent higher, or worse than the CECP project's best forecast performance; therefore, any generation displacement of these boiler units by CECP generation would reduce the GHG emissions generated from San Diego area generating facilities.

The above figures do not fully capture the foreseeable impact of CECP replacing the older units at Encina and South Bay as the provider of local reliability services. Local reliability requires that generating capacity be available for dispatch in amounts that are determined by the peak load forecast for the day. On days when steam turbines at Encina or South Bay have been needed to meet local capacity requirements, these older units have been run at minimum output for hours—often entire nights—before being called on for their capacity. By contrast, CECP can be called on to run at the time it is actually needed for reliability. **Greenhouse Gas Table 8** indicates the share of hours than Encina and South Bay units operated in 2007 between 10 pm and 6 am.

Greenhouse Gas Table 8
Hours of Operation Between 10:00 p.m. and 6:00 a.m.
Encina 1-5 and South Bay 1-4, 2007

Unit	Hours Operated	Hours Operated 10:00 pm – 6:00 am	Percent of Hours Operated
Encina 1	1,307	415	31.8%
Encina 2	880	272	30.9%
Encina 3	1,735	546	31.5%
Encina 4	2,740	891	32.5%
Encina 5	3,463	1,134	32.7%
South Bay 1	2,710	881	32.5%
South Bay 2	3,026	988	32.7%
South Bay 3	3,682	1,207	32.8%
South Bay 4	1,813	573	31.6%

The Role of CECP in Renewables Goals/Load Growth

As California moves towards an increased reliance on renewable energy, the bulk of renewable generation available to and used in California in the near to intermediate future will be intermittent wind generation with some intermittent solar generation (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[14] and fast starting[15] fossil fuel generation resources (CAISO 2007, p. 14).

[14] 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.

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

CECP, as a peaking or mid-merit facility, would provide flexible, dispatchable, and fast start power that would not obstruct penetration of renewable energy. In general, combustion turbines can startup quickly, but the output of a large-scale combined cycle facility can be limited by the steam turbine to about 15 MW per minute.[16] The CECP rapid response turbines, under hot start conditions, would be capable of ramping up to 150 MW of output within ten minutes and capable of a 45 minute complete startup cycle. Intermittent renewable sources of energy would be accommodated by CECP varying its energy output as needed to integrate the renewable sources, which enables CECP to play a role in most system operating scenarios.[17]

The amount of dispatchable fossil fuel generation used as regulation resources, fast ramping resources, or load following or supplemental energy dispatches will have to be significantly increased due to the planned intermittent resources needed to meet the 20 percent RPS (CAISO 2007, p.113); the 33 percent RPS goal established for 2020 by Governor Schwarzenegger in Executive Order S-14-08 will require even more dispatchable generation to integrate renewable generation. However, this does not suggest the existing and new fossil fuel capacity will operate more in terms of total generation, but will need to operate more in a supplementary rather than base load role. **Greenhouse Gas Table 9** shows how the build-out of either the 20 percent or the 33 percent Renewable Portfolio Standards will affect generation from new and existing non-renewable resources. Should California reach its goal of meeting 33 percent 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[18] will need to come from renewable resources to achieve the 33 percent 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.[19] 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, totaling as much as 45,000 GWh per year of reduced non-renewable energy depending on the RPS goal.

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[16] 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).

[17] It is important to note that renewable generation is just one source of intermittency, or variability, that fast ramping plants can and do accommodate for in the California electric system, such as inaccurate load and weather forecasts, and unscheduled generation outages.

[18] There is a difference between annual generation and peak short term generation needs. While there is a need to increase in the short term fast ramping and starting fossil fuel fired generation sources like CECP its operation will normally be needed when intermittent renewable generation is low and as required to displace older less efficient facilities.

[19] 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 9
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 between 2008 to 2020 [c]	32,440	72,489
Resulting Change in Non-Renewable Energy [d]	13,876	(-36,173)

Source: Energy Commission staff
Notes:
a. Not including eight percent transmission and distribution losses
b. Based eight percent 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 eight percent transmission and distribution losses.
d. Based on net energy (including eight percent transmission and distribution losses), not based on retail sales.

This gradual decline in the use of gas-fired *energy* in California has been projected by the Energy Commission and the CPUC, based on the state's loading order, efficiency programs, and RPS goals. The 2007 IEPR scenario analysis estimates a significant decline under any electric system demand-supply scenario other than business as usual; gas-fired energy generation is forecast to decline as a proportion of total generation by 2020 by as much as 50 percent (CEC 2007, Figure 2-14, p. 49). Likewise, the Energy Commission/CPUC Joint Decision projects that aggressive RPS and energy efficiency goals should reduce GHG emissions from electricity 27 percent as compared to 1990, and by 38 percent compared to business as usual projections for 2020 (CPUC 2008, p. 112). Notably, these decreases are projected in the absence of any implementation of cap and trade provisions which might be required by ARB as they implement AB 32 requirements.

Thus, gas-fired generation is needed in significant amounts to integrate large amounts of renewable generation that will soon be added to the electricity system. However, this gas-fired generation will not supplant renewable generation, nor will it add to the overall amount of carbon from the electricity system as a whole. Rather, it will reduce it, or enable renewable electricity generation to do so.

The Role of CECP in the Retirements/Replacements

CECP would be capable of annually providing over 2,000 GWh of natural gas-fired generation energy 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 generation, such as coal-fired generation; generation that relies on water for once-through cooling; and aging power

plants (CEC 2007). 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.

Replacement of High GHG-Emitting Generation

High GHG-emitting resources, such as coal, are effectively prohibited from entering into new contracts for California electricity deliveries as a result of the Emissions Performance Standard adopted in 2007 pursuant to SB 1368. Between now and 2020, more than 18,000 GWh of energy procured by California utilities under these contracts will have to reduce GHG emissions or be replaced; these contracts are presented in **Greenhouse Gas Table 10**.

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[20], all the coal contracts (including those in **Greenhouse Gas Table 10**, 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 economically 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 SB1368 Emission Performance Standard. As these contracts expire, new and existing generation resources will replace the lost energy and capacity. Some will come from renewable generation; some will come from new and existing natural gas fired generation. All will emit significantly less GHG than the coal and petroleum coke-fired generation, which average about 1.0 $MTCO_2$/MWh, or about two times as much as new peaker projects and two and a half times more than new gas-fired combined-cycle projects like CECP. This will result in a significant net reduction in GHG emissions from the California electricity sector.

Greenhouse Gas Table 10
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 Qualifying Facilities [a]	2009-2019	4,086
LADWP	Intermountain [b]	2009-2013	3,163
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 in this table are located out-of-state except for the Miscellaneous In-state Qualifying Facilities.

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

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 capacity like CECP 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 2007, these units collectively produced over 58,000 GWh. While those OTC facilities owned and operated by utilities and recently-built combined cycles may well install dry or wet cooling towers, it is unlikely that the aging, merchant OTC 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-complete aging plants and would displace the energy provided by OTC facilities and likely accelerate their retirement.

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. For the Greater San Diego Area there was a total of 1,567 MW of merchant capacity and 2,000 GWh of merchant energy in 2008. **Greenhouse Gas Table 11** provides a summary of the statewide utility and merchant energy supplies affected by the OTC regulations.

New generation resources that can either provide local support or energy will emit significantly less GHGs. Existing aging and OTC natural gas generation average 0.6 to 0.7 MTCO2/MWh, which are less efficient, higher GHG emitting than a new natural gas-fired combined-cycle project like CECP. When a project can provide energy and capacity, given its location, it can provide a significant net reduction in GHG emissions from the California electricity sector. A project like CECP that is located in a coastal load pocket, like the Greater San Diego Area, would more likely provide local reliability support as well as facilitate the retirement of aging and/or OTC power plants.

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.

Greenhouse Gas Table 11
Units Utilizing Once-Through Cooling: Capacity and 2008 Energy Output [a]

Plant, Unit Name	Owner	Local Resource Area	Aging?	Capacity (MW)	2008 Energy Output (GWh)	GHG Performance ($MTCO_2$ /MWh)
Diablo Canyon 1, 2	Utility	None	No	2,232	17,090,526	Nuclear
San Onofre 2, 3	Utility	L.A. Basin	No	2,246	15,391,825	Nuclear
Broadway 3 [b]e	Utility	L.A. Basin	Yes	75	89,899	0.648
El Centro 3, 4 [b]	Utility	None	Yes	132	237,581	0.814
Grayson 3 - 5 [b]	Utility	LADWP	Yes	108	149,746	0.799
Grayson CC [b]	Utility	LADWP	Yes	130	27,297	0.896
Harbor CC	Utility	LADWP	No	227	203,034	0.509
Haynes 1, 2, 5, 6	Utility	LADWP	Yes	1,046	1,529,287	0.578
Haynes CC	Utility	LADWP	No	560	3,423,312	0.376
Humboldt Bay 1, 2 [a]	Utility	Humboldt	Yes	107	507,094	0.683
Olive 1, 2 [b]	Utility	LADWP	Yes	110	11,400	1.008
Scattergood 1 – 3	Utility	LADWP	Yes	803	1,327,166	0.618
Utility-Owned				**7,776**	**39,988,167**	**0.693**
Alamitos 1 – 6	Merchant	L.A. Basin	Yes	1,970	2,532,746	0.661
Contra Costa 6, 7	Merchant	S.F. Bay Area	Yes	680	159,556	0.615
Coolwater 1 – 4 [b]	Merchant	None	Yes	727	576,224	0.633
El Segundo 3, 4	Merchant	L.A. Basin	Yes	670	507,761	0.576
Encina 1 – 5	Merchant	San Diego	Yes	951	997,011	0.674
Etiwanda 3, 4 [b]	Merchant	L.A. Basin	Yes	666	848,441	0.631
Huntington Beach 1, 2	Merchant	L.A. Basin	Yes	430	915,677	0.591
Huntington Beach 3, 4	Merchant	L.A. Basin	No	450	620,141	0.563
Mandalay 1, 2	Merchant	Ventura	Yes	436	596,705	0.528
Morro Bay 3, 4	Merchant	None	Yes	600	83,386	0.524
Moss Landing 6, 7	Merchant	None	Yes	1,404	1,375,335	0.661
Moss Landing 1, 2	Merchant	None	No	1,080	5,790,706	0.378
Ormond Beach 1, 2	Merchant	Ventura	Yes	1,612	783,061	0.573
Pittsburg 5 – 7	Merchant	S.F. Bay Area	Yes	1,332	179,572	0.673
Potrero 3	Merchant	S.F. Bay Area	Yes	207	530,220	0.587
Redondo Beach 5 - 8	Merchant	L.A. Basin	Yes	1,343	316,660	0.810
South Bay 1 - 4	Merchant	San Diego	Yes	696	1,015,242	0.611
Merchant-Owned				**15,254**	**17,828,444**	**0.605**
Total In-State OTC				**23,030**	**57,816,611**	

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, startup and enter commercial operation.
b. Units are aging but are not OTC.

COMPLIANCE WITH LORS

Ultimately, ARB's AB 32 regulations may 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 programmatic approach 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 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 entire 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.

This project would be subject to ARB's mandatory reporting requirements and potentially other future requirements mandating compliance with AB 32 that are being determined 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 be consistent with the policies described above and the regulations that ARB adopts and provide the information to demonstrate compliance with any applicable new or revised EPS that could be enacted in the next few years. Since this power project would be permitted for less than a 60 percent annual capacity factor[21] and could be considered a peaking/mid-merit generating facility, the project is not subject to the requirements of SB 1368 and the current Emission Performance Standard. Regardless, CECP's GHG emission performance would be well below the SB 1368 EPS.

[21] While SB 1368 regulates separate generating units, where CECP Units 6 and 7 are separate units and Encina Units 4 and 5 are separate units under this regulation, even if the regulation were to regulate all of these separate units as a combined entity there is no reasonable potential that the entire facility could exceed a 60 percent capacity factor as Encina Units 4 and 5 would have to exceed a capacity factor of 70 percent for that to occur. Encina Units 4 and 5 have only averaged a combined 30 percent capacity factor from 2002 to 2008, and have had a combined maximum capacity factor of 43.2 percent during that period. Additionally, as long as slightly more than half of the site total generation comes from CECP Units 6 and 7, which would be expected due to its significantly higher efficiency, then the site total GHG emission performance would be below the SB 1368 EPS limit of 0.500 MTCO2/MWh.

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 estimated. Operation of one power plant, like CECP, affects all other power plants in the interconnected system. The operation of the CECP facility will have an impact upon system operation and general reduction in system-wide GHG emissions in several ways:

CECP would displace three existing power boilers (Units 1 through 3) with a total 321 MW of generation capacity that would be permanently shut down following the commissioning of the new units. The proposed project would improve the overall thermal efficiency of the generation mix due to the higher efficiency of the two new natural gas-fired Siemens SGT6 gas turbines as compared to the three existing natural gas-fired power boilers. This leads to a reduction in greenhouse gas emissions, emitted per unit of electricity produced at the facility.

- CECP would displace less efficient peaking capacity in the dispatch order of gas-fired facilities that are required to provide electricity reliability in the local region.
- CECP would provide flexible, dispatchable power necessary to integrate the growing generation from intermittent renewable sources, such as wind and solar generation.
- CECP would facilitate to some degree the replacement of out-of-state, high GHG-emitting (e.g., coal) electricity generation that must be phased out to conform to the State's new Emissions Performance Standard.
- CECP would facilitate to some extent the replacement of generation provided by other aging power plants that use once-through cooling that are currently being used to provide necessary local power reliability, and could help facilitate/hasten to some extent the eventual permanent shutdown of all of the Encina and South Bay power boilers.

The project would reduce GHG emissions across the electricity system providing energy and capacity to California. Thus, 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 not result in impacts that are adverse or cumulatively significant. Moreover, the project is consistent with AB 32 goals.

The energy displaced by the CECP would result in a reduction in GHG emission from the electricity system. In other system roles, as described in **Greenhouse Gas Table 12**, CECP would minimize its GHG impacts by filling nearly all of the expected future roles for local gas-fired generation, in a high-renewables, low-GHG system.

Greenhouse Gas Table 12
CECP, Summary of Role in Providing Energy and Capacity Resources

Services Provided by Generating Resources	CECP Role:
Integration of Renewable Energy	• Would provide fast startup capability. • Would have ability to provide regulation and reserves, and energy when renewable resources are unavailable.
Local Generation Displacement	• Would be able to satisfy/partially satisfy local capacity area (LCA) resource requirements. • Would provide voltage support.
Ancillary Services, Grid System, and Emergency Support	• Would provide fast startup capability • Would have ability to provide regulation and reserves.
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).

RESPONSE TO AGENCY AND PUBLIC COMMENTS

The response to agency and public comments on the PSA Air Quality Section, including response to comments on **Appendix AIR-1 Greenhouse Gas Emissions**, are summarized in **Appendix AIR-2 Response to PSA Comments**. As indicated in **Appendix AIR-2**, a number of revisions were made to this Final Staff Assessment appendix as part of the response to the agency and public comments.

CONCLUSIONS

The Carlsbad Energy Center Project (CECP), as an addition to the California electricity system, would be a mid-merit/peaking power project that would operate primarily during periods of high local electricity demand and need for local grid reliability support. The CECP project would directly replace less efficient existing facilities with lower emissions of CO_2/MWh and would replace generation from other less efficient boiler or peaking facilities. The project's GHG emissions per MWh are expected to be lower than those of the generation that the project would displace and, thus, would contribute to continued improvement of the California and overall Western Electricity Coordinating Council system's greenhouse gas (GHG) emissions and GHG emission rate average. AB 32 emphasizes that GHG emissions reductions must be big picture reductions that do not lead to leakage of such reductions to other states or countries. If a gas-fired power peaking/mid-merit plant is not built in California, electricity to serve the load would come from another generating source.

This 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. The CECP would also provide other potential GHG benefits by filling nearly all of the expected future roles for local gas-fired generation, in a high-renewables, low-GHG system.

Staff notes that mandatory reporting of GHG emissions per Air Resource Board greenhouse gas regulations would occur, and this would enable the ARB to gather the information needed to regulate CECP in trading markets if required by the regulations implementing the California Global Warming Solutions Act of 2006 (AB 32). The project will be subject to reporting requirements and may become subject to GHG reductions or trading requirements as these requirements become 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, such as limiting idling times and requiring, as appropriate, equipment that meet the latest emissions standards, would further minimize greenhouse gas emissions since staff believes that the use of newer equipment 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 emissions from construction vehicles and equipment. For all these reasons, staff concludes that the short-term emission of greenhouse gases during construction would be sufficiently reduced and would, therefore, not be significant.

Since this power project would be permitted for less than a 60 percent annual capacity factor, and could be considered a peaking/mid-merit generating facility, it is not subject to the requirements of SB 1368 and the Emission Performance Standard. Regardless, the proposed project's CO_2 emissions would be well below the Emission Performance Standard.

PROPOSED CONDITIONS OF CERTIFICATION

No Conditions of Certification related to Greenhouse Gas emissions are proposed. The project owner would comply with mandatory ARB GHG emissions reporting regulations (California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.) and/or future GHG regulations formulated by the ARB, such as GHG emissions cap and trade markets.

REFERENCES

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

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CECP 2007a – Carlsbad Energy Center Project/T. Hemig (tn: 42299). Application for Certification for the Carlsbad Energy Center Project. 09/11/2007. Rec'd 09/11/2007.

SR 2007b – Stoel Rives/ J. McKinsey (tn: 43722) Response to Staff's Issues Identification Report. 12/13/2007.

SR 2007d – Stoel Rives/ J. McKinsey (tn: 43839) Response to Staff's Data Requests, Set 1. 12/20/07.

SR 2008a – Stoel Rives/K. Hellwig (tn: 45674) Data Response Set2 (#76 – 112). 3/18/2008.

SR 2008f – Stoel Rives/K Hellwig (tn: 46576) Data Responses, Set 2A (#113-124) to Staff's Data Requests, and Revised AQ Modeling files May 13, 2008. 6/05/2008.

SR 2008h – Stoel Rives/J McKinsey (tn: 47257) Project Enhancement and Refinement Document (12 copies); Effects on Bio Resources of Agua Hedionda Lagoon (4 copies); Revised AQ Modeling Files (6 CDs); Cal ISO Study Report. 7/25/2008.

APPENDIX AIR-2

Air Quality/Greenhouse Gas Comment Response

Testimony of William Walters, P.E.

INTRODUCTION

The agency and public comments on the CECP PSA Air Quality section and Appendix Air-1 Greenhouse Gases are provided below in the following order by commenting party. Some comments have been summarized for clarity and brevity.

- City of Carlsbad
- Power of Vision
- Kerry Siekmann
- California Unions for Reliable Energy
- Earthjustice

The FSA Air Quality section and Appendix Air-1 Greenhouse Gas Emissions have been updated as noted in the responses provided below.

CITY OF CARLSBAD 1/30/09 COMMENT LETTER

Comment Page 4 – PDOC Comments

The City provided extensive comments on the Preliminary Determination of Compliance to the San Diego Air Pollution Control District.

Staff Response

Comments noted. Staff has incorporated revisions as necessary from the District's FDOC in the FSA.

Comment Pages 4, 5 – I-5 Widening and Additional Project Information

Additional information regarding the I-5 widening and other CEC air quality staff requested information will be supplied from the applicant to the Energy Commission and the City anticipates commenting on these submittals.

Staff Response

Staff has incorporated the information from the I-5 widening and air quality submittals from the applicant as appropriate to complete the air quality FSA section. The City can provide comments on the FSA at the workshop and in writing.

Comment Page 5 – PSA Page 4.1-1

The CECP has indicated that the SDAPCD PDOC terms are unacceptable. Please indicate that the timing and content of an FDOC is uncertain.

Staff Response

The FSA has been published only after publication of the FDOC that has, to the extent the District considered reasonable, incorporated comments from CECP and other

parties including the CEC staff. CEC staff is satisfied with the content and conditions of the FDOC and has incorporated these conditions into the FSA.

Comment Page 5 – PSA Page 4.1-1

The City is unclear if the 60 percent capacity factor trigger for the SB 1368 Environmental Performance Standard would apply to each turbine individually or collectively.

Staff Response

The SB1368 definition of a power plant is as follows:

(l) "Power plant" means a facility for the generation of electricity, and is:
- (1) a single generating unit; or
- (2) multiple generating units that meet the following conditions:
  - (A) the generating units are co-located;
  - (B) each generating unit utilizes the same fuel and generation technology; and
  - (C) one or more of the generating units are operationally dependent on another.

This regulatory definition considers each combustion turbine and associated steam turbine to be a separate power plant unit for the purposes of SB1368. Therefore, the proposed project consists of two separate SB1368 power plant units – Carlsbad Unit 6 and Carlsbad Unit 7. Regardless, each CECP power plant unit would have CO_2 emission performance that would meet the EPS whether it needs to meet the EPS or not. See Appendix Air-1.

Comment Page 5 – PSA Page 4.1-22

The City notes that the applicant's proposed 24-hour construction work schedule is unacceptable and requests that the construction work schedule be revised to reflect City of Carlsbad Municipal Code 8.48.

Staff Response

Staff assumes this comment to mean that the City is asking staff to impose a Condition of Certification in the Air Quality FSA section to limit construction hours. However, staff notes that the cited Municipal Code section addresses noise impacts not air quality impacts. Compliance with this Municipal Code is properly addressed in the Noise Section of the PSA/FSA in Condition of Certification **NOISE-6**.

A worst-case 24-hour construction basis was assessed in the air quality analysis to be conservative in case 24-hour construction would occur either based on an exception granted as allowed in Section 8.48.020 of the Municipal Code, or on the basis that the construction activities that do occur outside of the hours listed in Section 8.48.010 of the Municipal Code would only be those that would not be done in a "manner as to create disturbing, excessive or offensive noise" that could violate the Municipal Code.

Comment Page 5 – PSA Page 4.1-25

Please confirm from the manufacturer that the emission performance for the CTGs is based on an emission smokestack of 139 feet.

Staff Response
Please see the response to Power of Vision Air Quality Comment 6 (second paragraph).

Comment Page 5 – PSA Page 4.1-27
The City is unclear as to what is the limiting factor of the CECP – air emissions or operating time. Please clarify.

Staff Response
The limiting annual operating characteristic for air quality is criteria pollutant emissions as limited by Air Quality Condition of Certification **AQ-44**. If this project is licensed, any changes to these limits would require formal approval from the District and the Energy Commission.

Comment Page 5 – PSA Page 4.1-97
The City disagrees with Staff's conclusion that the CECP would not result in a significant GHG cumulative impact. The CECP will produce more than 850,000 metric tons of CO2E per year, which greatly exceeds any threshold level currently contemplated for identifying significant GHG emitters.

Staff Response
Please see below for staff's responses to Earthjustice Consolidated GHG Analysis comments. Also, please see the revised **Appendix Air-1** analysis.

Comment Page 6 – PSA Pages 4.1-101, 102
Please adjust GHG Tables 2, 3, and 4 to reflect the information provided by the applicant in their January 26, 2009 data response, including the Encina Units 1-3 GHG emissions for 2007 and 2008 that are consistent with the reduced level during 2006 and significantly lower than the emissions produced in 2002-2005.

Staff Response
The Greenhouse Gas Table 2 has been revised to include the new and revised data from the applicant on construction GHG emissions. Greenhouse Gas Table 3 has been revised to include additional information on parasitic power demand and net MW generation for the proposed CECP. Greenhouse Gas Table 4 has been updated to include 2007 and 2008 historic GHG emission estimates and is now based on the same consistent data source (the Commission's Quarterly Fuel and Energy Report) as that used for all tables providing historic GHG emissions, capacity, and generation data.

Comment Page 6 – PSA Page 4.1-103
The City disagrees with the PSA statement that "the project would not result in a net increase in global GHG emissions". The applicant's data responses indicate that the project would serve new generation procurement needs of SDG&E and would therefore result in a net increase of GHG emissions of approximately 400,000 metric tons per year. The analysis should be amended to note this net GHG emission increase.

Staff Response
Staff has reviewed systemwide GHG emission impacts and has amended the GHG section to provide additional information to support staff's analysis and findings. We believe that the proposed CECP, with its direct and indirect replacement of generation from other less efficient higher GHG emitting fossil fuel fired generation sources, is necessary for the system integration of low GHG emitting renewable energy sources and would allow the reduction of systemwide GHG emissions.

Comment Page 6 – PSA Page 4.1-104
GHG Figure 1 is misleading as it does not show that total GHG emissions have been increasing over time. The core purpose of AB 32 is to reduce the gross amount of GHGs produced, which the CECP fails to achieve.

Staff Response
In staff's amended GHG analysis GHG Figure 1 has been removed. Also please see the response directly above relating to systemwide GHG emissions impacts.

Comment Page 6 – PSA Page 4.1-106
The City disagrees with the findings of the GHG cumulative impact section. The project represents a growth of energy capacity and thus GHG emissions. The cumulative impact section should be amended to reflect the project's GHG emissions increase.

Staff Response
Please see staff's amended GHG analysis and the response above to the City's GHG analysis comment on PSA page 4.1-103.

Comment Page 6, 7 – PSA Page 4.1-107
The City disagrees with the statements in the Noteworthy Public Benefits section of the GHG analysis. The City is more concerned with the total GHG emissions than emissions per MWh. The analysis should be amended to reflect that the project will increase GHG emissions by more than 400,000 metric tonnes per year.

Staff Response
The Noteworthy Public Benefits section has been amended with the rest of the GHG analysis with additional information and support of staff's overall findings for the proposed project. Staff does not believe when assessing global GHG impacts anything less than a system-wide GHG impact analysis is reasonable. Staff believes that this assessment must include the type of project and how it could/would operate, its relative GHG emission rate per MWh, and its overall system-wide impact. The total potential emissions of a specific power plant project considered in a vacuum are not relevant to determining the impacts for this global issue; the relevant assessment is the project's overall impact to the system.

Comment Page 7 – PSA Page 4.1-107
The CECP would be a significant emitter of GHG emissions under any threshold developed. The analysis does not include an analysis of the impacts of global warming such as rise of sea level, etc.

Staff Response
Please see the response to the Earthjustice Consolidated GHG Analysis comments.

The negative consequences of global warming are briefly noted in the Global Climate Change and Electricity Production section of the GHG analysis.

POWER OF VISION 1/30/09 COMMENT LETTER

Air Quality Comment 1
The summary of conclusions for greenhouse gases is misleading because, while the proposed CECP project is more efficient than the existing Encina Units 1-3, the proposed CECP project would likely operate considerably more than Encina Units 1-3 would and therefore would produce more greenhouse gas emissions.

Staff Response
The staff's finding has been clarified to note that the generation from the CECP would replace other dispatchable fossil-fuel fired generation, which would include Encina Units 1 through 3 and other existing resources such as South Bay and older area peaking power plants, that on average would have a higher GHG emission profile. Therefore, the CECP project would not result in a cumulative greenhouse gas impact. Additionally, dispatchable generation from low-GHG emitting projects such as CECP are necessary for the system-wide integration of non-dispatchable, intermittent renewable energy sources as their total capacity and percent of overall generation continue to rise.

Air Quality Comment 2
The applicant has not been able to provide adequate mitigation for NOx. This must be determined before permits are granted.

Staff Response
The FSA and the SDAPCD FDOC both detail the complete NOx mitigation proposal that has been provided by the project applicant.

Air Quality Comment 3
The plant should meet the same NOx emissions requirements (without the applicant requested waivers for transient load operations) as permitted for other similar power plants.

Staff Response
The SDAPCD has not allowed the applicant's request for significantly increased NOx emissions during transient load operation, and have only allowed an increase in the compliance period from a one-hour average to a three-hour average during transient load operation. Staff concurs with the District and has provided additional information about the request for transient load emission levels and the District's denial of the applicant's request in the FSA.

Air Quality Comment 4
The applicant should provide actual data for the same plant as proposed for this project and under the same modes of operations (Staff notes this is a follow-up of Air Quality Comment 3).

Staff Response
Actual data for this type of plant/turbine in commercial operation does not yet exist. Please also see the response to Comment 3 directly above.

Air Quality Comment 5
Please account for increase in greenhouse gas emissions; mitigation requirements and health effects on surrounding residents

Staff Response
The exact intent of this comment is not clear; however, as noted in the FSA staff does not believe that this project, as a very efficient dispatchable power source, would cause an increase in greenhouse gas emissions system-wide. Greenhouse gas mitigation requirements for the power sector that may be required by ARB as they develop AB 32 requirements are not currently known. However, they might include a cap and trade system that would likely include this facility. Greenhouse gas pollutants are not toxic air pollutants and would not have significant direct, localized health impacts on surrounding residents at the concentrations emitted by the facility. The health impacts of the toxic air pollutants are separately described in the Public Health section of the FSA.

Air Quality Comment 6
The maximum annual project NOx emissions and NOx emission reduction credit given for the shutdown of Units 1, 2, and 3 are both suspect, should be reviewed and should be based on 2004 through 2008 rather than 2002 through 2006.

It is not clear if the Siemens emission guarantee applies for the proposed stack height of 139 feet that is set 40 feet down in a depression.

Staff Response
The dates for the emission calculation for emission netting purposes under SDAPCD New Source Review regulations for Encina Units 1 through 3 are tied to the original permit application submittal date which occurred in 2007, so 2002 through 2006 is the appropriate time period for determination of the baseline emissions for Encina Units 1 through 3. The District has performed a significant re-analysis of the emission baseline and has revised the baseline in the FDOC. Staff has reviewed the FDOC and finds that the District's baseline re-analysis is comprehensive and complete.

The exact stack height, the proposed change to the stack height, and fact that the facility is located in a slight depression do not impact the turbine operations, the control technology effectiveness, or the gas turbine emissions guarantees. The stack height was raised from 100 to 139 feet by the applicant solely to meet physical design requirements for testing port locations to comply with EPA stack testing regulations.

Air Quality Comment 7
The methodology for meeting the staff recommended PM10/PM2.5 and VOC emission offsets needs to be determined and the offsets should occur prior to issuance of the FSA.

Staff Response
Staff has accepted the applicant's proposal to offset these emissions by using existing held emission reduction credits and creating new emission reductions funded as specified in staff recommended Condition of Certification **AQ-SC10**. The FSA details staff's review and findings on this CEQA offset mitigation proposal.

Air Quality Comment 8
The license should add a condition that requires the project be subject to the requirements of SB 1368 if it ever exceeds a 60 percent capacity factor in any rolling twelve month period.

Staff Response
A condition regarding compliance with the SB 1368 Emission Performance Standard (EPS) is not required for this project as it has specific operating limitations that would not allow the facility to have an annual capacity factor above the 60 percent trigger level to define it as a base load facility. If at any time in the future the project owner were to want to expand operating limits, they would have to come before the commission to amend their license. At that time the Energy Commission staff would analyze all greenhouse gas regulations then in force and would require adding appropriate conditions to the license. However, as noted in the FSA, this proposed project would have CO_2 emissions well below the SB 1368 EPS requirements due to its efficiency and fuel type.

KERRY SIEKMANN 1/29/09 COMMENT LETTER

Page 1 Comment 1
The proposed CECP Facility and remaining Encina boilers would create one large facility that should fall under the requirements of SB 1368.

Staff Response
SB 1368 regulations are clear that the CECP and Encina Units are not considered to be a combined power plant. The SB1368 definition of a power plant is as follows:

(l) "Power plant" means a facility for the generation of electricity, and is:
- (1) a single generating unit; or
- (2) multiple generating units that meet the following conditions:
  - (A) the generating units are co-located;
  - (B) each generating unit utilizes the same fuel and generation technology; and
  - (C) one or more of the generating units are operationally dependent on another.

This regulatory definition considers each combustion turbine and associated steam turbine to be a separate power plant unit for the purposes of SB1368. Therefore, the proposed project consists of two separate SB1368 power plant units – Carlsbad Unit 6

and Carlsbad Unit 7.The CECP and existing Encina Units (Encina 4 and 5) would also not be defined as the same power plant under SB 1368 because they do not use the same generation technology and they are not operationally dependent.

Even if staff could consider the CECP and the Encina boilers as a single power plant for the purposes of SB 1368 compliance, the emission performance standard would not apply to this combined facility as it would not have a capacity factor above 60 percent.

Page 1 Comment 2
The PSA does not mention in the climate description (p. 4.1-4,5) or appear to evaluate important meteorological conditions such as the persistent marine layer and fog conditions that occur on the coast.

Staff Response
Staff has clarified the climate description on p. 4.1-5 in the FSA to include additional information regarding the local climate phenomena as well as providing additional information about the coastal meteorological data set used to evaluate local impacts from the project and it appropriateness to evaluate such phenomena. The meteorological data used to assess impacts is from Oceanside, within 6.5 miles of the project site, at a location that is approximately one-half mile from the surf zone and within one-third mile from the I-5 freeway. These characteristics are very similar to and representative for assessing impacts from the CECP project operation. Additionally, the potential impacts from short-term inversion breakup and shoreline fumigation events were evaluated separately (see **Air Quality Table 24**).

Page 1 Comment 3
The San Diego Air Basin is nonattainment of state and federal ozone standards and state PM10 and PM2.5 standards. The CECP will increase these pollutants in the neighborhoods surrounding the site, which will impact the health of the area residents. How can the CEC approve projects that increase emissions in an area surrounded by neighborhoods?

Staff Response
Staff reviews applications that are submitted to determine if they would comply with all laws, ordinances, regulations, and standards (LORS) and determine whether the project would create significant air quality impacts. In many if not most power plant siting cases there are neighborhoods nearby the proposed project. In many of these siting cases, the existing air quality is considerably worse than it is in Carlsbad, such as in the Los Angeles Basin or San Joaquin Valley. In the case of this project, staff has found that the project would comply with all LORS and would not create significant air quality impacts.

Staff acknowledges that the San Diego Air Basin is in non-attainment of the federal ozone, and state ozone and PM10/PM2.5 standards and has recommended emission mitigation measures, above and beyond those required by the San Diego Air Pollution Control District, that staff considers appropriate due to the nonattainment status of the air basin. The proposed project analyzed by staff includes mitigation in the form of emission reductions, both onsite (shutdown of Units 1-3) and offsite (District ERCs), as

well as additional local emission reductions recommended by staff to be funded by the applicant.

The health risk assessment for the project in the Public Health section of the FSA shows that the local health impacts to area residents are below all health based significance standards endorsed by the California State Office of Environmental Health Hazard Assessment (OEHHA).

Page 1 Comment 4
Has the analysis included assessment of worst-case emissions of proposed Units 6 and 7 along with worst-case emission of existing Units 4 and 5 along with worst-case emissions from the I-5 during rush hour cumulatively, as required by CEQA?

Staff Response
Yes, the modeling analysis has included an assessment of the cumulative impacts of the new proposed CECP emission sources, along with the existing Encina units 4 and 5, along with worst-case ambient pollutant background conditions (see **Air Quality Table 27**). In the Air Quality PSA this table just reported short-term impacts for NOx and CO, but in the Air Quality FSA, Table 27 has been amended to include all relevant Ambient Air Quality Standards and averaging periods.

Page 1 Comment 5
Is it appropriate to use Oceanside for background CO levels, considering the local CO impacts of the I-5 during rush hour and the existing Encina plant, for the modeling of startup and shutdown worst-case CO impacts for proposed CECP Units 6 and 7?

Staff Response
The background CO concentrations, and PM10 and PM2.5 background concentrations, used in the PSA were collected at the Escondido monitoring station, a valley monitoring located near the I-15 and Hwy 78. These data are considered conservative in comparison with the coastal project location. Camp Pendleton (i.e. Oceanside) monitoring data were used for NO_2 background concentrations, because that is the only criteria pollutant currently monitored at the Camp Pendleton monitoring station.

Using **Air Quality Table 7** to compare the available older Oceanside CO ambient monitor data (1990-1998) with the more recent Escondido CO ambient monitor data (1999-2007) clearly shows that the coastal CO concentrations around the project site can be expected to be lower than the CO background concentrations taken from the Escondido site. Staff also notes that CO ambient air quality exceedances would not have been predicted for any operating scenario of the CECP regardless which site was used for background CO concentrations. Additionally, the significant improvements in CO emissions from automobiles, which are the primary source of CO emission impacts, will continue over time reducing CO background concentrations throughout San Diego and California.

In all of the air dispersion modeling cases, other than selected refined NO_2 modeling analyses noted in the FSA, the worst-case ambient concentration for a specific pollutant and time frame (such as CO for one-hour) over a three year period was used as the

background even though the specific meteorological conditions that occurred during the worst-case ambient background period would not match the meteorological conditions necessary for the worst-case project emission impacts. This conservative approach provides a measure of safety in determining whether there would be any localized significant impacts from the project.

Page 1 Comment 6

Is it appropriate to use Camp Pendleton Oceanside for background NO_2 levels, considering the distance from the project site and the fact that the Encina stack is 400 feet and the CECP stack is 300 feet shorter?

Staff Response

The Camp Pendleton monitoring station is considered representative as it is near the I-5 freeway (within 1/3 mile) and has both nearby marina and Camp Pendleton mobile emission sources (including on-road and off-road vehicles of many types that do not have or need to meet California on-road or off-road emission standards) that will influence the worst-case ground level NO_2 concentrations. Considering all of these factors, the Camp Pendleton monitoring location is considered a reasonable source of data for background NO_2 concentrations.

Additionally, as noted above in the response to Comment 4, the cumulative NO_2 and other pollutant impacts from the CECP and the Encina Power Station, including the ambient background concentrations, were assessed and were found not to create new exceedances or significantly contribute to existing exceedances of ambient air quality standards.

Finally, the modeling analysis considers the actual stack height and all of the other stack parameters for all of the modeled CECP and Encina Power Station emission sources.

Pages 1, 2 Comment 7

The 400 foot height of the Encina stack disperses emissions from the existing plant which has also reduced fuel oil use in favor of natural gas use that has reduced impacts from the existing facility. The ambient measurement tables in the PSA are based on this 400 foot tall stack, while the emissions from the CECP will be emitted out of stacks only 100 feet above ground level. Doesn't this mean the historical data used for modeling is inappropriate since it is based on a stack four times higher than the CECP stacks?

Staff Response

The only historical data used in the air dispersion modeling analysis is the selected worst-case background concentrations, which included the effects of fuel oil firing at Encina Units 1 -5. Staff believes that the selected worst-case background concentrations used in the modeling analysis are appropriate and conservative (see responses to Comments 5 and 6). Additionally, the modeling analysis inputs include the actual stack heights and included the Encina stack emissions (and included an oil firing case, even though only natural gas firing is currently permitted to be used at Encina Units 4 and 5) along with the CECP stack emissions in a cumulative modeling analysis. The use of worst-case background concentrations plus the worst-case impacts from the

CECP and Encina stacks combined provide a very conservative basis to predict the worst-case localized impacts.

Page 2 Comment 8

The operation of Units 1, 2, and 3 at the Encina power station has declined in recent past years. Wouldn't the past two years be more appropriate for the San Diego Air District to use to calculate the proposed CECP 6 and 7 pollution credits?

Staff Response

First, staff notes that while we have commented on certain specifics of the PDOC, we do not argue the general appropriateness of the District's regulations that are approved both by CARB and U.S.EPA to implement the state and federal Clean Air Acts, including the those regulations that cover methods of how to calculate net emission changes. The District addressed Energy Commission staff's comments and concerns regarding this issue during the discovery phase of the project and has dealt with the emission estimation basis issues for years 2002 and 2003 and has painstakingly gone over the emission estimates, including the most recent proposed reductions in the NOx emission estimate provided by the applicant, to determine the appropriate emission reductions from the closure of Encina Units 1, 2, and 3.

Second, NRG could have operated Units 1, 2, and 3 to the exclusion of Units 4 and 5 to significantly increase their baseline emissions for these units after they knew they were going to propose the CECP, but they did not.

Third, it is possible that Encina Units 1, 2, and 3 would need to increase its capacity factor and emissions in the future, at least for some period of time, if the CECP or other proposed new power plants were not built.

Finally, staff is in agreement with the methods that the District used to determine the emission baseline for Units 1, 2 and 3.

Page 2 Comment 9

Greenhouse Gas Table 3 shows 846,076 metric tons per year of greenhouse gas emissions while Encina Units 1-3 only emitted 162,545 metric tons in 2006. This is a large emission increase and greenhouse gas emissions are a grave concern.

Staff Response

These two values should not be compared directly as the first value is the permitted maximum GHG emissions for the CECP while the second is the actual annual GHG emission for Encina Units 1-3 during 2006. While staff recognizes that the CECP, if licensed, would almost certainly operate more than Encina Units 1-3, it is not known at what proportion of its permitted capacity it will actually operate over project life. For comparison purposes, the maximum GHG emission potential for Encina Units 1-3, based on permit limitations, is approximately 1,650,000 metric tons per year[1], or about twice the potential for CECP; and the GHG emission performance of these units is

[1] This is based on the assumption that the emission performance for Units 1-3 would be reduced to approximately 0.600 MT CO2E/MWh if operated at its highest efficiency at maximum permitted output and capacity.

calculated to be 0.637 metric tons CO2E/MWh averaged over 2002 to 2008, which is approximately 50 to 55 percent higher than the CO2E/MWh for the proposed CECP, which is 0.405 metric tons CO2E/MWh.

Please also see the response to the Earthjustice Consolidated GHG Analysis comments and the response to Comment 10 directly below.

Page 2 Comment 10
The net GHG emission performance, noted to be 0.405 MTCO2E/MWh in the PSA, does not include the power consumption of the desalination plant.

Staff Response
Staff has corrected the net MWh assumption to include the power generation from the steam injection power augmentation system and the power consumption of the desalination unit (estimated to be 1,236 MWh), which has revised the net GHG emission performance from 0.4046 to 0.4049 MT CO2E/MWh. This is a very small increase, and both values round to 0.405 MT CO2E/MWh.

Page 2 Comment 11
The construction emissions will occur over a long period for this project and will impact the children and elderly living in the local neighborhoods that surround the project site.

Staff Response
Staff evaluated the construction emission impacts for both the potential short-term peak and annual criteria pollutant concentrations, as well as evaluated the acute and long-term chronic and carcinogenic health impacts from air toxics in the Public Health Section of the PSA.

In response to the potential impacts from construction, including localized PM impacts and regional ozone impacts, staff recommends extensive construction mitigation measures including both fugitive dust control measures and off-road equipment engine emission control measures that will significantly reduce the emission potential from the project's construction. With implementation of these mitigation measures, measures that are much more extensive than those typically required outside of the Energy Commission process, and the required full-time onsite compliance monitoring, staff has found that there would be no significant impacts to local area residents resulting from the project's construction emissions.

Page 2 Comment 12
The CECP will increase air pollution in Carlsbad and is not needed to be located near the coast, as was the case for the existing Encina Plant with its once-through cooling, so an alternative project location rather than this location should be found.

Staff Response
Staff recognizes that the project, taken alone, would increase air pollution in area surrounding the project site, as it would around any alternative project site location. However, staff did not find that the proposed project's contributions to ambient pollutant

levels, after mitigating the emission increases for all non-attainment pollutants and their precursors, would create significant air quality impacts.

Additional response to comments on the project alternatives analysis are included in the updated Alternatives Section of the FSA.

CALIFORNIA UNIONS FOR RELIABLE ENERGY 1/29/09 AND 1/30/09 COMMENT LETTERS

Note: There are five essentially identical air quality comment topics listed in the 1/29/09 and 1/30/09 comment letters. The numbering and title of the comments is based on the format provided in the 1/29/09 comment letter.

Comment I. Definition of Startup Period

The definition of a startup period is flawed as it does not address the variability in the startup period that will occur depending on turbine and HRSG temperatures (hot, warm, cold) and is overly lenient based on the turbine manufacturer data in the AFC that shows a startup interval of 22 minutes. More information is necessary to assess unit startups under all startup scenarios (hot, warm, cold) to provide more stringent startup time limits during which the turbines do not have to meet the 2 ppm NOx emission limit.

Staff Response

The Siemens manufacturer startup data is an estimate and not a guarantee as noted in the AFC; therefore, the applicant has provided safety margins in the duration and event emissions that they are willing to stipulate to as adequate to guarantee compliance under all non-upset, normal startup scenarios. Typical startup periods for Frame F gas turbines range from 90 minutes to 6 hours, depending on the type of start with permitted startup event emissions that are several times, if not an order of magnitude, higher than the startup event emissions proposed for the CECP gas turbines. Additionally, District condition **AQ-49** would require that the SCR system ammonia injection system be operating as soon as the outlet of the SCR reaches 450°F which would effectively start the control of NOx emissions regardless of the difference in duration of the startup based on whether it is a hot/warm/cold start. Therefore, staff believes that the startup emissions and SCR operating requirements are limited appropriately regardless of the type of startup, and additional conditions or emission limits for hot/warm/cold starts are unnecessary for this rapid response gas turbine.

Comment II. Number of Startup and Shutdown Events

The number of startups and shutdowns in the permit conditions do not match the emission calculation basis. The potential for significantly increased startup/shutdown emissions and their potential to dominate the total allowed annual emissions and reduce allowed normal operating time is a concern, so the startup/shutdown emissions should be limited in a revised condition.

Staff Response

Staff considers the annual emission limit to be the overriding limitation on annual operations. The amount of startup/shutdown events and normal operating hours are not considered fixed numbers, just values used to determine the annual emissions limits.

The actual operation of CECP will be required to meet (i.e., will be limited by) the annual emission limits, regardless of variation with these startups events and operations hours. Condition **AQ-47** was written by the District to provide a very high limit on the number of starts and stops. However, economics will dictate how the facility is actually operated while maintaining annual emission below the conditioned annual emissions limits. The impact analysis considered all of the appropriate short-term emission events such as startup and shutdown. Staff does not believe any additional conditions are necessary.

Comment III. Transient Load Changes

The request from the applicant for increased emission limits during load transients are a concern and additional information regarding these emissions and the potential for load transient events to exceed the applicant's proposed 15 hours per year needs to be evaluated.

Staff Response

Please see the response to Power of Vision Air Quality Comment 3.

Comment IV. Rapid Response Startup and Shutdown Times

The startup and shutdown periods and emissions for the El Segundo Redevelopment project, using the same rapid response turbine technology as the CECP, are different than those proposed for the CECP. This discrepancy needs to be explained.

Staff Response

Staff recognizes that there are differences between the El Segundo and CECP gas turbine startup information. However, the startup interval information provided by the applicant for this case clearly comes from Siemens (Table 5.1B-8 of the AFC Appendix 5.1B). The reason for the difference in the cases could be due to revised estimates by Siemens, differences in the combustors or other gas turbine design parameters, or other unknown factors. Regardless, neither set of manufacturer's data was given as a guarantee, so the applicant has provided safety margins to the startup interval and emission limits to which it is willing to stipulate.

Also, please see the response to Comment II. provided above.

Comment V. Secondary PM10 Emissions

The PSA states that PM10 emissions "are not estimated to be higher or lower during startup and shutdown events than during normal operations". However, PM10 precursor emissions (NOx) are higher during startup, so the applicant should be required to quantify the potential formation of secondary particulate and the information should be incorporated in the PSA.

Staff Response

In the citation, the PSA is referring to the stack emissions of PM10, not to the secondary PM10 formation that will be occur after stack exhaust is released into the atmosphere. Also, staff notes that PM10 emissions during startup and shutdown events are likely to be lower than normal operations, and other applicants have assumed fuel use proportionality for their PM10 emissions during startup and shutdown events, which has not been assumed for this project.

Secondary particulate formation is discussed in the PSA (see pages 4.1-40, 41). The specific amount of secondary particulate formation cannot be reasonably estimated, either during short-term startup events or over the long term, due to the complexity of the reactions that cause secondary particulate formation and the variability of the ambient conditions that influence this process.

Through a combination of the District required NOx offsets; the shutdown of Encina Units 1, 2, and 3; and staff's required offsets for PM10 and VOC there will be no permitted emission increases of particulate emission or criteria pollutant particulate precursor emissions.

EARTHJUSTICE 1/30/09 AND 2/6/09 COMMENT LETTERS

Consolidated GHG Analysis Comments

A) The greenhouse gas significance finding is misplaced and contrary to CEQA. ARB has proposed that emissions of more than 7,000 tons of GHG for an industrial facility are significant.

B) Staff's impact assessment methods are flawed and should conform to other projects as identified in case law[2]. The CECP's higher efficiency than the retired boilers and other existing power plants does not address the CECP's impacts over the next forty years and the opportunity for project alternatives to reduce the GHG impacts.

C) The dependence on AB 32 as the proper forum to address GHG emissions for the project and using the SB 1368 EPS as a significance criteria are flawed and do not address the impacts for the life of the project. AB 32 only regulates emissions through 2020 and compliance with the SB 1368 EPS is not an appropriate significance criteria.

D) The GHG emission estimate for the CECP is incomplete and should include lifecycle emissions.

E) Construction GHG emission impacts are improperly dismissed.

F) The CECP will supplement future growth in energy use. Feasible mitigation and alternatives should be adopted.

G) Impacts of Global Warming on the CECP are not analyzed.

Staff Response

A) This issue is very complex for the power generating sector since the proposed plans for GHG reduction for the sector include not just the integration of renewable resources and increased energy efficiency, but also relies on the replacement of older fossil-fuel fired resources with newer, more efficient fossil-fuel fired resources, as well as the implementation of future AB 32 regulations that will require overall reductions in this sector's GHG emissions. Staff's GHG impacts findings are consistent with CEQA

[2] Several lawsuits were cited by Earthjustice, none of which concern power plants.

requirements. GHG impacts are a global impact, not a local impact, and staff has assessed the project in its system-wide global context as appropriate for this global impact.

The CEQA Lead Agency for this project is the Energy Commission. The ARB document that is cited but not referenced in this comment is a preliminary draft document from the ARB. This document, the *Recommended Approaches for Setting Interim Significance Thresholds for Greenhouse Gases under the California Environmental Quality Act* (ARB 2008x), specifically notes the following:

> ARB staff's proposed recommendations for GHG thresholds address projects for which local agencies are typically the CEQA lead agency. In addition to the CEC, other State agencies also serve as lead agencies under CEQA. ARB is coordinating with these State agencies on their approaches to thresholds of significance.

So it is clear that this ARB document's draft significance thresholds are not relevant to power plant projects.

B) The lawsuits cited in this comment are in fact not analogous to the CECP project. The CECP project is both a replacement project and is part of a whole interconnected sector, which needs dispatchable resources for integration of renewable energy. The CECP project will be regulated as part of the whole electricity generation sector-wide GHG emission reductions. This is certainly not the case for residential and commercial projects that were the subjects of the cited lawsuits. Therefore, staff believes the lawsuits cited in the comments are not applicable to the CECP and thus the arguments are likewise not applicable.

C) Staff has provided additional information to justify the GHG CEQA findings for the proposed CECP project in FSA, which we believe provides substantial evidence to make the conclusion that the project has a less than significant impact on climate change. While AB 32 and compliance with the SB 1368 EPS are discussed, they are discussed as LORS compliance issues and are not the basis for the significance determination.

D) Staff believes the emission estimates provided for the project are adequate for the system-wide impact analysis that uses the same emission estimate basis. If a lifecycle emission estimate were to be performed, which staff believes would have to rely on unreliable speculative assumptions, that similar life-cycle analysis would have to be performed system-wide, which would result in the same overall conclusion regarding GHGs.

E) Staff continues to conclude that the construction GHG emissions are negligible and not significant after implementation of best practices for construction. In comparison with the project's operating emissions, even if they were all applied to the first year of operation, and that first year of operation is limited to one-half of maximum permitted operating levels, the increase in GHG emission would be less than 0.5 percent.

F) Staff believes that the CECP will do more than supplement future growth in energy use. It will provide a lower emitting option than the existing boiler and peaker facilities and with its rapid response capability it will help with the system-wide integration of renewable energy sources. The CECP does not serve to stop deployment of expanded energy conservation, other energy use reductions or other GHG mitigation measures.

G) No impacts of Global Warming to the CECP site are expected. The site is surrounded by an area that is approximately 50 feet above sea level, with the lowest point 30 feet above sea level. Staff is not aware of any forecasts in sea level rise anywhere near 30 feet over the next 40 or so years of the project's proposed life.

2/6/09 Letter Page 5 Comment.
Staff should incorporate into their air analysis the new proposed moderate designation of the San Diego Air Basin for the 8-hour ozone National Ambient Air Quality Standard.

Staff Response
Staff has incorporated the proposed revision in the federal 8-hour ozone nonattainment designation into the setting of the air quality section of the FSA.

WORKER SAFETY AND FIRE PROTECTION

Testimony of Alvin J. Greenberg, Ph.D. and Rick Tyler

SUMMARY OF CONCLUSIONS

Staff concludes that if the applicant for the proposed Carlsbad Energy Center Project (CECP) provides a Project Construction Safety and Health Program and a Project Operations and Maintenance Safety and Health Program, as required by Conditions of Certification **WORKER SAFETY-1**and **-2** and fulfils the requirements of Conditions of Certification **WORKER SAFETY-3** through **-9**, the project would incorporate sufficient measures to ensure adequate levels of industrial safety and comply with applicable laws, ordinances, regulations, and standards. The proposed conditions of certification provide assurance that the Construction Safety and Health Program and the Operations and Maintenance Safety and Health Program proposed by the applicant would be reviewed by the appropriate agencies before implementation. The conditions also require verification that the proposed plans adequately assure worker safety and fire protection and comply with applicable laws, ordinances, regulations, and standards.

The Carlsbad Fire Department has stated that its ability to respond during a major crisis may very well be impacted by the operation of this power plant. Staff has thoroughly reviewed this matter, listened to comments from the applicant and the Carlsbad Fire Department, encouraged the applicant and the fire department to meet (which they did), and has reviewed written comments and reports on this matter. Staff has also conducted an initial assessment and after consideration of all information available to date, particularly the applicant's Fire Needs Assessment (SR 2008t), staff has determined that while this project may have an impact on the fire department's ability to respond to a fire or other emergency under unique catastrophic circumstances, the potential for impact is below staff's level of significance**.** Therefore, staff agrees with the applicant that mitigation is not required.

The applicant has indicated that the CEPC will be operated remotely from a control room on the adjacent Encina Power Station (EPS) site. For the reasons stated in this assessment, staff believes that a combined-cycle power plant cannot be operated safely and effectively from a remote location and thus proposes a Condition of Certification that would require the project owner to ensure that, at a minimum, two workers are always present on the below-grade CEPC site when the power plant is operating.

INTRODUCTION

Worker safety and fire protection is regulated through laws, ordinances, regulations, and standards (LORS), at the federal, state, and local levels. Industrial workers at the facility operate equipment and handle hazardous materials daily and may face hazards that can result in accidents and serious injury. Protection measures are employed to eliminate or reduce these hazards or to minimize the risk through special training, protective equipment, and procedural controls.

The purpose of this final Staff Assessment (PSA) is to assess the worker safety and fire protection measures proposed by the CECP and to determine whether the applicant has proposed adequate measures to:

- comply with applicable safety LORS;
- protect the workers during construction and operation of the facility;
- protect against fire; and
- provide adequate emergency response procedures.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

Worker Safety and Fire Protection Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
Title 29 U.S. Code (USC) section 651 et seq (Occupational Safety and Health Act of 1970)	This act mandates safety requirements in the workplace with the purpose of "[assuring] so far as possible every working man and woman in the nation safe and healthful working conditions and to preserve our human resources" (29 USC § 651).
Title 29 Code of Federal Regulation (CFR) sections 1910.1 to 1910.1500 (Occupational Safety and Health Administration Safety and Health Regulations)	These sections define the procedures for promulgating regulations and conducting inspections to implement and enforce safety and health procedures to protect workers, particularly in the industrial sector.
29 CFR sections 1952.170 to 1952.175	These sections provide federal approval of California's plan for enforcement of its own Safety and Health requirements, in lieu of most of the federal requirements found in 29 CFR sections 1910.1 to 1910.1500.
State	
Title 8 California Code of Regulations (Cal Code Regs.) all applicable sections (Cal/OSHA regulations)	These sections require that all employers follow these regulations as they pertain to the work involved. This includes regulations pertaining to safety matters during construction, commissioning, and operations of power plants, as well as safety around electrical components, fire safety, and hazardous materials use, storage, and handling.
24 Cal Code Regs. section 3, et seq.	This section incorporates the current addition of the Uniform Building Code.
Health and Safety Code section 25500, et seq.	This section presents Risk Management Plan requirements for threshold quantity of listed acutely hazardous materials at a facility.
Health and Safety Code sections	These sections require a Hazardous Material Business Plan detailing emergency response plans for hazardous materials

25500 to 25541	emergency at a facility.
Local (or locally enforced)	
CaliforniaFire Code 2007	The fire code contains general provisions for fire safety, including requirements for proper storage and handling of hazardous materials and listing of the information needed by emergency response personnel. Enforced by the Carlsbad Fire Department.
National Fire Protection Association standards	These standards provide specifications and requirements for fire safety, including the design, installation, and maintenance of fire protection equipment. Enforced by the Carlsbad Fire Department.

SETTING

The proposed facility would be located in the city of Carlsbad within an industrial area that is currently served by the local fire department. Fire support services to the site would be under the jurisdiction of the city of Carlsbad Fire Department (CFD). There are a total of six fire stations within the city of Carlsbad. The closest station to the CECP site would be Station #1, located at 1275 Carlsbad Village Drive, approximately 1.7 miles away. The total response time from the moment a call is made to the point of arrival at the site would be approximately 6 minutes (CECP 2007a, § 5.16.4.5). The next closest station would be Station #4, located at 6885 Batiquitos Drive, about 3.7 miles away, which would respond within 7 to 8 minutes (CFD 2008).

The CFD would also be the first responder to incidents involving hazardous materials, with backup support provide by a U.S. Marine Corp unit based at Camp Pendleton, and/or the San Diego City and County Hazardous Materials Incident Response Team (DEH-HIRT). According to the DEH-HIRT, it is capable of handling any hazardous materials-related incident and would have a minimal response time of one hour (CECP 2007a, §§ 5.10.3.6.2 and 5.10.3.6.3, and CFD 2008). All CFD firefighters (except one) are trained paramedics (CFD 2008).

Worker Safety and Fire Protection Table 2
Equipment and Personnel at Carlsbad Fire Department*

CFD Station	Total Response Time**	Distance to CECP	EMS/HazMat Capability***
Station #1	6 min	~1.7 miles	Y/Y
Station #4	7-8 min	~3.7 miles	Y/Y

*Source: phone conversation with Fire Marshal Weigand (CFD 2008).
**Total response times are estimated from the moment a 911 call is made to arrival at the site and are dependent upon traffic conditions and other variables.
***All personnel are trained to EMT-1 level and first responder for hazardous materials incidents, and all except one personnel are trained paramedics.

In addition to construction and operations worker safety issues, the potential exists for exposure to contaminated soil during site preparation. The Phase I Environmental Site

Assessment conducted for this site in 2007 concluded that the areas beneath existing structures may have environmental conditions that would require remediation and that this should be assessed during the time these structures are removed (CECP 2007a, § 5.14.3.1.1). To address the possibility that soil contamination would be encountered during construction of the CECP, proposed Conditions of Certification **Waste-1** and **Waste-2** require a registered professional engineer or geologist to be available during soil excavation and grading to ensure proper handling and disposal of contaminated soil. See the staff assessment section on **WASTE MANAGEMENT** for a more detailed analysis of this topic

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Two issues are assessed in **Worker Safety-Fire Protection**:

1. the potential for impacts on the safety of workers during demolition, construction, and operations activities, and

2. fire prevention/protection, emergency medical response, and hazardous materials spill response during demolition, construction, and operations.

Worker safety issues are thoroughly addressed by Cal/OSHA regulations. If all LORS are followed, workers will be adequately protected. Thus, the standard for staff's review and determination of significant impacts on workers is whether or not the applicant has demonstrated adequate knowledge about and dedication to implementing all pertinent and relevant Cal/OSHA standards.

Regarding fire prevention matters, staff reviews and evaluates the on-site fire-fighting systems proposed by the applicant and the time needed for off-site local fire departments to respond to a fire, medical, or hazardous material emergency at the proposed power plant site. If on-site systems do not follow established codes and industry standards, staff recommends additional measures. Staff reviews and evaluates the local fire department capabilities and response time in each area and interviews the local fire officials to determine if they feel adequately trained, manned, and equipped to respond to the needs of a power plant. Staff then determines if the presence of the power plant would cause a significant impact on a local fire department. If it does, staff will recommend that the applicant mitigate this impact by providing increased resources to the fire department.

Staff has also established a procedure when a local fire department has identified either a significant incremental project impact to the local agency or a significant incremental cumulative impact to a local agency. Staff first conducts an initial review of the position and either agrees or disagrees with the fire department's determination that a significant impact would exist if the proposed power plant is built and operated. A process then starts whereby the project applicant can either accept the determination made by staff or refute the determination by providing a Fire Needs Assessment and a Risk Assessment. The Fire Needs Assessment would address fire response and equipment/staffing/location needs while the Risk Assessment would be used to

establish that while an impact to the fire department may indeed exist, the risk (chances) of that impact occurring and causing injury or death is less than significant.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Worker Safety

Industrial environments are potentially dangerous during construction and operation of facilities. Workers at the proposed CECP would be exposed to loud noises, moving equipment, trenches, and confined space entry and egress problems. The workers may experience falls, trips, burns, lacerations, and numerous other injuries. They have the potential to be exposed to falling equipment or structures, chemical spills, hazardous waste, fires, explosions, and electrical sparks and electrocution. It is important for the CECP to have well-defined policies and procedures, training, and hazard recognition and control at its facility to minimize such hazards and protect workers. If the facility complies with all LORS, workers will be adequately protected from health and safety hazards.

A Safety and Health Program would be prepared by the applicant to minimize worker hazards during construction and operation. Staff uses the phrase “Safety and Health Program” to refer to the measures that would be taken to ensure compliance with the applicable LORS during the construction and operational phases of the project.

Construction Safety and Health Program

CECP encompasses construction and operation of a natural gas fired-facility. Workers would be exposed to hazards typical of construction and operation of a gas-fired simple cycle facility.

Construction Safety Orders are published at Title 8 California Code of Regulations sections 1502, et seq. These requirements are promulgated by Cal/OSHA and would be applicable to the construction phase of the project. The Construction Safety and Health Program would include the following:

- Construction Injury and Illness Prevention Program (8 Cal Code Regs. § 1509)
- Construction Fire Prevention Plan (8 Cal Code Regs. § 1920)
- Personal Protective Equipment Program (8 Cal Code Regs. §§ 1514 — 1522)
- Emergency Action Program and Plan

Additional programs under General Industry Safety Orders (8 Cal Code Regs. §§ 3200 to 6184), Electrical Safety Orders (8 Cal Code Regs. §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 Cal Code Regs. §§ 450 to 544) would include:

- Electrical Safety Program
- Motor Vehicle and Heavy Equipment Safety Program
- Forklift Operation Program
- Excavation/Trenching Program
- Fall Protection Program

- Scaffolding/Ladder Safety Program
- Articulating Boom Platforms Program
- Crane and Material Handling Program
- Housekeeping and Material Handling and Storage Program
- Respiratory Protection Program
- Employee Exposure Monitoring Program
- Hand and Portable Power Tool Safety Program
- Hearing Conservation Program
- Back Injury Prevention Program
- Hazard Communication Program
- Heat and Cold Stress Monitoring and Control Program
- Pressure Vessel and Pipeline Safety Program
- Hazardous Waste Program
- Hot Work Safety Program
- Permit-Required Confined Space Entry Program

The Application for Certification (AFC) includes adequate outlines of each of the above programs (CECP 2007a, § 5.16.4.3.1). Prior to the start of construction of CECP, detailed programs and plans would be provided to the California Energy Commission Compliance Project Manager (CPM) and to the CFD pursuant to the Condition of Certification **WORKER SAFETY-1**.

Operations and Maintenance Safety and Health Program

Prior to the start of operations at CECP, the Operations and Maintenance Safety and Health Program would be prepared. This operational safety program would include the following programs and plans:

- Injury and Illness Prevention Program (8 Cal Code Regs. § 3203)
- Fire Protection and Prevention Program (8 Cal Code Regs. § 3221)
- Personal Protective Equipment Program (8 Cal Code Regs. §§ 3401 to 3411)
- Emergency Action Plan (8 Cal Code Regs. § 3220)

In addition, the requirements under General Industry Safety Orders (8 Cal Code Regs. §§ 3200 to 6184), Electrical Safety Orders (8 Cal Code Regs. §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 Cal Code Regs. §§ 450 to 544) would be applicable to the project. Written safety programs for CECP, which the applicant would develop, would ensure compliance with the above-mentioned requirements.

The AFC includes adequate outlines of the Injury and Illness Prevention Program, Emergency Action Plan, Fire Prevention Program, and Personal Protective Equipment

Program (CECP 2007a, § 5.16.4.3.2). Prior to operation of CECP, all detailed programs and plans would be provided to the CPM and CFD pursuant to Condition of Certification **WORKER SAFETY-2**.

Safety and Health Program Elements

As mentioned above, the applicant provided the proposed outlines for both a Construction Safety and Health Program and an Operations Safety and Health Program. The measures in these plans are derived from applicable sections of state and federal law. Both safety and health programs would be comprised of six more specific programs and would require major items detailed in the following paragraphs.

Injury and Illness Prevention Program

The IIPP would include the following components as presented in the AFC (CECP 2007a, § 5.16.4.3.2):

- identity of person(s) with authority and responsibility for implementing the program;
- safety and health policy of the plan;
- definition of work rules and safe work practices for construction activities;
- system for ensuring that employees comply with safe and healthy work practices;
- system for facilitating employer-employee communications;
- procedures for identifying and evaluating workplace hazards and developing necessary program(s);
- methods for correcting unhealthy/unsafe conditions in a timely manner;
- safety procedures; and
- training and instruction.

Fire Prevention Plan

California Code of Regulations requires an Operations Fire Prevention Plan (8 Cal Code Regs. § 3221). The AFC outlines a proposed Fire Prevention Plan which is acceptable to staff (CECP 2007a, § 5.16.4.3.2). The plan would accomplish the following:

- determine general program requirements;
- determine fire hazard inventory, including ignition sources and mitigation;
- develop good housekeeping practices and proper materials storage;
- establish employee alarm and/or communication system(s);
- provide portable fire extinguishers at appropriate site locations;
- locate fixed fire-fighting equipment in suitable areas;
- specify fire control requirements and procedures;
- establish proper flammable and combustible liquid storage facilities;
- identify the location and use of flammable and combustible liquids;

- provide proper dispensing and determine disposal requirements for flammable liquids;
- establish and determine training and instruction requirements and programs; and
- identify personnel to contact for information on plan contents.

Staff proposes that the applicant submit a final Fire Prevention Plan to the CPM for review and approval and to the CFD for review and comment to satisfy proposed Conditions of Certification **WORKER SAFETY-1** and **WORKER SAFETY-2**.

Personal Protective Equipment Program

California regulations require Personal Protective Equipment (PPE) and first aid supplies whenever hazards are present that, due to process, environment, chemicals or mechanical irritants, can cause injury or impair bodily function as a result of absorption, inhalation, or physical contact (8 Cal Code Regs. §§ 3380 to 3400). The CECP operational environment would require PPE.

All safety equipment must meet National Institute of Safety and Health (NIOSH) or American National Standards Institute (ANSI) standards and would carry markings, numbers, or certificates of approval. Respirators must meet NIOSH and Cal/OSHA standards. Each employee must be provided with the following information pertaining to the protective clothing and equipment:

- proper use, maintenance, and storage;
- when to use the protective clothing and equipment;
- benefits and limitations; and
- when and how to replace the protective clothing and equipment.

The PPE Program ensures that employers comply with the applicable requirements for PPE and provides employees with the information and training necessary to protect them from potential workplace hazards.

Emergency Action Plan

California regulations require an Emergency Action Plan (8 Cal Code Regs. § 3220). The AFC contains a satisfactory outline for an emergency action plan (CECP 2007a, § 5.16.4.3.2).

The outline lists plans to accomplish the following:

- establish emergency escape procedures and emergency escape route for the facility;
- determine procedures to be followed by employees who remain to operate critical plant operations before they evacuate;
- provide procedures to account for all employees and visitors after emergency evacuation of the plant has been completed;
- specify rescue and medical duties for assigned employees;

- identify fire and emergency reporting procedures to regulatory agencies;
- develop alarm and communication system for the facility;
- establish a list of personnel to contact for information on the plan contents;
- provide emergency response procedures for ammonia release; and
- determine and establish training and instruction requirements and programs.

Written Safety Program

In addition to the specific plans listed above, additional LORS called *safe work practices* apply to the project. Both the Construction and the Operations Safety Programs would address safe work practices under a variety of programs. The components of these programs include, but are not limited to, the programs found under the heading "Construction Safety and Health Program" in this **Worker Safety and Fire Protection** section.

Safety Training Programs

Employees would be trained in the safe work practices described in the above-referenced safety programs.

Additional Mitigation Measures

Protecting construction workers from injury and disease is among the greatest challenges in occupational safety and health. The following facts are reported by the National Institute for Occupational Safety and Health (NIOSH):

- More than 7 million persons work in the construction industry, representing 6 percent of the labor force. Approximately 1.5 million of these workers are self-employed.
- Of approximately 600,000 construction companies, 90 percent employ fewer than 20 workers. Few have formal safety and health programs.
- From 1980 to 1993, an average of 1,079 construction workers were killed on the job each year—more fatal injuries than in any other industry.
- Falls caused 3,859 construction worker fatalities (25.6 percent) between 1980 and 1993.
- Construction injuries account for 15 percent of workers' compensation costs.
- Assuring safety and health in construction is complex, involving short-term work sites, changing hazards, and multiple operations and crews working in close proximity.
- In 1990, Congress directed NIOSH to undertake research and training to reduce diseases and injuries among construction workers in the United States. Under this mandate, NIOSH funds both intramural and extramural research projects.

The hazards associated with the construction industry are thus well documented. These hazards increase in complexity in the multi-employer worksites typical of large, complex, industrial-type projects such as the construction of gas-fired power plants. In order to reduce and/or eliminate these hazards, it has become standard industry practice to hire

a Construction Safety Supervisor to ensure a safe and healthful environment for all personnel. That this standard practice has reduced and/or eliminated hazards has been evident in the audits staff recently conducted of power plants under construction. The federal Occupational Safety and Health Administration (OSHA) has also entered into strategic alliances with several professional and trade organizations to promote and recognize safety professionals trained as Construction Safety Supervisors, Construction Health and Safety Officers, and other professional designations. The goal of these partnerships is to encourage construction subcontractors in four areas:

- to improve their safety and health performance;
- to assist them in striving for the elimination of the four hazards (falls, electrical, caught in/between and struck-by hazards), which account for the majority of fatalities and injuries in this industry and have been the focus of targeted OSHA inspections;
- to prevent serious accidents in the construction industry through implementation of enhanced safety and health programs and increased employee training; and
- to recognize those subcontractors with exemplary safety and health programs.

To date, there are no OSHA or Cal/OSHA requirements that an employer hire or provide for a Construction Safety Officer. OSHA and Cal/OSHA regulations do, however, require that safety be provided by an employer and the term *Competent Person* is used in many OSHA and Cal/OSHA standards, documents, and directives. A Competent Person is usually defined by OSHA as an individual who, by way of training and/or experience, is knowledgeable of standards, is capable of identifying workplace hazards relating to the specific operations, is designated by the employer, and has authority to take appropriate action. Therefore, in order to meet the intent of the OSHA standard to provide for a safe workplace during power plant construction, staff proposes Condition of Certification **WORKER SAFETY-3,** which would require the applicant/project owner to designate and provide for a power plant site Construction Safety Supervisor.

As discussed above, the hazards associated with the construction industry are well documented. These hazards increase in complexity in the multi-employer worksites typical of large, complex, industrial-type projects such as the construction of gas-fired power plants.

Accidents, fires, and a worker death have occurred at Energy Commission-certified power plants in the recent past due to the failure to recognize and control safety hazards and the inability to adequately supervise compliance with occupational safety and health regulations. Safety problems have been documented by Energy Commission staff in safety audits conducted in 2005 at several power plants under construction. The findings of the audit staff include, but are not limited to, such safety oversights as:

- lack of posted confined space warning placards/signs;
- confusing and/or inadequate electrical and machinery lockout/tagout permitting and procedures;

- confusing and/or inappropriate procedures for handing over lockout/tagout and confined space permits from the construction team to commissioning team and then to operations;
- dangerous placement of hydraulic elevated platforms under each other;
- inappropriate placement of fire extinguishers near hotwork;
- dangerous placement of numerous power cords in standing water on the site, thus increasing the risk of electrocution;
- construction of an unsafe aqueous ammonia unloading pad;
- inappropriate and unsecure placement of above-ground natural gas pipelines inside the facility but too close to the perimeter fence; and
- lack of adequate employee- or contractor-written training programs addressing proper procedures to follow in the event of finding suspicious packages or objects either on or off site.

In order to reduce and/or eliminate these hazards, it is necessary for the Energy Commission to have a professional Safety Monitor on site to track compliance with Cal/OSHA regulations and periodically audit safety compliance during construction, commissioning, and the hand-over to operational status. These requirements are outlined in Condition of Certification **WORKER SAFETY-4**. A Safety Monitor, hired by the project owner, yet reporting to the Chief Building Official (CBO) and CPM, will serve as an “extra set of eyes” to ensure that safety procedures and practices are fully implemented at all power plants certified by the Energy Commission. During the audits conducted by staff, most site safety professionals welcomed the audit team and actively engaged it in questions about the team’s findings and recommendations. These safety professionals recognized that safety requires continuous vigilance and that the presence of an independent audit team provided a fresh perspective of the site.

Fire Hazards

During construction and operation of the proposed CECP project, there is the potential for both small fires and major structural fires. Electrical sparks, combustion of fuel oil, natural gas, hydraulic fluid, mineral oil, insulating fluid at the power plant switchyard or flammable liquids, explosions, and over-heated equipment, may cause small fires. Major structural fires in areas without automatic fire detection and suppression systems are unlikely to develop at power plants. Fires and explosions of natural gas or other flammable gasses or liquids are rare. Compliance with all LORS would be adequate to assure protection from all fire hazards.

Staff reviewed the information provided in the AFC and spoke to representatives of the Carlsbad Fire Department to determine if available fire protection services and equipment would adequately protect workers and to determine the project’s impact on fire protection services in the area. The project will rely on both on-site fire protection systems and local fire protection services. The on-site fire protection system provides the first line of defense for small fires. In the event of a major fire, fire support services, including trained firefighters and equipment for a sustained response, would be provided by the CFD (CFD 2008).

Construction

During construction, portable fire extinguishers would be placed throughout the site at appropriate intervals and periodically maintained, and safety procedures and training would be implemented according to the guidelines of the Construction Fire Protection and Prevention Program. In addition, the CECP proposed site is within the tank farm area of the Encina Power Station, which has an existing hydrant system that could provide extra protection during construction (CECP 2007a, § 2.2.12).

Operation

The information in the AFC indicates that the project intends to meet the fire protection and suppression requirements of the 2007 California Fire Code, all applicable recommended NFPA standards (including Standard 850 addressing fire protection at electric generating plants), and all Cal/OSHA requirements. Fire suppression elements in the proposed plant would include both fixed and portable fire extinguishing systems. The fire protection system would be comprised of the existing hydrant system and a new R2C2 system installed for CECP structures. The fire water would be potable city water supplied by the fire protection tank with water pressure maintained by a jockey pump, an electric pump, and a diesel-driven pump (CECP 2007a, § 2.2.12).

Emergency access to the site will be via two points: one on the south via Cannon Road to Avenida Encinas to the project site and the other from the west via Carlsbad Boulevard and through the Encina Power Station. Access to the below-grade “bowl” will also be via two points, one on the south and one on the north. Revised Figure 2.2-1 (SR 2008h) shows these access points and depicts the width of the ramps leading down into the bowl and set-back space of the structures from the sides of the bowl. All distances shown on this figure are consistent with the requirements of the fire codes for a “fire lane” and thus will allow fire trucks and other emergency vehicle access to the actual power plant site in the bowl. California Fire Code (CFC) section 503.1.1 and NFPA 1 Uniform Fire Code section 18.2.2.3.1 both require that an access road extend to within 150 feet of all portions of a facility and CFC section 503.2.1 and NFPA 1 section18.2.2.5.1.1 both require that the access road have an unobstructed width of at least 20 feet. Staff review of the plot plans for the project and in conversations with the applicant shows that these minimum requirements will be met and exceeded. The plot-plans show that both ramps and the road around the power plant at the bottom of the “bowl” will be at least 30 feet wide at all places. Therefore, all emergency vehicles and especially fire trucks will have ample space to be able to respond to an emergency at any location within the bowl.

Nevertheless, while these codes and requirements are known to the applicant as evidenced by their listing in the AFC, in order to ensure that the project owner builds the facility precisely to code, staff proposes an additional Condition of Certification **WORKER SAFETY-6** that would require the project owner to construct the facility with the fire lanes and ramp-widths as described in Revised Figure 2.2-1. The widths of the fire lanes will be no less that 30 feet and the ramps would have a grade no greater than 10%. Should any change or revision to these widths be requested for any reason by the project owner, the project owner would be required to submit those changes to the CPM for review and approval and to the CFD for review and comment.

Fire hydrants would be installed per NFPA requirements. A fixed water mist system would be installed in areas of risk (including the ammonia storage area, fire pumps, and turbines), and a fixed sprinkler system would be installed in the turbine lube oil system. A carbon dioxide or dry chemical fire protection system would be provided for the combustion turbine generators and accessory equipment (CECP 2007a, § 2.2.12).

The fire protection system would have fire detection sensors and monitoring equipment that would trigger alarms and automatically actuate the suppression systems. In addition to the fixed fire protection system, appropriate class of service portable extinguishers and fire hydrants/hose stations would be located throughout the facility at code-approved intervals (CECP 2007a, § 2.3.1.1.2). These systems are standard requirements by the NFPA, and the UFC and staff has determined that they will ensure adequate fire protection.

The applicant would be required by Conditions of Certification **WORKER SAFETY-1** and**-2** to provide the final Fire Protection and Prevention Program to staff and to the CFD prior to construction and operation of the project to confirm the adequacy of the proposed fire protection measures.

Emergency Medical Services Response

Staff conducted a statewide survey to determine the frequency of Emergency Medical Services (EMS) response and off-site fire-fighter response for natural gas-fired power plants in California. The purpose of the analysis was to determine what impact, if any, power plants may have on local emergency services. Staff has concluded that incidents at power plants that require fire or EMS response are infrequent and represent an insignificant impact on the local fire departments, except for rare instances where a rural fire department has mostly volunteer fire-fighting staff. However, staff has determined that the potential for both work-related and non-work-related heart attacks exists at power plants. In fact, staff's research on the frequency of EMS response to gas-fired power plants shows that many of the responses for cardiac emergencies involved non-work-related incidences, including those involving visitors. The need for prompt response within a few minutes is well documented in the medical literature. Staff believes that the quickest medical intervention can only be achieved with the use of an on-site automatic external defibrillator (AED); the response from an off-site provider would take longer regardless of the provider location. This fact is also well documented and serves as the basis for many private and public locations (e.g., airports, factories, government buildings) maintaining on-site cardiac defibrillation devices. Therefore, staff concludes that, with the advent of modern cost-effective cardiac defibrillation devices, it is proper in a power plant environment to maintain such a device on site in order to treat cardiac arrythmias resulting from industrial accidents or other non-work related causes.

Staff proposes Condition of Certification **WORKER SAFETY-5,** which would require that this portable AED be located on site, that all power plant employees on site during operations be trained in its use, and that a representative number of workers on site during construction and commissioning also be trained in its use.

WIDENING OF INTERSTATE-5 AND MITIGATION

Staff has also considered a separate future project that is several years off—the widening of Interstate Highway 5 through Carlsbad-- but has the potential to affect the setting for emergency response by the CFD. The I-5 freeway is proposed to be widened and may thus encroach on the present "buffer" that exists between the highway and the faciltiy fenceline. This "buffer" consists of trees, bushes, and a raised area above the I-5 grade. According to the California Department of Transportation (Caltrans 2009), all four configurations of the I-5 widening currently under consideration will result in the removal of some if not all the current vegetation and raised area that serve as the "buffer". The present "buffer" would serve many safety functions if the CECP is certified, built, and operated, including protection of critical engergy infrastructure and workers from errant vehicles leaving I-5, increasing security of the power plant by blocking access and line-of-sight viewing, and enabling fire-fighting equipment to use the existing upper ("ring") road that is above the power plant site as a viewing and fire-fighting platform.

Staff has extensively reviewed and evaluated the potential impact of the propsoed I-5 widening on safety at the proposed CECP. On June 11, 2009, staff met with Caltrans staff and the applicant at the CECP site to view the survey markers made by Caltrans engineers the day before and to discuss the precise distance of encroachment onto the CECP site should the I-5 widening project be built eight to ten years from now.

The two areas where the Caltrans I-5 widening come the closest to the power plant are:

1. Directly east of the water treatment trailer parking area (which is east of Structure 43-water treatment pumps on AFC Revised Fig. 2.2-1, which is attached to this FSA section in Appendix A as Figure 1). At this location, the Caltrans I-5 **8+4 with Barrier configuration** will extend the Caltrans ROW west to **26'** from the western edge of the existing upper ring road (8' from eastern edge; see wooden stake with red flag in Photo 023 attached to this FSA section in Appendix A). There would be a total of **105 feet** from the Caltrans ROW to the nearest structure, a water treatment trailer. If the current 45° slope going down inside the "bowl" (se Photo 002) is replaced with a vertical retaining wall that is located west of the existing slope toe and a 30' fire lane is maintained, the CECP would have a total of **75 feet** of flat area for visual-blocking vegetation and a protective barrier + security fence. That would be the maximum distance from the Caltrans ROW available at this location.
2. Directly east of the SCR skid (Structure 18 on AFC Revised Fig. 2.2-1 which is attached to this FSA section in Appendix A as Figure 1), the **8+4 with Barrier configuration** will extend the Caltrans ROW west to **18 feet** from the **western** edge of the existing upper ring road (essentially up to the existing eastern edge of the ring road; see Photos 009 and 017). There would be a total of **120'** from the Caltrans ROW to the nearest structure, the SRC skid. If the current 45° slope going down inside the site bowl is replaced with a vertical retaining wall located west of the current "toe" and a 30' fire lane is maintained, CECP would have a total of **90'** of flat area for visual-blocking vegetation and a protective barrier + security fence. That would be the maximum distance from the Caltrans ROW available at this location.

If the I-5 **10+4 with Barrier configuration** is chosen by Caltrans, the CECP at the closest point would have **45 feet** available for visual-blocking vegetation and a protective barrier + security fence if a retaining wall is used.

After review of this matter with the assistance of Caltrans, staff believes there is ample room under both the 8+4 and 10+4 configurations (the widest configurations Caltrans is considering) for the placement of a dirt berm west of the future Caltrans ROW. This berm can serve as a place for visual-blocking vegetation and serve as a protective barrier room for a security fence. Staff also believes that the I-5 encroachment will still leave room for a perimeter fire access road at the bottom of the bowl where the power plant will be located. Therefore, staff concludes that the widening of I-5 will not imapct on safety or emergency response access to the proposed CECP site.

Because protection of the nation's energy infrastructure as well as workers is of paramount importance, staff thus proposes Condition of Certification **WORKER SAFETY-7**. This condition would require the project owner to place a barrier (earth or other materials) along the entire eastern property line shared by the CECP and Interstate-5 and that it be of sufficent strength and height so as to prevent a runaway car or semi-trailer truck from piercing the barrier and going over the edge and down into the power plant site. This barrier shall also serve to prevent line-of-sight viewing of the power plant site from the shoulder of I-5. In designing the barrier, the project owner will be required to consult with Caltrans and then submit a final plan to the Energy Commission Compliance Project Manager for review and approval. The project owner will be free to negotiate cost-sharing of this barrier with Caltrans and will be required to submit the cost-sharing contract with Caltrans to the CPM for review and approval. Staff believes that this barrier will serve the dual purpose of protecting safety and security. The loss of the existing above-grade "ring" road is offset by the required below-grade perimeter road for emergency response vehicles that will be built to code specifications as per **WORKER SAFETY-6**.

COASTAL RAIL TRAIL

Another fire access issue involves the various proposed routes for a Coastal Rail Trail. Staff believes that a Rail Trail on the eastern side of the railroad ROW, an option under consideration, raises several security, safety, and fire access problems. Staff discusses the security and safety concerns in the **HAZARDOUS MATERIALS MANAGEMENT** section of the FSA and fire access issues here.

As seen in Appendix D **photo 063**, the current rail corridor is single-track and sunken below existing grade as it goes by the power plant site. Staff understands that one option for the LOSSAN Rail Corridor would have two tracks within this area and sink the new side-by-side tracks a bit further below grade. The most current plot-plan for the CECP site (Figure 1) shows a dirt road that is just east of the western fenceline. A review of **photos 059 and 060** shows this dirt road is very wide, runs the length of the CECP project site, and starts on the south end of the site (the SW corner of the site) where an access gate is located. This access gate and dirt road will serve as the construction entrance for heavy equipment and for access to the north side of the site for this heavy equipment. The applicant proposes to pave this road or at least make a sturdier route with gravel. After construction, the gate at the SW corner will serve as an

emergency vehicle access point that will be required by proposed Condition of Certification **WORKER SAFETY-6**. This road will also serve as faster means of accessing the northern end of the site for emergency response vehicles during Commissioning and Operations and the placement of dirt spoils to form a berm along most of it will not block its use. Furthermore, the City has a sewer under this road now and maintains a sewer easement. Therefore, in order to preserve this road on the western side of the CECP site for emergency response access, staff proposes Condition of Certification **WORKER SAFETY-9** which will require the continued presence of this access road and prohibit the placement of a coastal rail trail at this location. The proposed Condition is consistent with those proposed in the **LAND USE** and **HAZARDOUS MATERIALS MANAGEMENT** sections of this FSA.

OPERATION OF THE POWER PLANT

When staff learned that the applicant proposes to operate the CECP from a remote control room on the EPS site, staff identified the following issues as being relevant to remote operation:

- The proposed use, location, and redundancy of operational warning sensors, fire sensors, ammonia sensors, pipeline sensors, valve activation, fire suppression systems, and CCTV locations.
- The response times for personnel to reach the power plant from the control room.
- The staffing level of each shift and whether they are dedicated to running the CECP or will have duties involving the EPS.
- The frequency of routine visual inspections and the time spent on the CECP site.
- The frequency of on-site security surveillance of the CECP site by security guards.
- The worker training program for a remote operation.
- How workers will access the CECP site in an emergency given the frequency of long freight trains blocking access to the site directly from the EPS site for a period of time.
- The location and response times for all manually activated valves (e.g., the main gas pipeline shut-off valve) should remote activation fail.
- Emergency shut-down procedures should access to the site be blocked or delayed due to an accident (vehicle, train), high winds knocking down power lines, etc. when a shut-down is warranted.

The Energy Commission does have experience with certified power plants that are run remotely. These include the three GWF power plants at Tracy, Henrietta, and Hanford. Henrietta and Tracy are simple-cycle and are usually started-up remotely but at least one worker is always dispatched to the site and stays on the site until the units are shut-down (or is relieved at a shift-change). These are peaker power plants, are run infrequently, and have always had at least one worker present when operating. However, they are being converted to combined-cycle power plants and thus will no longer be operated remotely and will always have multiple workers present when operating. The Hanford peaker is a bit different and is run from the existing Hanford LLP coke-fueled power plant on the same site. Hanford peaker is also being converted to a combined-cycle power plant and it can either be operated from its own control room or from the existing Hanford LLP plant. The differences between the Hanford-Hanford LLP sites and the CECP-EPS sites are significant. The distance from the control room at the Hanford LLP site and the Hanford combine cycle site is less than 500 feet. There are no

railroad tracks separating them and there is no “bowl” to traverse into. At the CECP site, the shortest distance from a possible location for a control room at the EPS to the CECP site in the bowl is ~1085 feet but could be longer. And, since this would be a combined-cycle power plant, workers should always be on-site.

After identifying and considering the above issues, staff’s major concern about the absence of a permanent worker-force on the site during operations is that a small problem (e.g., ammonia piping leak, small fire, small gas leak) would turn into a big problem because it wasn’t detected soon enough. Therefore, staff believes that a combined-cycle power plant cannot be operated safely and effectively from a remote location and thus proposes an additional Condition of Certification **WORKER SAFETY-8** that would require the project owner to ensure that at a minimum, two workers are always present on the CEPC site (in the “bowl”) when the power plant is operating.

CUMULATIVE IMPACTS AND MITIGATION

Staff reviewed the potential for the construction and operation of the CECP project combined with existing industrial facilities and expected new facilities, including the existing adjacent Encina Power Station, to result in impacts on the fire and emergency service capabilities of the CFD and initially found that there was a potential for cumulative impacts to occur. The CFD had indicated that although it is currently able to respond to all incidents in its jurisdiction, resources are stretched thin and the proposed CECP may add a burden to the department. The CFD as a whole has six fire stations spread over 48 square miles. In CFD’s opinion, this low station density and the fact that the CFD has not expanded while the city of Carlsbad has grown, contribute to the CFD’s concern regarding future response capabilities. A particular concern of the CFD is the likelihood of a seismic event in the region, which would require that all of its resources be used. In CFD’s opinion, if such a regional event were to occur, the proposed CECP would impact the Carlsbad Fire Department. According to the CFD, any new project in its jurisdiction, especially a facility that stores and uses hazardous and flammable materials such as the CECP, is likely to impact the CFD (CFD 2008).

Given the CFD’s opinion that its ability to respond during a major crisis might be impacted by the operation of this power plant, staff conducted a thorough review of this matter that included evaluating all comments and information provided by the applicant and the CFD and by reviewing the past history of emergency responses at the Encina Power Station.

As a result of staff’s query to the applicant about past emergency response to the EPS, the following information was received:

Fire Response: Since NRG acquired EPS in 1999, there have been no fires of any type at EPS and CFD has not been called or had to respond to any fires at EPS. NRG does not have information regarding fires or CFD response to fire at EPS prior to NRG's acquisition of the site in 1999.

HazMat Spill Response: Since NRG acquired EPS in 1999, there have not been hazmat spills of type of spill quantity that required CFD response or San Diego County Department of Environmental Health response. CFD relies on the San Diego County

Department of Environmental Health for hazardous materials response within the City. NRG has a contract with NRC Environmental Services to provide hazardous materials response if such response is needed at EPS.

Accident Response (rescue operation; trench cave-in; confined space; etc): Since NRG acquired EPS in 1999, there have been no rescue operations at EPS. NRG has NRC Environmental Services act as attendant during all confined space work at EPS.

EMS Response (heart attack; heat stroke; etc): Since NRG acquired EPS in 1999, there have been EMS responses by CFD to EPS on average of one response every 2 to 3 years. With the exception of one EMS response several years ago where an on-site contractor experienced difficulty breathing, the EMS calls have been false alarms, or determined to not have required EMS response.

Based upon the applicant's Fire Needs Assessment (SR 2008t, which was produced by an independent contractor to the applicant, and remains unrefuted by any another Fire Needs Assessment), staff's preliminary risk assessment, the history of emergency response at the EPS, staff's experience with power plants around the state, and staff's experience with a similar-sited power plant where access is restricted due to a below-grade location, staff concludes that while it is possible that during a major earthquake (or other major event) response to the power plant could impact on the Carlsbad Fire Department, the probability of that happening is less than significant. Therefore, this project would not have a significant incremental or cumulative impact on the department's ability to respond to a fire or other emergency and no mitigation is required.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Please see Appendix B for responses to comments.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Staff concludes that construction and operation of the CECP project would be in compliance with all applicable laws, ordinances, regulations, and standards (LORS) regarding long-term and short-term project impacts in the area of worker safety and fire protection.

CONCLUSIONS

Staff concludes that if the applicant for the proposed CECP project provides a Project Construction Safety and Health Program and a Project Operations and Maintenance Safety and Health Program as required by Conditions of Certification **WORKER SAFETY-1**, and **-2** and fulfils the requirements of Condition of Certification **WORKER SAFETY-3** through**-9**, the project would incorporate sufficient measures to ensure adequate levels of industrial safety and comply with applicable LORS. Staff also

concludes that the operation of this power plant would not present a significant cumulative impact on the local fire department and therefore mitigation is not required.

PROPOSED CONDITIONS OF CERTIFICATION

WORKER SAFETY-1 The project owner shall submit to the Compliance Project Manager (CPM) a copy of the Project Construction Safety and Health Program containing the following:

- a Construction Personal Protective Equipment Program;
- a Construction Exposure Monitoring Program;
- a Construction Injury and Illness Prevention Program;
- a Construction Emergency Action Plan; and
- a Construction Fire Prevention Plan.

The Personal Protective Equipment Program, the Exposure Monitoring Program, and the Injury and Illness Prevention Program shall be submitted to the CPM for review and approval concerning compliance of the program with all applicable safety orders. The Construction Emergency Action Plan and the Fire Prevention Plan shall be submitted to the Carlsbad Fire Department for review and comment prior to submittal to the CPM for approval.

Verification: At least 30 days prior to the start of construction, the project owner shall submit to the CPM for review and approval a copy of the Project Construction Safety and Health Program. The project owner shall provide a copy of a letter to the CPM from the Carlsbad Fire Department stating the fire department's comments on the Construction Fire Prevention Plan and Emergency Action Plan.

WORKER SAFETY-2 The project owner shall submit to the CPM a copy of the Project Operations and Maintenance Safety and Health Program containing the following:

- an Operation Injury and Illness Prevention Plan;
- an Emergency Action Plan;
- Hazardous Materials Management Program;
- Fire Prevention Plan (8 Cal Code Regs. § 3221); and
- Personal Protective Equipment Program (8 Cal Code Regs, §§ 3401—3411).

The Operation Injury and Illness Prevention Plan, Emergency Action Plan, and Personal Protective Equipment Program shall be submitted to the CPM for review and comment concerning compliance of the programs with all applicable safety orders. The Fire Prevention Plan and the Emergency Action Plan shall also be submitted to the Carlsbad Fire Department for review and comment.

Verification: At least 30 days prior to the start of first-fire or commissioning, the project owner shall submit to the CPM for approval a copy of the Project Operations and Maintenance Safety and Health Program. The project owner shall provide a copy of a letter to the CPM from the Carlsbad Fire Department stating the fire department's comments on the Operations Fire Prevention Plan and Emergency Action Plan.

WORKER SAFETY-3 The project owner shall provide a site Construction Safety Supervisor (CSS) who, by way of training and/or experience, is knowledgeable of power plant construction activities and relevant laws, ordinances, regulations, and standards; is capable of identifying workplace hazards relating to the construction activities; and has authority to take appropriate action to assure compliance and mitigate hazards. The CSS shall:

- have overall authority for coordination and implementation of all occupational safety and health practices, policies, and programs;
- assure that the safety program for the project complies with Cal/OSHA and federal regulations related to power plant projects;
- assure that all construction and commissioning workers and supervisors receive adequate safety training;
- complete accident and safety-related incident investigations and emergency response reports for injuries and inform the CPM of safety-related incidents; and
- assure that all the plans identified in Conditions of Certification Worker Safety-1 and -2 are implemented.

Verification: At least 60 days prior to the start of site mobilization, the project owner shall submit to the CPM the name and contact information for the Construction Safety Supervisor (CSS). The contact information of any replacement CSS shall be submitted to the CPM within one business day.

The CSS shall submit in the Monthly Compliance Report a monthly safety inspection report to include:

- record of all employees trained for that month (all records shall be kept on site for the duration of the project);
- summary report of safety management actions and safety-related incidents that occurred during the month;
- report of any continuing or unresolved situations and incidents that may pose danger to life or health; and
- report of accidents and injuries that occurred during the month.

WORKER SAFETY-4 The project owner shall make payments to the Chief Building Official (CBO) for the services of a Safety Monitor based upon a reasonable fee schedule to be negotiated between the project owner and the CBO. Those services shall be in addition to other work performed by the CBO. The Safety Monitor shall be selected by and report directly to the CBO and will be

responsible for verifying that the Construction Safety Supervisor, as required in Condition of Certification Worker Safety-3, and for implementing all appropriate Cal/OSHA and Energy Commission safety requirements. The Safety Monitor shall conduct on-site (including linear facilities) safety inspections at intervals necessary to fulfill those responsibilities.

Verification: At least 60 days prior to the start of construction, the project owner shall provide proof of its agreement to fund the Safety Monitor services to the CPM for review and approval.

WORKER SAFETY-5 The project owner shall ensure that a portable automatic external defibrillator (AED) is located on site during construction and operations and shall implement a program to ensure that workers are properly trained in its use and that the equipment is properly maintained and functioning at all times. During construction and commissioning, the following persons shall be trained in its use and shall be on site whenever the workers that they supervise are on site: the Construction Project Manager or delegate, the Construction Safety Supervisor or delegate, and all shift foremen. During operations, all power plant employees shall be trained in its use. The training program shall be submitted to the CPM for review and approval.

Verification: At least 60 days prior to the start of site mobilization, the project owner shall submit to the CPM proof that a portable automatic external defibrillator (AED) exists on site and a copy of the training and maintenance program for review and approval.

WORKER SAFETY-6 The project owner shall ensure that the below-grade site fire lanes,, access points, and ramps (with no more than a 10% grade) are constructed as per the dimensions shown in Revised Figure 2.2-1 and that at least two access points through the site perimeter and into the below-grade power plant site are available to the CFD and other emergency response providers. The final blueprints for the site shall be submitted at least 30 days prior to the start of site mobilization to the Carlsbad Fire Department for review and comment and to the CPM for review and approval. A copy of the transmittal letter to the Carlsbad Fire Department shall also be sent to the CPM. Any requested changes in the fire lanes, ramps, and access points shall be made is writing to the CPM and the CBO for review and approval after obtaining comments from the CFD.

Verification: At least 60 days prior to the start of site mobilization, the project owner shall submit a copy of the final site blueprints to the Carlsbad Fire Department for review and comments and to the CPM for review and approval. The project owner shall also submit to the CPM a copy of the transmittal letter to the CFD.

WORKER SAFETY-7 The project owner shall place a barrier of sufficient strength and height at the eastern fence line of the project at the widened Interstate-5 Right of Way so as to prevent a runaway car or semi-trailer truck from piercing the barrier and going over the edge and down into the power plant site. This barrier shall also serve to prevent line-of-sight viewing of the power plant site from the shoulder of I-5. In designing this barrier, the project owner shall consult with Caltrans and then submit a final plan to the CPM for review and

approval. The project owner may also negotiate cost-sharing of this barrier with Caltrans and if the project owner chooses to do so, the cost-sharing contract with Caltrans shall be submitted to the CPM for review and approval.

Verification: At least 60 days prior to the start of site mobilization, the project owner shall submit a copy of the final plans for the barrier and any cost-sharing contract to the CPM for review and approval.

WORKER SAFETY-8 The project owner shall ensure that not less than two workers - two technical workers or one technical and one security staff - will be present on the site (the "bowl") at all times whenever the CECP is operating. The project owner shall prepare a plan describing the work force that shall be present on the power plant site (the "bowl"), their shifts, their duties, their training, the method(s) of real-time continuous communication with the control room they will have available, their enclosed stations (e.g., portable office building), and facilities for personal hygiene on the site, to the CPM for review and approval.

Verification: At least 60 days prior to the start of commercial operations, the project owner shall submit a copy of the staffing plan to the CPM for review and approval.

WORKER SAFETY-9 The project owner shall maintain the current dirt access road located on the western perimeter fenceline in a sufficient state so as to serve as an emergency response road. In no event shall the project owner grant or dedicate an easement for the Coastal Rail Trail east of the Rail Corridor on the CECP site.

Verification: At least 60 days prior to the start of site mobilization, the project owner shall submit to the CPM for review and approval a copy of the final plans for maintaining this access road.

REFERENCES

California Fire Code 2007. Published by the International Fire Code Institute comprised of the International Conference of Building Officials, the Western Fire Chiefs Association, and the California Building Standards Commission. Whittier, Ca.

Caltrans 2009a – California Dept. of Trans/J. Kosup (tn: 50098) Caltrans Comments on the Preliminary Staff Assessment. 02/05/2009

CECP 2007a – California Energy Center Project/T. Hemig (tn: 42299). Application for Certification for the Carlsbad Energy Center Project. 09/11/2007. Rec'd 09/11/2007.

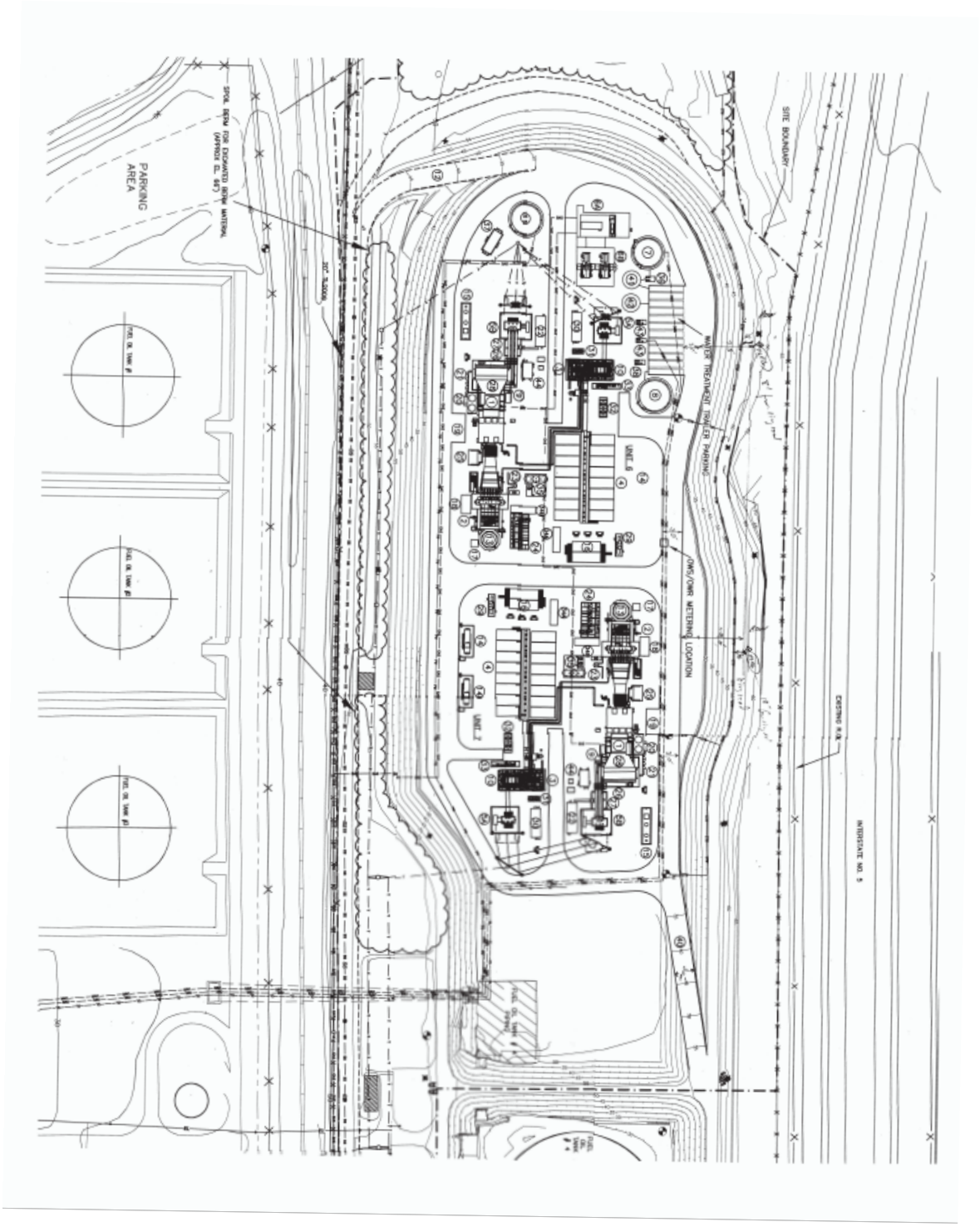
CFD 2008 – Carlsbad Fire Department. Record of conversation with Fire Marshal James Weigand, May 28, 2008.

NFPA 1 Uniform Fire Code 2003, Vol. 1. Published by the National Fire Protection Association with incorporated provisions of the Western Fire Chiefs Association Uniform Fire Code.

SR 2008t – Stoel Rives/K Hellwig (tn: 49006). Fire Risk & Emergency Response Assessment Report. 11/17/2008

WORKER SAFETY/FIRE PROTECTION APPENDIX A

Figure 1



WORKER SAFETY/FIRE PROTECTION APPENDIX B

Response to Agency and Public Comments

POWER OF VISION Comments

POV2009a – Power of Vision/Julie Backer (tn: 49934). Comments on Preliminary Staff Assessment ("Safety" Comments). 1/30/2009

Comment: CECP cannot be adequately protected in case of a fire or wild fires. The site is difficult to access for emergency responders. The lowered elevation of CECP will make it difficult for fire personnel to access. When I-5 is widened there will be not room for maneuvering large fire trucks.

Response: Staff has made a considerable effort to review this matter and has reviewed all materials and opinions supplied to date. As the above analysis demonstrates, there is ample room for access now and in the future should I-5 be widened. Staff has experience in siting and in monitoring compliance during the construction and operation of a power plant located in a similar below-grade and constricted location, the Palomar Power Plant in nearby Escondido. This power plant site has high walls located on three sides and is open and at grade only to the south. The ability to provide emergency response was not a concern of the Escondido Fire Department. In fact, almost all urban power plants are located at constricted locations and yet emergency access is ensured by LORS that require minimum widths of fire lanes and access roads. Staff believes that the CECP site is no different and that access would be in compliance with all appropriate LORS.

Comment: Transmission lines present a difficulty to responders in case of an earthquake.

Response: Adequate vertical clearance for emergency response vehicles is required by the California Fire Code section 503.2.1 and NFPA 1 Uniform Fire Code section18.2.2.5.1.1. This project would comply with these codes.

Comment: Page 4.1-25 of the PSA, Facility Operation states, "…CECP operation would not require new employees because…workforce would be provided by…workforce which operates the existing Encina Power Station". Elsewhere, the PSA states that the CECP will be remotely controlled from the existing Encina Power Station. NRG has made public statements promising that it will be shutting down the Encina Power Station in the near future. If so, how will the CECP be operated? Cal ISO has expressed concerns about the reduced reliability of having power plants remotely controlled. Will there be workforce always at the CECP site to detect anomalous operating sounds that cannot be heard in a remote operating center, or in the event that emergency situations arise impeding the rapid deployment of personnel from the Encina plant to the CECP site? Currently, personnel have to pass through two electrically operated gates and, possibly, two train barrier gates, to traverse from one plant to another. We therefore recommend that the construction of an independently staffed control room at the CECP be a CEC licensing condition.

Response: Staff shares this concern and after careful review and evaluation, has proposed Condition of Certification **WORKER SAFETY-8** that would require the project owner to ensure that at a minimum, two workers are always present on the CEPC site (in the "bowl") who have real-time continuous communication with the control room when the power plant is operating.

KERRY SIEKMANN Comments

KS2009a – Kerry Siekmann/Terramar Assn. (tn: 49956). Comments on Preliminary Staff Assessment (Comments18, 20). 1/28/2009

Comment: During the January 7-8, 2009 CEC workshop, the Carlsbad Fire Chief reported that the location for the proposed CECP was difficult to access because of its location. If there were a major event at the plant, fire protection would be stretched beyond capacity. What about fire protection coverage for the neighborhoods close to the plant as well as the rest of the city during that event?

Response: As mentioned in the response to Power of Vision above, staff has made a considerable effort to review this matter and has reviewed all materials and opinions supplied to date. Staff believes that the CECP project can be built and operated in compliance with all fire protection LORS. As to fire protection coverage for the neighborhood during a major "event" at the power plant, staff believes that the CFD will be able to respond to the major event in the same manner regardless of whether the power plant is built or not built. Staff found no incremental or cumulative impact on the fire department.

Comment: The proposed widening of the 1-5 was public knowledge long before application was made for the proposed CECP. During the CEC workshop January 7-8, 2009, CEC staff informed us of the safety issues involved with the proposed widening of the 1-5. The 1-5 widening would encroach upon the berm making a fire road around the project impossible. The proposed CECP would sit dangerously close to the 1-5 putting the proposed CECP and the neighborhoods surrounding in peril. During the workshop the applicant announced that if the 1-5 widening occurred that they would not construct the project as submitted. Shouldn't the widening of the 1-5 be resolved before this project can even be considered?

Response: Please see response to Power of Vision and to the lengthy discussion in the FSA above

CITY OF CARLSBAD Comments

COC 2009a– City of Carlsbad /J Garuba (tn: 50009). City of Carlsbad Comments regarding the Preliminary Staff Assessment (pp 36-37). 1/30/2009

Comment: The City has concerns that in the event that emergency situations arise in the future, there will not be personnel available for rapid deployment. As it is currently proposed, personnel will have to pass through two electrically operated gates and, possibly, two train barrier gates, to traverse from one plant to another.

Response: Staff shares the concern of the City of Carlsbad and of Powwr of Vision regarding he porposal to not staff the CECP site but rather to have staff in a remote

control room at the EPS site. Staff believes that this staffing proposal is not adequate to ensure the safety, reliability, and security of the CECP site and proposes Condition of Certification **WORKER SAFETY-8**. This Condition would require the project owner to ensure that at a minimum, two workers are always present on the CEPC site (in the "bowl") who have real-time continuous communication with the control room when the power plant is operating.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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APPLICATION FOR CERTIFICATION FOR THE *CARLSBAD ENERGY CENTER PROJECT*

Docket No. 07-AFC-6
PROOF OF SERVICE
(Revised 12/8/2009)

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DECLARATION OF SERVICE

I, Mineka Foggie, declare that on December 17, 2009, I served and filed copies of the attached, Revised Sections for the Carlsbad (07-AFC-6)FSA Originally Dated November 2009 Air Quality (4.1) and Worker Safety Fire Protection (4.14) The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[http://www.energy.ca.gov/sitingcases/carlsbad/index.html].** The document has 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:

(C*heck all that Apply*)

For service to all other parties:

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

_x_ 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:

_x__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. 07-AFC-6
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.

Originally Sined By
Mineka Foggie

*indicates change