Carlsbad Energy Center LLC
1817 Aston Avenue, Suite 104
Carlsbad, CA 92008

Direct (760) 710-2146
Fax: (760) 710-2158

NRG

DOCKET	
07-AFC-6	
DATE	JUN 05 2009
RECD.	JUN 09 2009

June 5, 2009

Mr. Gerardo Rios
Air Division AIR-3
U.S. Environmental Protection Agency
75 Hawthorne Street
San Francisco, CA 94105

Subject: PSD Non-Applicability Determination Request for the Carlsbad Energy Center Power Project

Dear Mr. Rios:

On behalf of Carlsbad Energy Center LLC, we are requesting written confirmation from EPA that the proposed Carlsbad Energy Center Power (CECP) project will not trigger Prevention of Significant Deterioration (PSD) review.

Background

On September 17, 2007 an Application for Certification (AFC) for the CECP project was submitted to the California Energy Commission (CEC). As part of the permitting process for this proposed project an Application for an Authority to Construct/Determination of Compliance (ATC/DOC) was submitted to the San Diego Air Pollution Control District (SDAPCD) on September 12, 2007. The CECP project consists of the proposed replacement of three existing boilers at the Encina Power Station (Units 1, 2, and 3) with two new rapid startup natural gas-fired combined cycle gas turbines. The proposed CECP project also includes the installation of a new 246 hp Diesel emergency fire-pump engine. A complete description of the CECP project was included in the SDAPCD's engineering evaluation for the proposed permit for the CECP project. A copy of this document was submitted to EPA in November 2008 and is also enclosed as Attachment 1 for your reference.

PSD Applicability

For purposes of PSD applicability, the proposed CECP project is a modification to an existing major facility. Therefore, to determine whether the proposed CECP project will trigger PSD review as a major modification to an existing major facility, it is necessary to first determine whether the potential to emit for the proposed new equipment are significant under the PSD regulation. If the emission increase for the new equipment is significant for one or more attainment pollutants, the next step is to compare the facility-wide net emission change for each of these pollutants to the PSD significance levels. A project is a major modification subject to PSD review if there is a facility-wide net emission increase above a PSD significance level.

The potential to emit for the new equipment associated with the CECP project is shown below in Table 1. The detailed emission calculations are shown in the enclosed SDAPCD engineering evaluation for the proposed permit for the CECP project. Because the SDAPCD is currently in the process of issuing a new engineering evaluation for the final permit for the CECP project, the information in the enclosed SDAPCD document was used for this PSD applicability analysis. It is expected that the potential to emit for the new equipment and baseline emissions for existing equipment will be nearly identical in the SDAPCD engineering evaluation for the final permit compared to the emission levels discussed in this PSD analysis. Therefore, the issuance of the final SDAPCD permit is not expected to change the conclusions discussed in this analysis.

As shown in Table 1, the potential to emit for the proposed new equipment is above the PSD significance levels for the attainment pollutants NOx, CO, and PM_{10}. Therefore, for these pollutants it will be necessary to determine whether there is a facility-wide net emission increase above PSD significance levels. Because San Diego County is classified as a Federal non-attainment area for ozone, the PSD regulation does not apply to VOC emissions. Consequently, VOC emissions are excluded from this PSD regulatory analysis.

Table 1
CECP Project New Equipment Potential to Emit

Pollutant	Potential to Emit for New Equipment* (tons/year)	PSD Significance Level (tons/year)
NOx	72.8	40
CO	339.9	100
VOC	25.0	N/A
SOx	5.6	40
PM_{10}	39.0	15

Note (Table 1):
* See Attachment 1, Table 5c and permit condition 44 for potential to emit levels for new equipment (combined emissions from two gas turbines and fire-pump engine).

To determine the facility-wide net emission change of NOx, CO, and PM_{10} associated with the proposed installation of the new equipment, it is necessary to sum the new equipment emission increases with other emission increases and decreases at the power plant during the contemporaneous period. Under the PSD regulation the contemporaneous period begins five years before the start of construction of the proposed new equipment, and ends with the date of the emission increase associated with the new equipment [40 CFR 52.21.b.3.ii]. The final SDAPCD permit along with the CEC approval for the proposed CECP project is expected to occur by the end of 2009. Consequently, construction of the proposed new equipment could begin at the beginning of 2010. Therefore, for the proposed CECP project the contemporaneous period under the PSD regulation begins on January 1, 2005 (5-year lookback from start of construction) and ends when the proposed new equipment begins normal operation. Because this period includes the shutdown of Encina Power Station Units 1, 2, and 3, it is necessary to calculate the emission decrease associated with the shutdown of these units.

To calculate the emission decrease for the shutdown of Encina Units 1, 2, and 3, it is necessary to calculate the actual baseline emissions for these three units. While the Federal PSD regulation generally requires that baseline emissions for existing electric utility steam generating units be based on a 2-year average of actual emissions during the five years preceding the initial construction of new equipment (see 40 CFR 52.21.b.48.i), the PSD regulation allows the use of a different lookback period if requested by an applicant and approved by EPA. This flexibility allowed in the PSD regulation is an important tool given the difficulty in accurately estimating the future operation of existing units during the period between when a permit is processed/issued for new equipment and when construction begins on new equipment. An example of this flexibility in the allowed baseline period for existing units is a decision that EPA Region IX made for the Morro Bay Plant Modernization Project where EPA allowed a 10-year lookback period to establish the baseline emissions for existing utility boilers (see Attachment 2 for copy of this EPA decision).

Given the uncertainty of future operations/emissions of Encina Units 1, 2, and 3, we believe that it is appropriate for PSD applicability purposes to use actual emissions during the period from 2002 to 2006 to determine the emission decrease associated with the shutdown of Encina Units 1, 2, and 3. This period was selected because it matches the baseline period used by the SDAPCD for New Source Review (NSR) permitting purposes. In addition, we believe that the operation of the existing Encina boilers during this period is most representative of historical operation. As shown in the SDAPCD engineering evaluation (CECP PDOC, Table 5a), the maximum 2-year average NOx, CO, and PM_{10} emissions for Encina Units 1, 2, and 3 occurred during the period from 2004 to 2005. For purposes of this PSD analysis, the actual emissions for Encina Units 1, 2, and 3 for this two year period will be used as part of the net emission change calculation for the proposed CECP project.

In the following table, the potential to emit for the new units associated with the proposed CECP project are included with the contemporaneous emission decrease associated with the shutdown of Encina Units 1, 2, and 3 (based on actual emissions during 2004 and 2005). As shown in Table 2, the facility-wide net emission increase for the proposed CECP project is below PSD significance levels for NOx, CO, and PM_{10}. Therefore, the proposed CECP project does not trigger PSD review.

Table 2
PSD Applicability for CECP Project

Pollutant	Potential to Emit for New Equipment (tons/year)	Emission Reductions for Shutdown of Encina Units 1, 2 & 3 Based 2004-2005 Average (tons/year)	Net Emission Change (tons/year)	PSD Significance Levels (tons/year)
NOx	72.8	-38.9	33.9	40
CO	339.9	-296.1	43.8	100
PM_{10}	39.0	-37.6	1.4	15

As discussed above, the new equipment proposed as part of the CECP project is to replace existing Encina Units 1, 2, and 3. Because it is necessary for Encina Units 1, 2, and 3 to be able to provide power during the shakedown of the new equipment, there will be a period of time when the new units are undergoing shakedown and the existing Encina Units 1, 2, and 3 will operate periodically to provide power to the grid. The SDAPCD permit will prohibit the operation of a new unit if an existing Unit 1, 2, or 3 is operating (see permit condition 81). Consequently, there will be no simultaneous operation of the new units and Encina Units 1, 2, or 3 on an hourly basis. In addition, the SDAPCD permit will limit the annual emissions from existing Encina Units 1, 2, and 3 and the new units during this shakedown period (see permit conditions 82, 83, and 84). Furthermore, the SDAPCD permit includes a 180-day limit on the shakedown period for the new equipment (see permit condition 17). For PSD applicability purposes, the emission increase for the new equipment does not occur until these units become "operational." Under the PSD regulations a new unit becomes "operational" only after a reasonable shakedown period not to exceed 180 days (40 CFR 52.21.b.3.viii). This section of the PSD regulation allows for an overlap between the operation of existing units (which will be shutdown) and new units that must be operated for shakedown purposes. The SDAPCD permit limits discussed above will ensure that the proposed new equipment will not trigger PSD review during this shakedown period.

Based on the above information, we request written confirmation from EPA that the proposed CECP project will not trigger PSD review. If you have any questions or need any additional information, please do not hesitate to call me at (760) 710-2156.

Sincerely,

George L. Piantka

George L. Piantka, PE
Carlsbad Energy Center LLC

NRG

Enclosure

cc: Steve Moore, SDAPCD
John McKinsey, Stoel
Will Walters, CEC
Michael Monasmith, CEC
CEC Dockets Office (07-AFC-6)

ATTACHMENT 1

SDAPCD ENGINEERING EVALUATION
PDOC FOR CECP

AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

November 21, 2008

MIKE MONASMITH
PROJECT MANAGER
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO CA 95814

Dear Mr. Monasmith:

Enclosed for your review and comment is the District's Preliminary Determination of Compliance for the Carlsbad Energy Center LLC's proposed development of the Carlsbad Energy Center Project (District Applications No. 985745, 985747, and 985748), a 558 megawatt combined cycled power plant consisting of two natural-gas-fired combustion turbine generators, each with a heat recovery steam generator and emission control equipment, and a diesel fire pump engine, to be located at 4600 Carlsbad Blvd, Carlsbad, California, on the same grounds as the existing Encina Power Station. Also enclosed is a copy of the public notice that will be published on November 25, 2008.

The District performed an evaluation of the air pollution impacts of this proposal and the equipment is expected to operate in compliance with all applicable District Rules and Regulations and all applicable federal requirements. The proposed permit incorporates conditions necessary to ensure compliance with all federal and District requirements.

Please direct your written comments concerning the District's proposed action to the attention of Steven Moore, San Diego Air Pollution Control District, 10124 Old Grove Road, San Diego, CA 92131, within the 30-day public comment period commencing on November 25, 2008, and ending on December 24, 2008. Should you have any questions regarding this matter, please contact Steven Moore at (858) 586-2750.

Sincerely,

TOM WEEKS
Chief of Engineering

Enclosures

ID#: 333A

PRELIMINARY
DETERMINATION OF COMPLIANCE

CARLSBAD ENERGY CENTER PROJECT

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

Applications Number 985745, 985747, and 985748

November 20, 2008

Project Engineer	Camqui Nguyen
Senior Engineer:	Steven Moore
Application Numbers:	985745, 985747, and 985748
Site ID Number:	333A
Fee Schedule:	20F
BEC:	New

APPLICATION INFORMATION

Owner / Operator:	Carlsbad Energy Center, LLC
Mailing Address:	1817 Aston Ave, Suite 104 Carlsbad, CA 92008
Equipment Address:	4600 Carlsbad Blvd Carlsbad, CA 92008
Contact:	Tim Hemig
Company:	Carlsbad Energy Center LLC
Position:	Vice President
Phone Number:	(760) 710-2144
Fax Number:	(760) 710-2158

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APPENDICES

VI. ADDITIONAL ISSUES

PARTICULATE EMISSION RELATING TO THE USE OF RECLAIMED WATER FOR EVAPORATIVE COOLING

The proposed Siemens turbines have inlet air filters located upstream of the evaporative coolers. The evaporative cooler is turned on only during normal operation when ambient temperature is higher than 60°F. The particulate emission factor of 9.5 lbs/hr provided by the turbine vendor includes anticipated particulate matter from the evaporative cooler parameters. Therefore, no further particulate emissions from the evaporative cooler are included in the emission calculation.

COMMISSIONING PERIOD

After construction of the equipment has been completed, the applicant will be allowed a commissioning period of 120 days or 415 operating hours for each turbine, whichever comes sooner. During the 120-day commissioning period, the turbines will go through testing and tuning to ensure that the equipment is working properly and will be able to comply with all the proposed emission limits. However, during the initial startup, certain emissions standards must remain in effect. These include the 72.76 tons/yr limit for NOx, hourly mass emission limits for NOx and CO to ensure there will be no violation of any state or national ambient air quality standards, and the hourly concentration limits for NOx to ensure compliance with the District RACT and BARCT Rules 69.3 and 69.3.1, respectively. A CEMS will be required to be installed at the time of initial startup to monitor emissions during the commissioning period from each turbine.

Once the emissions control equipment has been installed and is in good working order, the turbines must meet all BACT/LAER standards and permit requirements. CEMS and source testing will be used to show compliance with these standards.

VII. CONCLUSIONS AND RECOMMENDATIONS

A Determination of Compliance confers the same rights and privileges as an Authority to Construct only when and if the California Energy Commission (CEC) approves the Application For Certification, and the CEC certificate includes all conditions of the Determination of Compliance as proposed by the Air Pollution Control Officer.

If operated in accordance with the conditions specified in this Preliminary Determination of Compliance, this equipment is expected to operate in compliance with all Rules and Regulations of the San Diego County Air Pollution Control District.

Originally Signed by Camqui Nguyen — 11/21/08

Project Engineer — Date

Originally Signed by Steven Moore — 11-21-08

Senior Engineer Approval — Date

I. PROJECT DESCRIPTION

Carlsbad Energy Center LLC (the Applicant) proposes to develop the Carlsbad Energy Center Project (CECP). This project is a combine cycled power plant with a total nominal base load gross power output of 558 MW. The CECP will utilize two Siemens SGT6-5000F Rapid Response Combined-Cycle (R2C2) combustion turbine generators (CTGs) equipped with steam power augmentation. The nominal gross power output is 208 megawatts (MW) with a corresponding heat input of 1976 million British thermal units per hour (MMBtu/hr) per turbine (without power augmentation at 61 °F average ambient temperature). The combustion turbines are also equipped with evaporative coolers that can be used cool the inlet air to each turbine to increase power during periods of high ambient temperature. Each CTG is followed by a heat recovery steam generator (HRSG) equipped with a selective catalytic reduction (SCR) system to reduce oxides of nitrogen (NOx) emission and an oxidation catalyst to control the carbon monoxide (CO) and volatile organic compounds (VOC) emissions. Steam from each HRSG will feed a steam turbine generator (STG) associated with that HRSG. This combination of a CTG with a HRSG and STG is referred to as a 1-on-1 combined-cycle power plant. By making use of the turbine exhaust heat to generate electricity with the steam turbine, combined-cycle power plants are significantly more efficient than other combustion turbine power plants.

The CECP is subject to the approval of the California Energy Commission (CEC) because the proposed power plant has a nominal rating greater than 50 MW. CECP filed an application for certification (AFC) with the CEC in September 2007 (07-AFC-6). The San Diego Air Pollution Control District (District) is considered a responsible agency for this approval and is required to submit a Preliminary Determination of Compliance (PDOC) and a Final Determination of Compliance (FDOC) to the CEC. Pursuant to District Rule 20.5 the FDOC review is functionally equivalent to an Authority to Construct review.

The CECP is located north of the intersection of Carlsbad Blvd. and Cannon Road in the city of Carlsbad in San Diego County. The project is proposed to be located in the northeast area of the existing Cabrillo Power I LLC's Encina Power Station, between the existing rail line and Interstate 5 (I-5). The two main power units of the project will be at the location of previously existing fuel oil tanks, which are currently being removed. The existing Encina Power Station is comprised of five utility boilers using steam to generate a total of approximately 1000 megawatts (MW) of electrical power at full load and having a combined rated heat input of 9874 million British thermal units per hour (MMBtu/hr). The boilers are permitted to burn both natural gas and, in cases of force majeure natural gas curtailments, No. 6 fuel oil. As part of the CECP, three existing utility boilers, known as Units 1, 2, and 3, at the Encina Power Station will be retired when the two combined-cycled turbines are fully operational (the other two utility boilers will remain in operation).

The project will be fueled by natural gas, which will be supplied by the San Diego Gas and Electric Company. No provisions for use of an alternative fuel in the event of a curtailment of the natural gas supply are proposed by the applicant.

II. EQUIPMENT DESCRIPTION

CECP has proposed to construct and operate the following equipment at this facility under application No. 985745, 985747, and 984748:

- Application 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.

- Application 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.

- Application 985748: An emergency fire pump engine, Cummins diesel engine, Model CFP6E-F35, as preliminarily proposed, rated at 246 brake horsepower, serial number to be determined.

III. PROCESS DESCRIPTION

The CECP consists of two power blocks, each having one CTG, one HRSG, and one condensing STG to provide a nominal 219 MW of electricity from the combustion turbine at full load with steam power augmentation and an additional 60 MW from the steam turbine. Thermal energy produced in the CTG through combustion of natural gas is converted to mechanical energy to drive the combustion turbine compressor and electric generator. The hot CTG exhaust gases at approximately 1,100°F enter the HRSG. In the HRSG, boiler feedwater is converted to steam and delivered to the STG. Steam leaving the steam turbine is condensed in an air-cooled surface condenser. Some of the steam from the HRSG is injected into the combustion turbine when steam power augmentation is employed.

The chosen CTG combines the fast starting capability of a simple-cycle gas turbine and the efficiency of a combined-cycle plant. The system is designed to start and reach 150 MW in ten minutes for a hot start and operate with combined-cycled efficiency in 45 minutes for a hot start and approximately 125 minutes for a cold start. The one-hour averaged NOx emission concentration is controlled to 2 parts per million by volume on a dry basis (ppmvd) and corrected to 15 percent oxygen (O_2) by a combination of the ULN combustor in the CTG and the SCR system located in the HRSG. In the SCR, ammonia will be injected into the CTG exhaust stream via nozzles located upstream of the catalyst module. Ammonia slip, or the concentration of unreacted ammonia in the HRSG exhaust stack, is limited to 5.0 ppmvd averaged over one hour. The HRSG is also equipped with an oxidation catalyst to control CO emissions leaving the HRSG exhaust stack to 2.0 ppmvd and VOC emissions to 2.0 ppmvd averaged over one hour. Exhaust from each HRSG will be discharged from individual 21.3-foot diameter stacks proposed to be 139-foot tall.

Each CTG is equipped with a continuous emission monitoring systems (CEMS) to sample, analyze, and record the natural gas fuel flow rate, NOx and CO concentration levels, and percentage of O_2 in the exhaust gas from the HRSG stack. The data will be transmitted to a data acquisition and handling system (DAHS) that will store the data and generate emission reports. The DAHS will also include alarms that will send signals to the plant distributed control system (DCS) when emission limits are approached or exceeded.

Because of regional system needs, the CECP is expected to operate primarily at intermediate average annual capacity factors. The facility is designed to operate between 25 and 100 percent of the base load (558 MW) to support dispatch service in response to customer electricity demands. The basic operational modes primarily affecting emissions are startups, shutdowns, short transients, and normal operations. The applicant has provided CTG performance data and emission data based on vendor guarantees for operations under different loads and different ambient temperatures. The expected emissions used in various aspects of the evaluation are presented in Tables 1a and 1b.

Startup is defined as the period beginning with ignition of a combustion turbine and lasting until the turbine can achieve the most stringent emission limits during normal operations (for this turbine the manufacturer has guaranteed turbine emissions at greater than 60% of base load capacity (124.8 MW). Shutdown is a period beginning with the lowering of the output of a combustion turbine below the minimum load necessary to achieve the most stringent emission limits during normal operations of its load capacity and ending when combustion has ceased. The minimum load is typically between 40% and 60% of the maximum load, depending on the combustion turbine. The applicant has proposed a minimum load threshold for a shutdown to be initiated of 114 MW, which is about 55% of the nominal base load (without steam augmentation).

Emissions during startups and shutdown are significantly higher than during steady state operation. However, because of its unique design, the plant will be able to startup and achieve emission limits much faster than conventional large combined-cycle power plants. The applicant estimates that there will be 300 startups per turbine per year and 300 shutdowns per turbine per year. Maximum annual emissions are calculated based on 300 hours with a startup, 300 hours with a shutdown, and 3,500 hours per year at full-load operation under average conditions for both CTGs.

The CECP may be completed in two phases expected to end in 2012 with the two combustion turbines sequentially achieving full operation. Phase I would consist of bringing one CTG/STG to full operation. Phase II would consist of bringing the remaining CTG/STG to full commercial operation. The completion of these two phases could be separated by as much as six months. Consequently, the three existing utility boilers may also be retired, or have their operations limited, in two phases. During the phase-in process the applicant has committed to not operating the combustion turbines and the steam boilers simultaneously, which minimizes emission impacts. However, to maintain grid reliability, maximum flexibility is desired in operating the existing boilers during the phase-in process when one or both CTG/STG units may not be fully operational.

IV. EMISSION ESTIMATES

COMBUSTION TURBINE GENERATOR EMISSIONS—STANDARD OPERATIONS

MAXIMUM HOURLY EMISSIONS

Project emissions of NOx, CO, sulfur oxides (SOx), VOC, 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) were estimated based on data supplied by the turbine manufacturer and emission limits in proposed permit conditions. The startup and shutdown, emission rates are provided by the turbine manufacturer. For steady state operations, emission rates for NOx, CO, and VOC are calculated based on emission concentration limits (in ppmvd at 15%O_2) in proposed permit conditions and exhaust flow rates in dry standard cubic feet per hour (dscfh) at average ambient temperature for annual emissions and cold ambient temperature for peak hour and peak day emissions:

> Emissions, lbs/hr = (concentration, ppmvd) x 10^{-6} x (exhaust flow rate, dscfh) x (molecular weight/standard molar volume).

Maximum hourly emissions of SOx are calculated based on the fuel heat input MMBtu/hr, and a SOx emission factor of 0.0021 lbs/MMBtu, which was derived from the maximum allowable sulfur content of 0.75 grains per 100 standard cubic feet based on the California Public Utility Commission (PUC) standard for pipeline natural gas. Emissions of PM10 are calculated based on vendor supplied guaranteed emission rates. Table 1a presents the hourly emission rates in pounds per hour (lbs/hr) for all five criteria pollutants at cold ambient temperature (37.4°F) and average ambient temperature (73.6°F). The PM2.5 emission rates are identical to PM10 emission rates since all particulate matter is considered to be PM2.5.

Table 1a – Maximum Turbine Emission Rates During Normal Operations			
Pollutant	Concentration, ppmvd @15%O2	Emission Rate at Cold Ambient Temperature, lb/hr	Emission Rate at Average Ambient Temperature, lbs/hr
NOx	2 (1- hour average)	15.1	14.13
CO	2 (3-hour average)	9.2	8.60
VOC	2 (3-hour average)	5.3	4.93
PM10	N/A	9.5	9.50
PM2.5	N/A	9.5	9.50
SOx	N/A	4.4	4.4

During a CTG startup, there are typically approximately 22 minutes of emission rates higher than emissions during normal operation. Therefore, hourly emission rates during startup are based on 22 minutes of high emission levels followed by 38 minutes of normal operation emission levels. During a typical CTG shutdown, there are approximately 53 minutes of normal operation followed by 7 minutes of higher emission levels. Therefore, typical hourly emission rates during shut down are based on 53 minutes of normal operation emission levels followed by 7 minutes of higher emission levels. For any hour when both a typical startup and a shutdown occur, there would be 22 minutes of startup emissions, 31 minutes of normal emissions and 7 minutes of shutdown emissions. Because there is some variability in emissions during startup and shutdown, the hourly emissions for CO and NOx are estimated at twice the expected emission value. Table 1b presents the maximum emission rates for each turbine during startup and shutdown in pounds per hour. The maximum emission rates of PM10 and PM2.5 are not affected during startup and shutdown and the emission limit for normal operations remains in effect for these periods. The maximum emission rate of SOx is reduced because the turbine operates at low loads (and low heat input) during startups and shutdowns.

Table 1b – Maximum Turbine Emission Rates During Startup and Shutdown			
Pollutants	Startup Emissions, lbs/hr	Shutdown Emissions, lbs/hr	Startup and Shutdown, lbs/hr
NOx	69.2	47	86
CO	545	286	814
VOC	16.3	10	21
PM10	9.5	9.5	9.5
PM2.5	9.5	9.5	9.5
SOx	<4.4	<4.4	<4.4

Maximum Daily Emissions

Maximum daily emissions from each combustion turbine are calculated based on the assumption that each turbine operates up to 24 hours per day, of which 6 hours include a startup, 6 hours include a shutdown, and 12 hours for steady state operation at cold ambient temperature, as follows:

Daily emissions = (startup emissions, lbs/hr) x (6 hours/day) + (shutdown emissions, lbs/hr) x (6 hours/day) + (steady state operation emissions, lbs/day) x (12 hours /day)

Table 1c presents estimated maximum daily emissions from the combustion turbines in pounds per day (lbs/day).

Table 1c – Expected Maximum Turbine Daily Emissions		
Pollutants	Emissions from Each Turbine lbs/day	Emissions from Both Turbines lbs/day
NOx	877	1754
CO	5102	10205
VOC	219	439
PM10	228	456
PM2.5	228	456
SOx	106	211

Maximum Annual Emissions

Maximum annual emissions for the combustion turbines are estimated based on the assumption that each turbine operates up to 4100 hours per year, of which 300 hours are for startup, 300 hours are for shutdown, and 3500 hours for steady state operation at average ambient temperature, as follows:

Annual emissions = (startup emissions, lbs/hr) x (300 hours/year) + (shutdown emissions, lbs/hr) x (300 hours/year) + (steady state operation emissions, lbs/day) x (3500 hours /years)

Table 1d presents estimated maximum turbine annual emissions in tons per year (tons/yr).

Table 1d – Maximum Turbine Annual Emissions		
Pollutants	Emissions from Each Turbine, tons/yr	Emissions from Both Turbines, tons/yr
NOx	37.77	75.54
CO	108.65	217.3
VOC	12.52	25.05
PM10	19.48	38.95
PM2.5	19.48	38.95
SOx	9.02	18.04

EMERGENCY FIRE PUMP ENGINE EMISSIONS

At a minimum, the diesel emergency fire pump engine must comply with Tier 2 emission standards for EPA certified engines of model year 2008. Daily emissions from the engine are calculated based on one hour of operation and annual emissions are calculated based on 50 hours of operation. Table 2a presents the engine hourly, daily, and annual emissions.

Table 2a – Emergency Fire Pump Engine Emissions			
Pollutant	Engine Hourly Emissions, lbs/hr	Engine Daily Emissions, lb/day	Engine Annual Emissions, tons/yr
NOx	2.08	2.08	0.052
CO	0.24	0.24	0.006
VOC	0.05	0.05	0.00125
SOx	0.0027	0.0027	0.00007
PM10	0.035	0.035	0.0008
PM2.5	0.035	0.035	0.0008

PROJECT EMISSIONS—STANDARD OPERATIONS

Total emissions from the project include emission from both combustion turbines and emissions from the emergency fire pump engine. Table 3a and 3b present the estimated maximum project total daily and annual emissions pounds per day and tons per year, respectively.

Table 3a – Maximum Project Total Daily Emissions			
Pollutant	Turbines Total Daily Emissions, lbs/day	Engine Daily Emissions, lbs/day	Project Total Daily Emissions, lbs/day
NOx	1754.04	2.08	1756.13
CO	10204.52	0.24	10204.76
VOC	438.70	0.05	438.75
SOx	211.06	0.0027	211.06
PM10	456.04	0.035	456.04
PM2.5	456.04	0.035	456.04

Table 3a – Maximum Project Total Annual Emissions			
Pollutant	Turbines Total Annual Emissions, tons/yr	Engine Annual Emissions, tons/yr	Project Total Annual Emissions, tons/yr
NOx	75.54	0.052	75.6
CO	217.3	0.006	217.3
VOC	25.05	0.00125	25.1
SOx	18.04	0.00007	18.04
PM10	38.95	0.0008	39
PM2.5	38.95	0.0008	39

Toxic air contaminant emissions, or noncriteria pollutant emissions, are presented in details in the Toxic Health Risk Assessment Section in Appendix B of this determination.

COMBUSTION TURBINE GENERATOR EMISSIONS—COMMISSIONING PERIOD

Following construction of the power plant and prior to full commercial operation, the combustion turbine generators, the steam turbine generator, emission control equipment, heat recovery steam generator and other equipment will be tested and tuned. During this period, because the CTG burners may not yet be tuned for optimal emissions and because the post combustion control equipment will not yet be in full operation, emissions from the plant will be higher than normal operating emissions. The plant is expected to operate 415 hours per turbine over approximately 49 operating days during this commissioning period, which includes hours of operation at different load levels and with and without emission control equipment. Commissioning emission data provided by the turbine vendor consist of different emission scenarios corresponding to different phases of the commissioning period. Table 4a presents the expected commissioning maximum hourly emission rates. In order to minimize emission impacts during the commissioning period, emission rates for NOx and CO for both turbines combined will be limited to the levels expected for one turbine in commissioning mode and one turbine in normal operation mode (including startups and shutdowns) by proposed permit conditions.

Table 4a –Maximum Turbine Hourly Emissions During Commissioning

Pollutants	Single Turbine Emissions, lbs/hr	Allowed Combined Turbine Emissions, lbs/h
NOx	200	286
CO	3813	4627
VOC	164	327.5
SOx	4.4	8.80
PM10	9.50	19.0
PM2.5	9.50	19.0

For a single combustion turbine, expected maximum daily emissions during commissioning are based on the peak emission day for each pollutant forecast from the projected commissioning schedule. Because of the proposed hourly limits on NOx and CO emission rates during commissioning, peak daily emissions during commissioning from both turbines for NOx and CO are estimated as the sum of the peak commissioning emissions for one turbine and expected maximum daily emissions from the other turbine under normal operations. For the other pollutants, peak daily commissioning emissions are the sum of peak commissioning emissions for each turbine. Table 4b presents the maximum daily commissioning emissions. The entire commissioning period may take up to 120 calendar days to allow time for reviewing test and turning information and operational adjustments to the combustion turbines and associated plant equipment.

Table 4b – Maximum Daily Emissions During Commissioning		
Pollutants	Single Turbine Emissions, lbs/day	Combined Turbine Emissions, lbs/day
NOx	1755	2632
CO	43712	48814
VOC	1310	2620
SOx	106	211
PM10	221	442
PM2.5	221	442

Total commissioning emissions are based on turbine vendor projected emission data for the entire commissioning period. The emergency fire pump engine is not expected to operate during the turbine commissioning period. Table 4c presents total commissioning emissions. Note that these emissions include all emissions from startups and shutdowns during the commissioning period.

Table 4c – Total Turbine Commissioning Emissions		
Pollutants	Single Turbine Emissions, tons	Combined Turbine Emissions, tons
NOx	6.24	12.48
CO	65.17	130.34
VOC	3.48	6.96
SOx	0.28	0.56
PM10	1.96	3.92
PM2.5	1.96	3.92

PROJECT EMISSIONS—COMMISSIONING PERIOD

For the combustion turbines' first year of operation during which both commissioning operations and normal operations take place, total maximum project emissions are estimated based on 415 hours of commissioning emissions, 300 hours of maximum startup emissions, 300 hours of maximum shutdown emissions, and 2,600 hours of maximum normal operation emissions, and estimated maximum emissions from the emergency fire pump engine. Table 4d presents the estimated total maximum annual emissions for the project for a year with commissioning.

Table 4d – Total Project Emissions During Year With Commissioning			
Pollutants	Combined Turbine Commissioning Emissions, tons/yr	Combined Turbine Normal Operation Emissions and Engine Emissions, tons/yr	Total Project Emissions, tons/yr
NOx	12.48	62.87	75.35
CO	130.34	209.56	339.90
VOC	6.96	15.09	22.05
SOx	0.56	14.08	14.64
PM10	3.92	30.40	34.32
PM2.5	3.92	30.40	34.32

V. RULES ANALYSIS

DISTRICT AND FEDERAL NSR AND PSD REGULATIONS

Rule 20.1(c)(35) – Major Stationary Source

Major stationary source means any emission unit or stationary source which has, or will have after issuance of a permit, an aggregate potential to emit one or more air contaminants, including fugitive emissions, in amounts equal to or greater than any of following emission rates:

Air Pollutant	Emission Rates (tons/yr)
PM10	100
NOx	50
VOC	50
SOx	100
CO	100
Lead (Pb)	100

Major source status is only relevant for pollutants for which the District does not attain a national air quality standard. Since the District attains all national ambient air quality standards with the exception of ozone, major source status is only relevant for NOx and VOCs, both of which are ozone precursors. In particular, the major modification thresholds (see below) apply for contemporaneous emission increases and associated requirements for NOx and VOCs. Based on its potential to emit, the Encina Power Station is an existing major stationary source for both NOx and VOCs.

Rule 20.1(c)(58) – Prevention of Significant Deterioration (PSD) Stationary Source and 40 CFR 52.21

Because the Encina Power Station is a fossil fuel fired steam electrical generating plant with a heat input rating greater than 250 MMBtu/hr, PSD Stationary Source status is defined by an aggregate potential to emit one or more air contaminants in amount equal to or greater than any of the following emission rates:

Air Pollutant	Emission Rates (tons/yr)
PM10	100
PM2.5	100
PM	100
NO_2	100
VOC	100
SO_2	100
CO	100
Lead (Pb)	100

Since the Encina Power Station's potential to emit exceeds the PSD stationary source threshold for at least one pollutant (e.g., NOx, which is considered NO_2 for purposes of PSD determinations), it is an existing PSD stationary source. District Rule 20.1 does not explicitly address PM2.5 or particulate matter of all sizes (PM). However, those pollutants are addressed by 40 CFR 52.21 et. seq., which is EPA's implementation of PSD rules and is an applicable requirement for the CECP.

Rule 20.1(c)(16), 40 CFR §52.21, and 40 CFR Appendix S to Part 51– Contemporaneous Emission Increase

Contemporaneous emission increase is defined in Rule 20.1 (c)(16) as the sum of emission increases from new or modified emission units occurring at a stationary source within the calendar year in which the subject emission units is expected to "commence operation" and the preceding four calendar years, including all other emission units with complete applications under District review and which are expected to commence operation within such calendar year. The emission increases for new units are based on the new units' potential to emit (PTE) as limited by proposed permit limits pursuant to Rule 20.1(d)(1)(i)(A). The emission increases may also be reduced by actual emission reductions at the facility. In this case, the applicant is proposing to create actual emission reductions by shutting down three existing utilities boilers (the two other utility boilers, Units 4 and 5, will remain in operation).

Rule 20.1(c)(16) does not address when the actual emission reductions must occur relative to the initial startup of new or modified equipment. However, for replacement units, up to 180 days from the initial startup of new equipment is allowed before the actual emission reduction must be effective in federal implementations of PSD regulations [40 CFR §52.21(b)(3)(ii) and (viii)] and nonattainment NSR regulations [40 CFR Appendix S to Part 51 II.a.6.ii. and vi.] to allow a reasonable shakedown period for the new equipment.

The CECP is replacing the three existing utility boilers known as Units 1, 2, and 3 at the Encina Power Station. At the end of Phase I of the project, full commercial operation for one of the CTG/STG systems, part of the electrical generating capacity of these three boilers will be replaced. The generating capacity of Units 1, 2, and 3 will be completely replaced by the end of Phase II when the second CTG/STG system is fully operational. Since the new CTG/STG systems are replacing these three existing boilers, simultaneous operation of the CTG/STGs and the three existing boilers is not allowed during the phase-in period and the boilers must be shutdown completely at the end of Phase II.

In this case, 180 days is a reasonable shakedown time for each new CTG and associated equipment. This shakedown period allows 120 days for new equipment commissioning, which includes achieving the most stringent permitted emission limits, and an additional 60 days for the new equipment to reach full commercial operational status including verification testing both for emissions and operational reliability. The shakedown periods for the two CTG/STG systems could proceed in parallel or sequentially.

<u>Postproject Contemporaneous Emission Increase</u>

Currently, the proposed CECP is expected to commence full commercial operation in 2012. Full commercial operation includes having both CTGs and associated STGs fully operational with their emission and operational status verified. Therefore, the five-year contemporaneous window in which emission increases need to be evaluated is the time period from 2008 through 2012. For the years 2008 to 2012, there are no expected emission increases at the Encina Power Station. In addition, the District has no applications associated with the Encina Power Station other than the CECP that expect to commence operation at any time in the future. Therefore, the only emission increases for contemporaneous emission increases are those associated with the CECP.

Existing Units 1, 2, and 3 at the Encina Power Station will be shut down and retired prior to full commercial operation of both new CTG/STG systems. The shutdown of these boilers will result in actual emissions reduction at the site. Rule 20.1(c)(16)(i) allows the sum of emission increases to be reduced by actual emission reductions occurring at the stationary source. Rule 20.1(d)(4)(ii)(A) defines actual emission reductions from the shutdown of an emission unit as those calculated based on the emission unit's preproject actual emissions.

Preproject actual emissions are based on actual emissions occurring over the 5-year period preceding the receipt of the application. Rule 20.1(d)(2)(i)(B) requires the actual emissions to be averaged over the total operational time period within the five-year period if a representative two-year operating time period does not exist. Since the Application for Certification (AFC) for this CECP was submitted to the CEC in 2007, the preceding five years in consideration for actual emission reduction estimates are 2002, 2003, 2004, 2005, and 2006. Since the District determined that there was not a representative two-year operating time period for Units 1, 2, and 3 of the Encina Power Station during these five years, the 5-year average of emissions from boilers Units 1, 2, and 3 determines pre-project actual emissions for those units. In the case of NOx, the emissions are based on CEMS data. For the other pollutants, emissions are based on the annual District emission inventory, except that PM10, PM 2.5, and total particulate (PM) emissions were adjusted from the inventory values based on EPA's AP-42 emission factors, because the District emission inventory for the existing utility boilers reports all PM as PM10. Only PM2.5 results from gas-firing of the existing units. However, No. 6 fuel oil is burned a few hours per year to demonstrate the reliability of the backup fuel. This necessitates the adjustment of the emission inventory of PM2.5 and PM10 since No. 6 fuel oil combustion produces some particulate matter greater than 2.5 microns and some particulate matter greater than 10 microns.

Table 5a presents the data used to determine the preproject actual emissions.

Table 5a – Boiler Units 1,2, and 3 Averaged Actual Emission						
Pollutants	2002 Actual Emissions, tons/yr	2003 Actual Emissions, tons/yr	2004 Actual Emission, tons/yr	2005 Actual Emission, tons/yr	2006 Actual Emission, tons/yr	Baseline Average Emissions, tons/yr
NOx	39.5	30.8	46	31.8	16.2	32.86
CO	494.5	228	351	241.1	110	284.9
VOC	16.2	15.2	23	16	8.3	15.74
SOx	9.5	12.5	2.6	2	2.7	5.9
PM10	35.15	27.64	44.10	31.14	17.55	31.51
PM 2.5	34.91	27.31	44.10	33.07	17.49	31.38
PM	35.4	28	44.1	33.2	17.6	31.66

For informational purposes, Table 5b presents the contemporaneous emission increases at the site without consideration of proposed permit limits after completion of all phases of the CECP and the retirement of existing Units 1, 2, and 3. The increase is calculated based on the total emission increase resulting from the CECP and actual emission reductions due to shut down of the three existing utility boilers. The maximum annual emissions are based on the larger of the emissions during a standard operation year or a commissioning year.

Table 5b –Emission Increases for Estimated Maximum CECP Emission Increases			
Pollutants	Estimated Maximum Emission Increases from CECP, tons/yr	Actual Emission Reductions from Units 1, 2, and 3, tons/yr	Maximum Potential Emission Increase, tons/yr
NOx	75.6	32.86	42.74
CO	339.9	284.9	55.0
VOC	25.1	15.7	9.4
SOx	18	5.9	12.1
PM10	39	31.5	7.5
PM 2.5	39	31.4	7.6
PM	39	31.7	7.3

However, the actual contemporaneous emission increase, which includes limitations on potential to emit of the new equipment accepted by the applicant, are shown in Table 5c. These limits are applicable from the first date a turbine has an initial startup. These limits were accepted by the applicant to ensure annual emissions did not exceed those upon which the Ambient Air Quality Analysis (AQIA) was based (see below) and to ensure emissions were limited to below the major modification and PSD modification thresholds (see below). Note that all particulate matter emissions from the CECP are considered to be PM2.5, so a limit on PM10 suffices to limit PM2.5, PM10, and PM.

Table 5c – Contemporaneous Emission Increases			
Pollutants	Allowed PTE Increases From CECP, tons/yr	Actual Emission Reductions from Units 1, 2, and 3, tons/yr	Contemporaneous Emission Increase, tons/yr
NOx	72.76	32.86	39.9
CO	339.90	284.9	55
VOC	25.0	15.74	9.26
SOx	5.6	5.9	-0.3
PM10	39	31.5	7.5
PM2.5	39	31.4	7.6
PM	39	31.7	7.3

<u>Contemporaneous Emission Increases After Completion of the Phase I Shakedown Period</u>

The CECP contemplates starting operation of the two CTG/STG units sequentially. The second unit to reach full commercial operation (Phase II) may complete its shakedown period significantly later than the first (Phase I). To allow for this possibility, contemporaneous emission increases were evaluated for the operation of a single combustion turbine and the emergency water pump only.

The applicant agreed to accept emission limits, as necessary, on the single combustion turbine and emergency water pump combined and Units 1, 2, and 3 to limit emissions below the PSD modification thresholds and, in the case of NOx, limit emissions to a level consistent with the emission offsets provided (see below). Consistent with the necessary shakedown period for the CTG/STG system (not to exceed 180 days), the actual emission reductions need not occur until the end of shakedown period for the first turbine to reach full commercial operation (i.e., before that time emissions from the three existing utility boilers are not limited). Therefore, the emission limits for Units 1, 2, and 3 do not apply until the end of the 180-day shakedown period for Phase I. However, the limits on potential to emit for the combustion turbine and emergency engine combined apply from the first date a combustion turbine has an initial startup. During the shakedown periods for both turbines the limits on potential to emit for both combustion turbines and the emergency engine listed in Table 5c are also in effect, which serves to limit the potential to emit of all the emission units associated with the CECP during both phases of the shakedown period.

The Phase I limits in Table 5d and 5e are no longer applicable at the end of the shakedown period for the second CTG/STG system (i.e., the end of Phase II). At that time the limits in Table 5c apply to both combustion turbines and the emergency generator combined, and Units 1, 2, and 3 must permanently cease operation.

Table 5d presents the resulting actual emission reductions from emission limitations on the three existing utility boilers at the end of Phase I and Table 5e presents the resulting contemporaneous emission increases and limitations on the potential to emit for one turbine and the emergency fire pump engine combined for Phase I.

Table 5d – Phase I Actual Emission Reductions

Pollutants	Baseline Emissions from Units 1, 2, and 3, tons/yr	Allowed Emissions from Units 1, 2, and 3, tons/yr	Actual Emission Reductions, tons/yr
NOx	32.86	16.33	16.53
CO	284.9	214.85	70.05
VOC	15.7	No Limit	0
SOx	5.9	No Limit	0
PM10	31.51	26.91	4.6
PM2.5	31.38	21.78	9.6
PM	31.66	No Limit	0

Table 5e – Phase I Contemporaneous Emission Increases			
Pollutants	Allowed Emission Increases from One Turbine and Emergency Fire Pump Engine, tons/yr	Actual Emission Reductions from Units 1, 2, 3, tons/yr	Contemporaneous Emission Increase, tons/yr
NOx	36.40	16.53	19.87
CO	169.95	70.05	99.9
VOC	12.5	0	12.5
SOx	2.8	0	2.8
PM10	19.5	4.6	14.9
PM2.5	19.5	9.6	9.9
PM	19.5	0	19.5

Rule 20.1(c)(33) – Major Modification

Major modification is defined as a physical or operational change which results in a contemporaneous emissions increase for a pollutant or its precursors for which the District does not attain the federal ambient air quality standards at an existing major stationary source for that pollutant. As the only national ambient air quality standard San Diego County does not attain is the 8-hour ozone standard, only the ozone precursors NOx and VOCs are evaluated to determine whether a major modification occurs. The major modification threshold for both NOx and VOCs is a contemporaneous emission increase of the pollutant equal to or greater than 25 tons per year. The contemporaneous emission increase of NOx resulting from the CECP is 39.9 tons per year (Table 5c), which is higher than the 25 tons per year threshold for a major modification. Therefore, the proposed CECP is a major modification to the facility for NOx. The CECP is not a major modification for VOCs because the contemporaneous emission increase is only 9.31 tons per year, less than the major modification threshold.

Rule 20.1(c)(57) PSD Modification and 40 CFR 52.21

A PSD modification is a contemporaneous emission increase occurring at a modified PSD stationary source equal to or greater than the following emission rates:

Pollutant	Emission Rates (tons/yr)
PM	25
PM10	15
PM2.5	10
NO_2	40
VOC	40
SO_2	40
CO	100
Lead (Pb)	0.6

(All NOx is considered NO2 for the purpose of PSD determinations).

Without considering proposed annual limits, the contemporaneous emission increase of NOx is 42.74 tons per year, which is higher than the 40 tons per year threshold for a PSD modification. However, the applicant has accepted a limit of 72.76 tons per year of NOx emissions in the proposed permit to keep the project NOx emissions below the PSD modification threshold. None of the other pollutant contemporaneous emission increases exceed the PSD modification level (see Tables 5b and 5c, there are no lead emissions from the CECP).

Rule 20.3(d)(1)- Best Available Control Technology(BACT)/Lowest Achievable Emission Rate(LAER)

Subsection 20.3(d)(1)(i) of the rule requires that Best Available Control Technology (BACT) be installed on a new or modified emission unit on a pollutant-specific basis if emissions exceed 10 lbs/day or more of PM10, NOx, VOC or SOx. Subsection 20.3(d)(1)(v) also requires that Lowest Achievable Emission Rate (LAER) be installed for a new emission unit which results in an emission increase which constitutes a major modification. Emergency equipment is exempt from the LAER requirements of 20.3(d)(1)(v).

LAER cannot be less stringent than BACT and is required only for air contaminants and their precursors for which the stationary source is major and for which the district is classified as non-attainment of a national ambient air quality standard. Because the District attains the National Ambient Air Quality Standards (NAAQS) for CO, SO_2, PM2.5 and PM10, LAER does not apply to these pollutants. LAER, however, applies to NOx emissions since the CECP constitutes a major modification for NOx. For the combustion turbines, BACT applies for VOC, SOx, and PM10 emissions because their emissions are more than 10 pounds per day.

Rule 20.3(d)(1)(vi) also requires that for a new or modified emission unit at a PSD stationary source with an emission increase of one or more air contaminant which constitutes a new PSD stationary source or PSD modification, BACT shall apply for each such air contaminant. Although the contemporaneous emission increase for CO is less than the PSD modification threshold, the emission increase for CO from the CECP itself is larger than the PSD stationary source threshold. Therefore, the CO emissions are also subject to BACT.

In summary, based on emission estimates, LAER is triggered for NOx and, for the combustion turbines, BACT is triggered for CO, VOC, SOx, and PM10. For the emergency fire pump engine, BACT is triggered only for CO as part of the CECP because the potential to emit VOC, SOx, and PM10 is less than 10 pounds per day for the emission unit.

<u>Oxides of Nitrogen (NOx)—Combustion Turbines, Normal Operations</u>

The turbine vendor has guaranteed a NOx emission level of 2.0 ppmvd at 15% oxygen at greater than 60% load with the SCR add-on air pollution control system to control NOx installed. The applicant has proposed a NOx emission limit of 2.0 ppmvd averaged over one hour as BACT and LAER during normal operations.

According to the ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT/LAER for NOx emissions from combined-cycle combustion turbine is either a NOx emission concentration of 2.5 ppmvd based on a one-hour averaging period or 2.0 ppmvd based on a three-hour averaging period, both calculated at 15% oxygen. However ARB is revising its BACT/LAER guidance for power plants to include limits achieved or proposed by more recent projects. The District consulted the BACT / LAER Clearinghouses, other air districts, EPA, and ARB for recent BACT/LAER determinations. A number of combined-cycle power plants of comparable size were permitted with NOx at 2.5 ppmvd or lower, averaged over one hour. The District examined the following projects with NOx emission limits less than 2.5 ppmvd at 15% oxygen:

- The Sithe Mystic Development LLC power plant is permitted by the Massachusetts Department of Environmental Protection and has been in commercial operation since 2002. This plant has been in compliance with a 2 ppmvd NOx limit averaged over one hour, excluding startups and shutdowns, with less than 0.1% of operating time exceeding this standard.

- The Avenal Power Center is proposed to be permitted by the San Joaquin Valley Air Pollution Control District in a Preliminary Determination of Compliance issued on July 11, 2008 [CEC Docket No. 08-AFC-01]. This plant is proposed to be permitted at 2.0 ppmvd of NOx averaged over one hour.

- The Diamond Wanapa, L.P, power plant is permitted by EPA, Region X, at 2 ppmvd of NOx averaged over three hours. This plant has not been constructed yet.

- The El Segundo Power, LLC is proposed to be permitted by South Coast Air Quality Management District in a Preliminary Determination of Compliance issued on August 22, 2008 [CEC Docket No. 00-AFC-14C (Amendment Proceeding)]. This plant has two rapid response combined-cycle Siemens turbines identical to the combustion turbines proposed for the CECP, and is proposed to be permitted at 2.0 ppmvd of NOx averaged over one hour.

- The Palomar Energy Center in Escondido permitted by the District has been able to comply with 2.0 ppmvd NOx limit averaged over one hour during normal operations, excluding startup and shutdown periods, limited periods of low load operation, rapid transients, and tuning of the combustors and the SCR.

Based on the above information, the District has preliminarily determined that BACT for NOx should be 2.0 ppmvd at 15% oxygen, averaged over one hour for normal operation with appropriate exclusions to address technical feasibility for startups and shutdowns and other abnormal periods of operation. As defined in Rule 20.1(c)(32), LAER means the most stringent emission limitation, or most effective emission control device or control technique, unless such emission limit , device or technique is not achievable. An emission limit of 2.0 ppmvd NOx at 15% averaged over one hour is considered by the District to be the current most stringent emission limit for larger combined-cycle combustion turbines that is achievable. Therefore, this standard also applies as LAER for NOx for such turbines.

As proposed by the applicant, the CECP combustion turbines will be equipped with dry ultra low-NOx combustors and a selective catalytic reduction (SCR) that in combination are designed to achieve 2.0 ppmvd NOx averaged over one hour. The District is unaware of any demonstrations that alternative technologies for control of NOx such as the XONON™ catalytic combustors or EMx™ (SCONOX) catalyst system can achieve NOx emission levels lower than the combination of dry ultra low-NOx combustors and SCR on large (greater than 50 MW) natural-gas-fired combustion turbines. A continuous emission monitoring system (CEMS) and annual source testing will be used to confirm compliance with this emission limit.

Carbon Monoxide (CO)—Combustion Turbines, Normal Operations

The turbine vendor has guaranteed a CO emission level of 2.0 ppmvd at 15% oxygen at greater than 60% load with the oxidation catalyst add-on air pollution control system to control CO installed. The applicant has proposed a CO emission limit of 2.0 ppmvd averaged over one hour as BACT and LAER during normal operations.

According to ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT for CO emissions from this equipment is 6.0 ppmvd based on a 3-hr averaging period, calculated at 15 % oxygen. Because the ARB Guidance is being updated, other air districts, EPA, and ARB Clearinghouses, were been consulted for more recent determinations. The District examined the following projects with CO emission limits less than 4.0 ppmvd at 15% oxygen:

• The Sithe Mystic Development LLC power plant in Massachusetts is permitted at 2.0 ppmvd CO averaged over one hour with startups and shutdowns excluded.

• The Avenal Power Center is proposed to be permitted by the San Joaquin Valley Air Pollution Control District in a Preliminary Determination of Compliance issued on July 11, 2008 [CEC Docket No. 08-AFC-01]. This plant is proposed to be permitted at 4.0 ppmvd of CO averaged over three hours.

• The Magnolia Power Project is permitted by the South Coast Air Quality Management District at 2.0 ppmvd CO averaged over one hour. This plant has not been built yet.

• The El Segundo Power, LLC is proposed to be permitted by South Coast Air Quality Management District in a Preliminary Determination of Compliance issued on August 22, 2008 [CEC Docket No. 00-AFC-14C (Amendment Proceeding)]. This plant has two rapid response combined-cycle Siemens turbines identical to the combustion turbines proposed for the CECP, and is proposed to be permitted at 2.0 ppmvd of CO averaged over one hour.

• The Palomar Energy Center in Escondido has been able to comply with 4.0 ppmvd CO limit averaged over three hours during normal operations, excluding startup and shutdown periods and periods of low-load operations and tuning. District experience based on CEMS data indicates that it likely achieves 2.0 ppmvd averaged over one hour.

Based on the information above, the District has preliminarily determined a CO limit of 2.0 ppmvd calculated at 15% oxygen averaged over one hour to be BACT for CO for the CECP combustion turbines for normal operation with appropriate exclusion to address technological feasibility for startups and shutdowns and other abnormal periods of operation. To meet this requirement, the applicant evaluated the use of an oxidation catalyst, which is the only post-combustion technology currently available to control CO, VOC, and toxic emissions. This technology is acceptable as BACT for CO. The applicant will therefore use an oxidation catalyst to meet the BACT level of 2.0 ppmvd at 15 % oxygen on a one-hour average. A CEMs and annual source testing will be used to confirm compliance with this limit.

Volatile Organic Compounds (VOCs)—Combustion Turbines, Normal Operations

The turbine vendor has guaranteed a VOC emission level of 2.0 ppmvd at 15% oxygen at greater than 60% load with the oxidation catalyst add-on air pollution control system to control VOCs installed. The applicant has proposed a VOC emission limit of 2.0 ppmvd averaged over one hour as BACT and LAER during normal operations.

According to ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT for VOC emissions from this type of equipment is 2.0 ppmvd based on a three-hour averaging period, calculated at 15 % oxygen. Because the ARB Guidance is being updated, other air districts, EPA and ARB Clearinghouses, have been consulted for more recent determinations. The District examined the following projects with VOC emission limits of 2.0 ppmvd or less at 15% oxygen:

- The Sithe Mystic Development LLC power plant in Massachusetts was permitted at 1.7 ppmvd VOC averaged over one hour. The Sithe Mystic Power Plant combustion turbine is a Mitsubishi 501G turbine. This turbine is considerably larger and a newer generation G-class combustion turbine as compared the Siemens F-class turbine proposed for this project.

    - The Magnolia Power Project was permitted by the South Coast Air Quality Management District at 2 ppmvd VOC averaged over one hour. This plant has not been built yet.

    - The Avenal Power Center is proposed to be permitted by the San Joaquin Valley Air Pollution Control District (SJVAPCD) in a Preliminary Determination of Compliance issued on July 11, 2008 [CEC Docket No. 08-AFC-01]. This plant is proposed to be permitted at 1.4 ppmvd of VOCs averaged over three hours. However, SJVAPCD has indicated in communications to the District that the most stringent limit for CTGs larger than 160 MW that are actually operating in the SJVAPCD is 2.0 ppmvd of VOCs averaged over three hours, with clock hours that include a portion of a startup or shutdown period excluded.

- The El Segundo Power, LLC is proposed to be permitted by South Coast Air Quality Management District in a Preliminary Determination of Compliance issued on August 22, 2008 [CEC Docket No. 00-AFC-14C (Amendment Proceeding)]. This plant has two rapid response combined-cycle Siemens turbines identical to the combustion turbines proposed for the CECP, and is proposed to be permitted at 2.0 ppmvd of VOC averaged over one hour.

- The Palomar Energy Center in Escondido has been able to comply with 2.0 ppmvd VOC limit averaged over three hours during normal operations, excluding startup and shutdown periods, limited periods of low load operation, and tuning. District experience based on CO CEMS data indicates that it likely achieves 2.0 ppmvd averaged over one hour.

Based on the above information, the District has preliminarily determined that BACT for the CECP combustion turbines is 2.0 ppmvd VOC, measured as methane at 15% O_2, based on a one-hour averaging period for normal operation with appropriate exclusion to address technologically feasibility for startups and shutdowns and other abnormal periods of operation.

The applicant analyzed the use of an oxidation catalyst, which is the only post combustion technology currently available to control CO, VOC, and toxic emissions. An initial source test will be used to confirm compliance with these limits. Additionally, the source test data will be used to establish a correlation between CO emissions and VOC emissions to provide an accurate indicator of continued compliance with these limits using the CEMS data for CO. Compliance will be determined based on both source test data and a surrogate relationship with CO because CEMS technology is not available for VOCs.

Startups and Shutdowns—Combustion Turbines, NOx, CO, and VOCs

Startups are limited to 60 minutes and shutdowns to 30 minutes (an additional 5 minutes are allowed to purge emissions from the stack). These times are consistent with, or more stringent than the recently issued PDOC by the SCAQMD for an identical combined-cycle turbine for the El Segundo Power Redevelopment Project (ESPRP) as recently amended [CEC Docket No. 00-AFC-14C (Amendment Proceeding)]. The expected duration of the turbine startups and shutdowns are 22 minutes and 7 minutes, respectively. The additional time is allowed to address contingencies during startups and shutdowns.

Emissions during startup and shutdown are further controlled by setting mass emission limits per startup and shutdown event (excluding the commissioning period). The mass emission limits are based on manufacturer emission estimates for the expected startup or shutdown durations and maximum emissions during the remainder of the time with an adjustment factor of two for NOx and CO, as proposed by the applicant, to allow for increased emissions during the potential rapid transients during these operations. No adjustment factor is used for VOC emissions, also as proposed by the applicant. For example, for a 60-minute startup, total allowed emissions for NOx are:

Emissions = 2 x (25 lb for the 22 minute startup + (38/60) x 15.1 lbs/hr for normal operations)

= 69.2 lbs

and, for a 30-minute shutdown, total allowed emissions for VOCs are:

Emissions = 5 lb for the 7 minute shutdown + (23/60) x 5.3 lbs/hr for normal operations

= 7 lbs

Table 6a presents the mass emissions limits during startup and shutdown

Table 6a – Emission Limits During Startup and Shutdown – SCR to Operate as Soon as Feasible		
Pollutants	Startup Emissions, pounds per event	Shutdown Emissions, pounds per event
NOx	69.2	25.7
CO	545	277
VOC	16.3	7.0

An additional requirement that applies during startups and shutdowns (and all other times the combustion turbine is operating with an SCR system) is that the SCR be in full operation as soon as its reaches its minimum operating temperature to control NOx to the maximum extent feasible. The minimum temperature is set at 450 degrees Fahrenheit in the proposed permit conditions based on the minimum operating temperature provided by the manufacturer for the similar SCR associated with the ESPRP.

The District has preliminarily determined that the above requirements represent BACT for NOx, CO, and VOCs and LAER, for NOx only, specifically applicable to the CECP during startups and shutdowns of the combustion turbines.

Abnormal Events—Combustion Turbines, NOx, CO, and VOCs

Modern combustion turbines with ultra low NOx combustors normally operate under extremely lean conditions (low fuel to air ratio) where most of the fuel and air are premixed prior to combustion to achieve low NOx, CO, and VOC emissions (lean premix combustion). The operating point is close to the fuel to air ratio where combustion becomes unstable because of the low combustion temperature. To prevent combustion instability, which may result in a turbine trip (unplanned shutdown) and the resulting expense and increased emissions from a unplanned startup, automatic control systems may increase the fuel to air ratio under some abnormal operating conditions. Furthermore, at low loads the fuel may not be premixed with air (diffusion flame mode) to maintain combustion stability. In both these situations, the NOx, CO, VOCs can be much higher than in the lean premix combustion mode. It is, therefore, not technologically feasible, to achieve the BACT emission levels applicable to normal operations in such situations.

Startups and shutdowns are abnormal operating conditions that are discussed above. The applicant has identified transient events (excluding startups and shutdowns) as another abnormal operating condition. Other abnormal operating conditions that, in the District's experience, may occur with large combined-cycle combustion turbines are low-load operation (excluding startups and shutdowns) and tuning of the turbine combustors or emission control systems to achieve the most efficient operation and low emission rates. Low-load operation can occur when the turbine's automatic control system senses a possible combustion or other equipment problem and automatically reduces the turbine load to prevent an immediate turbine trip. In most cases, the problem is resolved without shutting down the turbine, which avoids the emissions and cost of a restart.

Based on information supplied by the applicant and the District's experience with ongoing operations at a large combined-cycle power plant, the District has preliminarily determined that following represent BACT for NOx, CO, and VOCs and LAER for NOx during specified abnormal events:

- Tuning events are not to exceed 720 minutes in a calendar day nor exceed 40 hours in a calendar year for each turbine.

- The BACT emission limits for normal operations with a three-hour-averaging time instead of a one-hour-averaging time are applicable for any hour in which the change in gross electrical output produced by the combustion turbine exceeds 50 MW per minute for one minute or longer.

- Periods of operation at low load are not to exceed 130 minutes in any calendar day nor an aggregate of 780 minutes in any calendar year.

For NOx, emission limits of 12.6 ppmvd averaged and 42 ppmvd averaged over one hour, which correspond to District Rules 69.3.1 and 69.3 standards, respectively, remain in effect during all abnormal periods. The District has proposed amending Rule 69.3.1 to exclude low-load periods. However, if this amendment is adopted, the Rule 69.3 limit would still remain in effect. The District's preliminarily proposed criteria for a transient events and BACT levels have been acceptable to another large combined-cycle facility.

PM10 and SOx—Combustion Turbines

From the ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT for this equipment is the use of natural gas that contains less than 1 grain of sulfur compounds per 100 standard cubic feet of natural gas. Public Utility Commission (PUC) quality natural gas sold in San Diego County is required to meet a maximum sulfur content limit of 0.75 grains of sulfur compounds per 100 standard cubic feet of natural gas. Therefore, use of PUC quality natural gas meeting this 0.75 grains limit is recommended as BACT. In actuality, the natural gas in the local gas distribution system averages well under 0.75 grains per 100 standard cubic feet of gas. The applicant will be required to maintain documents showing the sulfur content of natural gas used. Any alternative supplies of natural gas must meet this sulfur content limit.

BACT—Emergency Fire Pump Engine

When technologically feasible, BACT for emergency engines is to use an engine fueled with natural gas. However, emergency fire pumps require an independent source of fuel for reliable operation in emergency situations in which the natural gas supply might be interrupted. In addition, add-on emission control systems are not technologically feasible as they may compromise the reliability of the fire pump. Therefore, the District has preliminarily concluded that BACT for the emergency fire pump engine is purchase of an engine certified to the most stringent federal emission standard for fire pump engines (i.e., a 2009 or later model year engine). The fire pump engine must also comply with the requirements of Section 93115 et. seq. of Title 17 of the California Codes of Regulations (CCR)

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

This subsection of Rule 20.3 requires that a project resulting in an emission increase equal to or greater than the AQIA Thresholds shall demonstrate through an AQIA that the project will not cause or contribute to a violation of a state or national ambient air quality standard. For the CECP, an Air Quality Impact Analysis (AQIA) was performed to determine if the proposed project by itself contributes to an exceedance of the National Ambient Air Quality Standards or the State Ambient Air Quality Standard. The modeling was done under expected worst-case hourly and annual emission rates during commissioning, startup and shutdown, and normal operations. The analysis shows no violation of any Ambient Air Quality Standard. The analysis can be reviewed in the Appendix A of this determination. The proposed permit conditions contain hourly and annual emission limits that are applicable at all times to ensure that the project will not cause or contribute to a violation of any National Ambient Air Quality Standard or State Ambient Air Quality Standards.

Rule 20.3 (d)(3), (4)-Prevention of Significant Deterioration (PSD)

This subsection requires that a PSD evaluation be performed for any new PSD stationary source (source that has an aggregate potential to emit of one or more air contaminants in amount equal to or greater than the PSD thresholds) and to any PSD modification (contemporaneous emission increase occurring at a modified PSD stationary source equal to or greater than the PSD modification thresholds), for those air contaminants for which the District is classified as attainment or unclassified with respect to a national ambient air quality standard. The Encina Power Plant is an existing PSD stationary source. Therefore, only the PSD modification threshold is applicable to determining whether a PSD evaluation needs to be performed. The applicant has accepted that an annual limit of 72.76 tons per year of NOx emissions to keep the project NOx emissions below the PSD modification threshold. Since the annual limit suffices to avoid the PSD modification threshold and NOx emissions are monitored with the CEMS, no limits on hours of normal operations or startup and shutdown are necessary. As shown in Tables 5b and 5c, the contemporaneous emissions increase for all other pollutants do not exceed the applicable PSD modification thresholds after completion of the project. In addition, for Phase I of the project the applicant has accepted proposed permit limits, as necessary, to limit contemporaneous emission increases to less than all PSD modification thresholds (see Tables 5d and 5e).

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

For any project that is subject to the AQIA requirements of Rule 20.3(d)(2), these provisions require the District to publish a notice of the proposed action in at least one newspaper of general circulation in San Diego County as well as send notices and specified documents to the EPA and ARB. Because the project is not subject to Rule 20.3(d)(3) the additional notification requirements of Rule 20.3(d)(3)(iii) are not applicable. Notice of proposed installation of the CECP will be published in the San Diego Daily Transcript and mailed to EPA and ARB air districts for a 30-day comment period.

Rule 20.3(d)(5)-Emission Offsets

This provision requires that emission offsets be provided for projects that result in a contemporaneous emission increase of any federal nonattainment criteria pollutant or its precursors which exceed new major source or major modification thresholds. The District is a federal nonattainment area only for ozone. Therefore, offsets are potentially only required for NOx and VOC emissions, as ozone precursors. For the CECP, VOC contemporaneous emission increases do not exceed the major modification thresholds and an annual emission limit has been accepted. Therefore, offsets are only required for NOx emissions. The maximum contemporaneous emission increase of NOx is 39.9 tons per year for this project. An offset ratio of 1.2 to 1 is required [Rule 20.3(d)(8)(i)(B)], so a total of 47.88 tons per year of NOx emission offsets will be required. The offsets must be surrendered to the District prior to the initial startup of the equipment for which they are required [Rule 20.1(d)(5)(iii)]. Since the CECP may become operational in two phases, 23.91 tons per year of the offsets are assigned to each combustion turbine and 0.06 tons per year are assigned to the emergency fire pump engine.

For Phase I of the project, the applicant has accepted proposed permit limits on NOx to limit contemporaneous emission increases to a level consistent with the emission offsets provided for a single combustion turbine and the emergency fire pump engine. The offsets assigned to the emergency fire pump engine do not rely on any actual emission reductions at the facility to reduce the engine's contemporaneous emission increase by itself. However, the contemporaneous emission increase for the combustion turbine and the emergency fire pump engine combined are limited to a level consistent with the offsets provided for both emission units.

Offsets may be actual emission reductions, stationary source Class A emission reduction credits (ERCs) issued under District Rules 26.0-26.10, or mobile source emission reduction credits (MERCs) issued under District Rule 27 (if approved by ARB and EPA.). The applicant currently owns Emission Reduction Credits (ERCs) representing 37.6 tons per year of NOx emission offsets and has identified more than 10.3 tons per year of NOx emission offset available for purchase. For the purpose of the PDOC, the District considers this an adequate demonstration that the applicant can obtain sufficient credits.

Rule 20.3(e)(1) – Compliance Certification

This rule requires that prior to receiving an Authority to Construct (or Final Determination of Compliance), an applicant for any new or modified stationary source required to satisfy the LAER provisions of Rule 20.3(d)(1) or the major source offset requirement of Rule 20.3(d)(8) shall certify that all major sources operated by such person in the state are in compliance with all applicable emissions limitations and standards under the federal Clean Air Act. Carlsbad Energy Center, LLC (the applicant) is an indirect wholly owned subsidiary of NRG Energy, Inc., which also operates the Encina Power Station, which is a major stationary source located in San Diego County, and on whose property the CECP will be located. The Encina Power Station operation has been regulated by the San Diego Air Pollution Control District under permits to operate issued for its five boilers and one gas turbine. Besides the Encina Power Station, NGR Energy, Inc., owns other potential major stationary sources in the state, including the El Segundo Generating Station in El Segundo California and the Long Beach Generating Station in Long Beach California. A compliance certification for all major sources in the state owned by NRG Energy, Inc. will be required before the FDOC is issued.

Rule 20.3(e)(2) – Alternative Siting and Alternatives Analysis

The applicant has provided an analysis of various alternatives to the project. This analysis included a No Project alternative, alternative sites, and alternative technologies. Since all of San Diego County is currently classified as non-attainment for ozone, an alternative location within San Diego would not avoid the project being located in a non-attainment area.

Rule 20.5 – Power Plants

This rule requires that the District submit Preliminary and Final Determinations of Compliance reports to the California Energy Commission (CEC). The Final Determination of Compliance is equivalent to a District Authority to Construct. This Preliminary Determination of Compliance is to be submitted to the CEC. The Final Determination of Compliance will be submitted subsequently after a 30-day comment period for the PDOC and after consideration of any comments received.

DISTRICT PROHIBITORY RULES

Rule 50 – Visible Emissions

This rule limits air contaminants emissions into the atmosphere of shade darker than Ringlemann 1 (20% opacity) to not more than an aggregate of three minutes in any consecutive sixty-minute period.

Based on the proposed equipment and the type of fuel to be used (natural gas), no visible emissions at or above this level are expected during operation of the power plant.

Rule 51 – Nuisance

This rule prohibits the discharge of air contaminants that cause or have a tendency to cause injury, nuisance, annoyance to people and/or the public or damage to any business or property.

No nuisance or complaints are expected from this type of equipment.

Rule 53 – Specific Air Contaminants

This rule limits emissions of sulfur compounds (calculated as SO_2) to less than or equal to 0.05% (500 ppm) by volume, on a dry basis. The rule also limits particulate matter emissions from gaseous fuel combustion to less than or equal 0.1 grains per dry standard cubic foot of exhaust calculated at 12% CO_2.

Sulfur Compounds

The applicant proposes to use Public Utilities Commission (PUC) quality natural gas sold in San Diego County. Because of the low sulfur content of the fuel, the plant is expected to comply with the sulfur emission requirements of Rule 53. The fuel is expected to have a sulfur content less than 0.75 grains per 100 dry standard cubic foot (gr/100 dscf).
Using an F-Factor of 8710 standard cubic feet of exhaust gas per million Btu of heat input for natural gas combustion at 0% O_2 in the exhaust, assuming all sulfur in the fuel is converted into SO_2, the concentration by volume of SO_2 in the exhaust gas is:

SO_2 concentration = (0.75 grain /100 scf fuel) x (1lb SO_2 / 7000 grain) x (385 scf SO_2 / 64 lb SO_2) x (1 scf fuel / 1015 x 10^{-6} MMBtu) x (1MMBtu / 8710 dscf of exhaust) x (10^6) = 0.72 ppm SO_2 by volume.

This is well below the Rule 53 limit of 500 ppm SO_2 by volume. Therefore, the project is expected to comply with this rule.

Particulates

Using an F-Factor of 198.025 standard cubic feet of exhaust per pound of natural gas combusted @ 12% CO_2, a maximum natural gas usage of 91,454 lbs /hr, and an estimated maximum particulate matter emission rate of 9.5 lbs/hr, combustion particulate at maximum load are estimated to be:

Grain loading = [(9.5 lbs/hr)(7,000 gr/lb)] / (198.025 scf/lb fuel)(91,454 lbs fuel/hr)) = 0.004 gr/dscf

This is well below the Rule 53 emission limit of 0.1 gr/dscf. Therefore the plant is expected comply with this rule.

Rule 68 –Oxides of Nitrogen from Fuel Burning Equipment

This rule limits NOx emissions from any natural gas fueled combustion equipment to less than 125 ppmvd calculated at 3% oxygen on a dry basis. However, this equipment is subject to the more stringent requirements of Rule 69.3 and Rule 69.3.1 and is exempt from Rule 68.

Rule 69.3-Stationary Gas Turbines – Reasonably Available Control Technology

This rule limits NOx emissions from combustion turbines fueled with natural gas greater than 0.3 MW to 42 ppmvd at 15% oxygen when fired on natural gas. Equipment is exempt from the standards during 120 minute startup and shutdown periods.

As proposed, the combustion turbines for this project will be equipped with dry ultra low NOx combustors and SCR controls for NOx. Proposed permit conditions limit NOx emissions to 2.0 ppmvd during normal operations, which is far below the 42 ppmvd rule standard. Maximum durations of startups have been proposed by the applicant (60 minutes for startup and 30 minutes for shutdown) are shorter than Rule 69.3 requirements. However, commissioning, low-load operation, tuning, and transient periods are still subject to the rule standards. The facility permit will contain conditions to limit emissions below the emissions levels specified in Rule 69.3 (excluding startups and shutdown as defined in Rule 69.3). A CEMS will monitor emissions during combustion turbine operations.

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

This rule limits NOx emissions from combustion turbines greater than 10 MW to 15x(E/25) ppmvd when operating uncontrolled and 9 x (E/25) ppm at 15% oxygen when operating with add-on emission controls and averaged over a one-hour period, where E is the thermal efficiency of the unit. The rule also specifies monitoring and record keeping requirements. Startups, shutdowns, and fuel changes are defined by the rule and excluded from compliance with these limits. Equipment is exempt from the standards during 120 minute startup and shutdown periods. Maximum durations of startups have been proposed by the applicant (60 minutes for startup and 30 minutes for shutdown) are shorter than Rule 69.3.1 requirements.

The thermal efficiency for each turbine, as stated by the applicant, is 36.5 %. Therefore the maximum allowable uncontrolled NOx concentration is 21.9 ppmvd based on a 1-hour averaging period at 15% oxygen and the maximum allowable controlled NOx concentration is 12.6 ppmvd. The uncontrolled concentration limit would only be applicable prior to installation of the SCR system.

As proposed, the combustion turbines for this project will be equipped with dry ultra low NOx combustors and SCR controls for NOx. Proposed permit conditions limit NOx emissions to 2.0 ppmvd during normal operations, which is far below the 12.6 ppmvd rule standard. Maximum durations of startups have been proposed by the applicant (60 minutes for startup and 30 minutes for shutdown) are shorter than Rule 69.3.1 requirements. However, commissioning, low-load operation, tuning, and transient periods are still subject to the rule standards. The facility permit will contain conditions to limit emissions below the emissions levels specified in Rule 69.3.1 (excluding startups and shutdown as defined in Rule 69.3.1). A CEMS will monitor emissions during combustion turbine operations. A CEMS will monitor emissions during combustion turbine operations.

Rule 69.4 – Stationary Reciprocating Internal Combustion Engines – Reasonably Available Control Technology

This rule applies to stationary internal combustion engines with brake horsepower rating of 50 or greater and located at a stationary source with potential to emit of 50 tons per year or more of NOx. Since the proposed emergency fire pump engine is subject to Rule 69.4.1, which contains more stringent standards, compliance with Rule 69.4.1 will serve for compliance with Rule 69.4.

Rule 69.4.1 – Stationary Reciprocating Internal combustion Engines – Best Available Retrofit Control Technologies.

Rule 69.4.1(d)(1) requires the engine to meet the NOx emission standard of 6.9 grams per brake horsepower hour (g/bhp-hr). This preliminarily proposed engine is an EPA certified engine with NOx emission at 3.92 g/bhp-hr. In addition, proposed permit conditions will require the engine to meet the more stringent EPA certification requirements for model year 2009 and later engines. Therefore, the engine is in compliance with this requirement.

Rule 69.4.1(d)(2) requires the engine to meet CO emission standard of 4500 ppmvd at 15% oxygen. This engine is in compliance with this requirement, with a CO emission level of 61.2 ppmvd at 15% oxygen.

Rule 69.4.1(d)(4) requires the engine to use only California Diesel fuel. The use of CARB diesel is specified in the proposed permit conditions.

Rule 69.4.1(e)(3) requires installation of a non-resettable totalizing meter or a non-resettable hour meter. The proposed engine has an hour meter.

Rule 69.4.1 requires the engine operator to conduct periodic maintenance of the engine and its control system in accordance with a procedure recommended by the manufacturer or approved by the District. Compliance with this requirement is verified through recordkeeping.

Rule 69.4.1(g)(1)(v), (vi) requires the engine operator to keep records of California Diesel fuel certification and engine maintenance procedure. Compliance with this requirement is verified through recordkeeping.

Rule 69.4.1(g)(2) requires the engine operator to maintain an operating log of the dates and times of engine operation, of the total cumulative hours of operation per calendar year, and of engine periodic maintenance. Compliance with this requirement is verified through recordkeeping.

Rule 69.4.1(g)(6) requires all records to be kept on site for at least three years and made available to the District upon request. The proposed permit conditions require records to be kept five years.

Rule 69.4.1(i)(1) exempts emergency standby engines from periodic source testing.

Rule 1200 – Toxic Air Contaminants

Rule 1200 New Source Review for Toxic Air Contaminants requires that a Health Risk Assessment (HRA) be performed if the emissions of toxic air contaminants will increase. A detailed HRA is necessary if toxics emissions exceed District de minimis levels. Toxic Best Available Control Technology (TBACT) must be installed if the HRA shows a cancer risk greater than one in a million. Additional requirements apply if the cancer risk is expected to exceed ten in a million.

An HRA was performed using EPA AP-42 emission factors and California Air Toxics Emission Factors (CATEF) for toxic air contaminant emissions from the project, which include the two combustion turbines and the emergency fire pump engine. The health risk was determined to be less than one in a million at all the receptors located beyond the plant boundary. In addition, a supplementary HRA was performed using emission factors based on a recent source test of a combined-cycle power plant during the first hour of a cold start. These emission factors were used to further examine acute, chronic, and cancer health risks during startup and commissioning operations. The HRA performed shows that the cancer risk is less than one in a million if the number of startups per turbine is limited to 1460 per year. Proposed permit conditions limit the number of startups for each turbine to 1460 per year, so TBACT is not required. The acute and chronic health risks also meet Rule 1200 requirements. Although TBACT is not required for this project, the oxidation catalyst installed as BACT for CO and VOC emissions will also significantly reduce toxic air contaminant emissions. The heath risk analysis of this project is discussed in Appendix B of this document.

Regulation XIV – Title V Operating Permits

The CECP is co-located with the Encina Power Station and under common control ownership. The Encina Power Station currently has a Title V Operating Permit. The applicant has submitted an application to modify this Title V Operating Permit to include the CECP project.

STATE REGULATIONS IMPLEMENTED BY THE DISTRICT

Health and Safety Code §42301.6

This section of the state Health and Safety Code requires the District to notify parents of students at a school if a new source of air pollution is within a 1000 feet of the boundary of that school. The District has determined that the CECP is not within 1000 feet of any school boundary.

Title 17 of the California Codes of Regulations (CCR) §93115—Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines

The emergency diesel fire pump engine is subject to the Title 17 of the California Codes of Regulations (CCR) §93115—Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines.

Section 93115.5(a)(1) requires that by January 1, 2006, no owner or operator of a new stationary CI engine or an in-use prime stationary diesel-fueled CI engine shall fuel the engine with any fuel unless the fuel is one of the following: CARB Diesel Fuel; or an alternative diesel fuel that meets the requirements of the Verification Procedure; or an alternative fuel; or CARB Diesel Fuel used with fuel additives that meets the requirements of the Verification Procedure; or any combination of the above fuels. The proposed permit conditions required the use of only CARB Diesel Fuel.

Section 93115.6(a)(1) requires that no owner or operator shall operate a new stationary emergency standby diesel-fueled CI engine for nonemergency use, including maintenance and testing, during the following periods: whenever there is a school sponsored activity, if the engine is located on school grounds; and between 7:30 am and 3:30 pm on days when school is in session if the engine is located within 500 feet of school grounds. This requirement does not apply if the engine emits no more than 0.01 g/bhp-hr of diesel PM. Compliance is required through proposed permit conditions.

Section 93115.6(a)(3)(A)(1) requires that new stationary emergency standby diesel-fueled engines (>50 bhp) shall emit diesel PM at a rate less than or equal to 0.15 g/bhp-hr; or meet the current model year PM standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423), whichever is more stringent; and not operate more than 50 hours per year for maintenance and testing purposes. The proposed engine PM emission rate is 0.09 g/bhp-hr. The engine is limited to 50 hours per year for testing and maintenance operation by proposed permit conditions.

Section 93115.6(a)(3)(B) requires that new stationary emergency standby diesel-fueled engines (>50 bhp) meet the HC, NOx, NMHC+NOx, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13, CCR, Section 2423). The preliminarily proposed engine meets the Tier 2 HC, NOx, NMHC + NOx and CO standards for off-road engine of the 2005 model year.

Section 93115.10(a) requires each owner or operator of new and in-use stationary CI engines, including non-diesel-fueled CI engines, to submit to the District APCO information on owner/operator contact information; engine information; fuel used; operation information; receptor information; and whether the engine is included in an existing AB2588 emission inventory. The District may exempt the owner or operator from providing all or part of this information if there is a current record of the information in the owner or operator's permit to operate, permit application, or District records. This information has been provided by the applicant in the application submitted for the CECP.

Section 93115.10(e) requires that a non-resettable hour meter be installed upon engine at installation on all engines subject to all or part of the emission standards requirements. The engine will be required to have an hour meter by the proposed permit conditions.

Section 93115.10(g)(1) requires each owner or operator of an emergency standby diesel-fueled CI engine to keep records and prepare a monthly summary that lists and documents the nature of use for emergency use hours, maintenance and testing hours, initial start-up testing hours, retention of fuel purchase records for CARB diesel fuel. Compliance is required through proposed permit conditions.

Section 93115.10(g)(2) requires all records to be retained for a minimum of 36 months. Records for the prior 24 months shall be retained on-site, and made immediately available to District staff upon request. Records for the prior 25 to 36 months shall be made available to District staff within 5 working days from request. Compliance is required through proposed permit conditions.

Section 93115.13 requires that upon approval by the District APCO, the following sources of data may be used in whole or in part to meet the emission data requirements:

A. Off road engine certification test data for the stationary diesel-fueled CI engine.
B. Engine manufacturer test data.
C. Emission test data from a similar engine, or
D. Emission test data used in meeting the requirements of the Verification Procedure for the emission control strategy implemented.

Engine manufacturer emission data were used to verify compliance with emission standard requirements.

NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)

The Encina Power Station is an existing major source of hazardous air pollutants (HAPs) based on the potential to emit hexane over the 10 ton per year major source threshold for a single HAP. Estimated actual emissions of hexane, calculated using an EPA (AP-42) emission factor, were about 13.5 tons per year in 2006. Therefore, equipment at the Encina Power Station are subject to NESHAPS applicable to major stationary sources of HAPs.

40 CFR Part 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

This subpart establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emissions and operating limitations. However, except for Initial Notification requirements [40 CFR §63.6145] EPA has stayed the applicability of this regulation for gas-fired combustion turbines [40 CFR §63.6905(d)].

40 CFR Part 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Compression Ignition Internal Combustion Engines

This subpart for stationary compression ignition internal combustion engines requires [40 CFR §63.6590(c)] engines rated less than 500 brake horsepower located at major sources of HAP emissions (and also all engines at nonmajor sources of HAPs) to comply with the requirements in 40 CFR Part 60 Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion (CIIC) Engines. There are no other requirements applicable to such engines. Proposed permit conditions require compliance with Subpart IIII.

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR Part 60- Subpart KKKK- National Standards of Performance for New Stationary Combustion Turbines.

This new source performance standard requires stationary combustion turbines with a heat input equal to or greater than 10 MMBtu/hour based on the high heating value of the fuel to comply with NOx and SOx emission standards.

Section 60.4320 requires new combined-cycle combustion turbines firing natural gas with a rated heat input greater than 850 MMBtu/hour to comply with a NOx standard of 15 ppmvd at 15% O_2 averaged over each 30 operating days, or alternatively, a standard of 0.42 pounds per megawatt hour (lb/MWh) during normal operations. During periods of less than 75% load the corresponding standards are 96 ppmvd and 4.7 lb/MWh. The actual limit during any 30-day period is an average of the normal and less than 75% standards.

With SCR as post-combustion emission control, NOx emissions from this combustion turbine are controlled to 2 ppm at 15% O_2 during normal operation. Information submitted as part of the proposed City of Vernon Power Plant (06-AFC-4, Table 8.1B-2) indicates that the expected typical maximum NOx level for this model turbine is 50 ppm at less than 50% load (as occurs during startup and shutdown. Assuming NOx emission concentration during startup and shut down is 50 ppm at 15% O_2, the NOx emission concentration averaged over a 30-day period that has 50 hours of startup, 25 hours of shutdown and 250 hours of normal operation is:

NOx concentration = [50 ppm x (50 startup hours)] x [50 ppm x (25 shutdown hours)] + (2 ppm x 250 normal operation hours)] / (325 hours) = 13 ppm

Therefore, the turbine is expected to comply with the NOx emission standard of this subpart. Compliance is required through proposed permit conditions.

Section 60.4330 prohibits sulfur dioxide emissions from combustion turbine in excess of 0.90 lbs/MW-hour gross output or 0.060 lbs/MMBtu heat input. SO_2 emission from the combustion turbines of this project is 0.002 lbs/MMBtu.

SO_2 emission rates = (4.4 lbs/hr) x (1 hour/ 1947 MMBtu) = 0.002 lbs/MMBtu

Therefore, the turbine is in compliance with the SO_2 limit requirement.

Section 60.4340(b) requires turbines not using water injection or steam injection to install, calibrate, maintain and operate a continuous emission monitoring system (CEMS) consisting of a NOx monitor and a diluent gas (oxygen) or carbon dioxide monitor to determine the hourly NOx emission rate in ppmvd or lb/MWh. Turbines complying with concentration limit based standards must install calibrate, maintain and operate a fuel flow meter to measure heat input. Turbines complying with output-based standards must install, calibrate, maintain and operate a watt meter to measure the gross electrical output in megawatt-hours. This combustion turbine will be equipped with a CEMS to monitor NOx and CO emissions in parts per million and oxygen content in the exhaust gas. In addition, the gross electrical output in MWh will also be monitored.

Section 60.4345 requires the CEMS to be installed and certified according to Performance Specification 2 in Appendix B to this part, or according to Appendix A of part 75 of this chapter, and each fuel meter and watt meter shall be installed, calibrated, maintained and operated according to the manufacturer's instructions. The turbine operator must develop and keep on site a QA plan for all continuous monitoring equipment. The CEMS for this combustion turbine will be required to go through Relative Accuracy Test Audit (RATA) and all other required certification tests in accordance with 40 CFR Part 75 Appendix A and B. The proposed permit requires continuous monitoring equipment meeting these requirements to be installed, calibrated, and maintained.

Section 60.4350 requires turbine operator to use data from the CEMS to identify excess emissions in accordance with specific procedures. These requirements are included in the proposed permit conditions.

Section 60.4365 exempts the requirement to monitor total sulfur content of the fuel if it can be demonstrated through a valid purchase contract , tariff sheet or transportation contract for the fuel that total sulfur content of natural gas used is 20 grains of sulfur or less per 100 standard cubic feet. Sulfur content of natural gas fuel used in this turbine is 0.75 grains per 100 cubic feet of gas or less. Quarterly records of natural gas sulfur content are to be kept on site to satisfy this requirement.

Section 60.4375 requires submittal of reports of excess emissions and monitor downtime for all periods of unit operation, including startup, shutdown and malfunction. The proposed permit includes a condition to satisfy these requirements. Annual source tests are not required pursuant to Subpart KKKK for combustion turbine equipment with CEMS. Since this combustion turbine is subject to a NOx limit that is seven times more stringent than the NOx limit of this NSPS, excess emissions are not expected to occur. In addition, reports on the CEMS system are to be submitted in accordance with Rule 19.2 requirements and CEMS protocol approved by the District and excess emissions and monitoring reports are required by the proposed permit conditions..

Section 60.4400 requires that an initial performance test and annual NOx performance test be conducted in accordance with certain requirements. Annual source tests are not required pursuant to Subpart KKKK for combustion turbine equipment with CEMS. This combustion turbine is required to be source tested initially to demonstrate compliance with NOx, CO, VOC, and ammonia emission standards. The source tests are to be conducted in accordance with the applicable EPA test methods and applicable requirements of 40 CFR 75 Appendix B. The proposed permit contains conditions satisfying these requirements of Subpart KKKK.

40 CFR Part 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion (CIIC) Engines

Section 60.4205 requires owners and operators of fire pump engines rated between 175 bhp and 300 bhp and of model year 2008 and earlier to comply with NOx + HC emission limit of 7.8 grams per brake horsepower hour (g/bhp-hr), CO limit of 2.6 g/bhp-hr and a PM limit of 0.4 g/bhp-hr. Fire pump engines of model year 2009 and after must comply with NOx + HC emission limit of 3 g/bhp and PM emission limit of 0.15 g/bhp-hr. Although the engine preliminarily proposed by the applicant would not comply with model year 2009 standards, the applicant has committed to purchase of a compliant engine and the proposed permit conditions require compliance with the standards of Subpart IIII for model year 2009 and later engines.

Section 60.4207 requires that beginning October 1, 2007, owners and operators of station CIIC engines subject to Subpart IIII to use diesel fuel with a maximum sulfur content of 500 ppm per gallon; and beginning October 1, 2010, to use diesel fuel with a maximum fuel content of 15 ppm per gallon. This engine is required to use CARB diesel fuel, which complies with this requirement.

Section 60.4209 requires that owners or operators of engines subject to Subpart IIII to install a non-resettable hour meter prior to startup of the engine. This requirement is included in the proposed permit conditions.

Section 60.4214 states that owner of engines that are stationary emergency standby engines are not required to submit an initial notification

ACID RAIN

40CFR Part 72- Subpart A – Acid Rain Program

This part establishes general provisions and operating permit program requirements for sources and units affected under the Acid Rain program, pursuant to Title IV of the Clean Air Act. The combustion turbines of this project are affected by this Acid Rain Program as a utility unit in accordance with Section 72.6(a).

40CFR Part 72- Subpart C – Acid Rain Permit Applications

This subpart requires any source with an affected unit to submit a complete Acid Rain permit application by the applicable deadline. Requirement for submittal of Acid Rain Program application will be included in the proposed Authority to Construct for the combustion turbines of this project.

40CFR Part 73- Sulfur Dioxide Allowance System

This part establishes the requirements and procedures for the allocation of sulfur dioxide emission allowances; the tracking, holding and transfer of allowances; the deduction of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to Parts 72; the sale of allowances through EPA-sponsored auctions and a direct sale; the application for allowances from the Conservation and Renewable Energy Reserve; and the application for allowances for desulfurization of fuel by small diesel refineries. Requirements from this part will be included in evaluation for the Acid Rain program application required by Part 72. The proposed permit requires compliance with this requirement.

40CFR Part 75 – Continuous Emission Monitoring

This part established requirements for the monitoring, recordkeeping, and reporting of SO2, NOx, and CO2 emissions, volumetric flow, and opacity data from emission units under the Acid Rain Program. The regulations include general requirements for the installation, certification, operation, and maintenance of continuous emission or opacity monitoring systems, certification tests and procedures, and quality assurance tests and procedures. Subpart B on Monitoring Provisions established general operating requirements for the monitoring systems. Subpart C establishes requirements on initial certification and recertification procedures. Subparts F and G establish requirements on recordkeeping and reporting requirements. All applicable requirements are included in the Authority to Construct conditions.

VI. ADDITIONAL ISSUES

Particulate Emission Relating to the Use of Reclaimed Water for Evaporative Cooling

The proposed Siemens turbines have inlet air filters located upstream of the evaporative coolers. The evaporative cooler is turned on only during normal operation when ambient temperature is higher than 60°F. The particulate emission factor of 9.5 lbs/hr provided by the turbine vendor includes anticipated particulate matter from the evaporative cooler parameters. Therefore, no further particulate emissions from the evaporative cooler are included in the emission calculation.

Commissioning Period

After construction of the equipment has been completed, the applicant will be allowed a commissioning period of 120 days or 415 operating hours for each turbine, whichever comes sooner. During the 120-day commissioning period, the turbines will go through testing and tuning to ensure that the equipment is working properly and will be able to comply with all the proposed emission limits. However, during the initial startup, certain emissions standards must remain in effect. These include the 72.76 tons/yr limit for NOx, hourly mass emission limits for NOx and CO to ensure there will be no violation of any state or national ambient air quality standards, and the hourly concentration limits for NOx to ensure compliance with the District RACT and BARCT Rules 69.3 and 69.3.1, respectively. A CEMS will be required to be installed at the time of initial startup to monitor emissions during the commissioning period from each turbine.

Once the emissions control equipment has been installed and is in good working order, the turbines must meet all BACT/LAER standards and permit requirements. CEMS and source testing will be used to show compliance with these standards.

VII. CONCLUSIONS AND RECOMMENDATIONS

A Determination of Compliance confers the same rights and privileges as an Authority to Construct only when and if the California Energy Commission (CEC) approves the Application For Certification, and the CEC certificate includes all conditions of the Determination of Compliance as proposed by the Air Pollution Control Officer.

If operated in accordance with the conditions specified in this Preliminary Determination of Compliance, this equipment is expected to operate in compliance with all Rules and Regulations of the San Diego County Air Pollution Control District.

Originally Signed by Camquin Nguyen 11/21/08

Project Engineer Date

Originally Signed by Steven Moore 11-21-08

Senior Engineer Approval Date

APPENDIX A

APPROVAL OF AIR QUALITY IMPACT ANALYSIS

AIR QUALITY IMPACT ANALYSIS

FINAL REVIEW REPORT

CARLSBAD ENERGY CENTER PROJECT
APPLICATION 985423

SEPTEMBER 24, 2008

Prepared For
Mechanical Engineering
San Diego Air Pollution Control District
10124 Old Grove Road
San Diego, California 92131

Prepared By
Ralph DeSiena
Monitoring and Technical Services
San Diego Air Pollution Control District
10124 Old Grove Road
San Diego, California 92131

1.0 INTRODUCTION

An Air Quality Impact Analysis (AQIA) was performed for the Carlsbad Energy Center Project (CECP) by Sierra Research of Sacramento, CA. This report focuses on Section 5.1 of the AFC and the AQIA analysis results provided in the original (September, 2007) and subsequent modeling analysis performed (May 13, 2008).

2.0 PROJECT DESCRIPTION

NRG Energy, Inc. is proposing to remove three existing boilers at the Encina Power Station (Units 1, 2 and 3) and install two new Siemens Rapid Response SGT6-5000F Combined Cycle (R2C2) combustion turbine generators (CTGs). The gas turbines will be equipped with steam power augmentation and evaporative cooling. Each gas turbine is followed by a heat recovery steam generator (HRSG) and condensing steam turbine generator. The two units will provide a total nominal generating capacity of 558 MW net.

3.0 AIR QUALITY IMPACT ANALYSIS

Dispersion modeling was conducted for Normal, Startup/Shutdown and Commissioning period emissions of NO_2, CO, SO_2 and PM_{10} and $PM_{2.5}$. The applicant and their consultant (Sierra Research) worked closely with the District in developing modeling and analysis procedures in support of demonstrating compliance with all applicable NSR requirements. Modeling was performed in order to determine whether emissions during these time periods would impact the State and/or Federal Ambient Air Quality Standards for all criteria pollutants.

The modeling procedures are discussed in the following subsections.

3.1 MODELING METHODOLOGIES

AERMOD was used first to "screen" the different turbine stack emission and ambient temperature parameters for the conditions that generate the highest ground-level concentrations of criteria pollutants. Gas turbine specifications were developed and modeled for four temperature scenarios: extreme hot temperature (104 F), summer average temperature (74 F), annual average temperature (61 F) and extreme low temperature (37 F). Stack parameters and criteria pollutant emission rates were provided at each of these three ambient temperatures. Similarly, stack parameters and emission rates were provided at each ambient temperature for the turbines running at 100%, 75%, 60% and 50% load. The stack parameters and maximum emission rates for the screening modeling are presented in Table 3-1 and the maximum predicted screening model impacts are shown in Table 3-2.

After screening modeling, refined modeling was performed using EPA's AERMOD (Version 06341) model with the "maximum impact" turbine stack conditions and emission rates to determine the maximum criteria pollutant concentrations for the appropriate averaging periods for each criteria pollutant. Table 3-3 shows the inputs for the refined modeling.

Startup/Shutdown and Commissioning modeling for the elevated emission rates of NOx and CO existing during these conditions was also performed. The model inputs used to simulate those conditions are provided in Table 3-4.

Additionally, the EPA's SCREEN3 (Version 96043) model is used to determine the potential impacts if the project emissions are subjected to fumigation from breakup of the overnight inversion that can form. This special case is modeled as an extra precaution to avoid an exceedance of ambient air quality standards under these special atmospheric conditions.

All modeling was performed in accordance with EPA guidance and District standard procedures. Regulatory default settings were used. The receptor grid was sufficiently dense to identify maximum impacts.

3.2 METEOROLOGICAL DATA USED FOR DISPERSION MODELING

Meteorological data used for EPA's Aermod Prime model consisted of the following data for the 2003 through 2005 time period. The data was processed by the District using EPA's Aermet meteorological data processor (Version 06341) to produce Aermod ready files.

- Wind speed, wind direction, standard deviation of the horizontal wind direction and temperature from the District's Camp Pendleton monitoring station.

- Twice-daily upper-air soundings from Miramar Marine Corps Air Station, San Diego, CA.

- Cloud height and total opaque cloud amount from Palomar Airport, Carlsbad, CA.

- Wind speed, wind direction and temperature data from Palomar Airport, Carlsbad, CA for replacement of missing data in the Camp Pendleton data set.

- Wind speed, wind direction and temperature data with height from the District's wind profiler with RASS located near the Miramar Marine Corps Air Station, San Diego, CA.

Table 3-2
Screening Level Modeling Impacts

Table 5.1D-3 (Revised 6/11/08)
Screening Level Modeling Impacts
(Combined Impacts for Two Gas Turbines)

Operating Mode	NO2 1-hr	CO 1-hr	SO2 1-hr	SO2 3-hr	CO 8-hr	PM10 24-hr	SO2 24-hr	NO2 Annual	PM10 Annual	SO2 Annual
Avg. Peak	14.667	8.930	4.262	1.944	1.871	0.888	0.408	0.122	0.077	0.035
Avg. Base (cooler)	14.231	8.665	4.135	1.888	1.795	0.922	0.398	0.124	0.083	0.036
Avg. Base	13.268	8.078	3.855	1.872	1.775	0.935	0.395	0.125	0.086	0.036
Avg. Mid.	13.963	8.502	4.057	1.719	1.674	1.084	0.372	0.129	0.109	0.038
Avg. Low (60%)	13.265	8.077	3.854	1.780	1.604	1.175	0.352	0.129	0.125	0.037
Hot Peak	14.483	8.818	4.208	1.921	1.847	0.899	0.406	0.123	0.079	0.036
Hot Base (cooler)	14.032	8.543	4.077	1.839	1.758	0.917	0.389	0.120	0.082	0.035
Hot Base	13.527	8.236	3.930	1.788	1.685	0.996	0.381	0.127	0.096	0.037
Hot Mid.	13.046	7.943	3.791	1.731	1.633	1.151	0.360	0.130	0.121	0.038
Hot Low (60%)	12.062	7.344	3.505	1.797	1.566	1.238	0.340	0.129	0.137	0.038
Mild Base (cooler)	14.216	8.655	4.130	1.889	1.818	0.901	0.400	0.121	0.079	0.035
Mild Base	13.960	8.500	4.056	1.883	1.804	0.908	0.398	0.122	0.081	0.035
Mild Mid.	12.765	7.772	3.709	1.740	1.654	1.051	0.374	0.128	0.104	0.037
Mild Low (60%)	12.673	7.716	3.682	1.661	1.610	1.148	0.355	0.128	0.120	0.037
Cold Base	13.159	8.012	3.823	1.932	1.866	0.869	0.402	0.118	0.074	0.034
Cold Mid.	13.163	8.014	3.824	1.759	1.662	1.005	0.376	0.126	0.098	0.037
Cold Low (60%)	13.071	7.958	3.798	1.648	1.621	1.104	0.359	0.126	0.113	0.037

Table 3-3
Emission Rates and Stack Parameters for Refined Modeling

Table 5.1D-4A (Revised 5/11/08)
Emission Rates and Stack Parameters for Refined Modeling

	Stack Diam, m	Stack Height, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10	Stack Diam, ft	Stack Height, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	Emission Rates, lb/hr NOx	SO2	CO	PM10
Averaging Period: One hour NOx																		
Unit 6	6.5	42.4	456	688.5	20.8	1.8931	n/a	n/a	n/a	21.3	139	361	1,458,766	68	15.02	n/a	n/a	n/a
Unit 7	6.5	42.4	456	688.5	20.8	1.8931	n/a	n/a	n/a	21.3	139	361	1,458,766	68	15.02	n/a	n/a	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	0.2620	n/a	n/a	n/a	0.33	30	938	1,328	254	2.08	n/a	n/a	n/a
Averaging Period: One hour CO and SOx																		
Unit 6	6.5	42.4	456	688.5	20.8	n/a	0.5500	1.1526	n/a	21.3	139	361	1,458,766	68	n/a	4.37	9.15	n/a
Unit 7	6.5	42.4	456	688.5	20.8	n/a	0.5500	1.1526	n/a	21.3	139	361	1,458,766	68	n/a	4.37	9.15	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	0.0003	0.0305	n/a	0.33	30	938	1,328	254	n/a	0.00	0.24	n/a
Averaging Period: Three hours SOx																		
Unit 6	6.5	42.4	456	688.5	20.8	n/a	0.5500	n/a	n/a	21.3	139	361	1,458,766	68	n/a	4.37	n/a	n/a
Unit 7	6.5	42.4	456	688.5	20.8	n/a	0.5500	n/a	n/a	21.3	139	361	1,458,766	68	n/a	4.37	n/a	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	0.0001	n/a	n/a	0.33	30	938	1,328	254	n/a	0.00	n/a	n/a

Table 3-3 *(Continued)*
Emission Rates and Stack Parameters for Refined Modeling

Table 5.1D-4B (Revised 5/11/08)
Emission Rates and Stack Parameters for Refined Modeling (cont.)

	Stack Diam, m	Stack Height, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10	Stack Diam, ft	Stack Height, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	Emission Rates, lb/hr NOx	SO2	CO	PM10
Averaging Period: Eight hours CO																		
Unit 6	6.5	42.4	456	688.5	20.8	n/a	n/a	1.1526	n/a	21.3	139	361	1,458,766	68	n/a	n/a	9.15	n/a
Unit 7	6.5	42.4	456	688.5	20.8	n/a	n/a	1.1526	n/a	21.3	139	361	1,458,766	68	n/a	n/a	9.15	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	n/a	0.0038	n/a	0.33	30	938	1328	254	n/a	n/a	0.03	n/a
Averaging Period: 24-hour SOx																		
Unit 6	6.5	42.4	456	688.5	20.8	n/a	0.5500	n/a	n/a	21.3	139	361	1,458,766	68	n/a	4.37	n/a	n/a
Unit 7	6.5	42.4	456	688.5	20.8	n/a	0.5500	n/a	n/a	21.3	139	361	1,458,766	68	n/a	4.37	n/a	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	0.0000	n/a	n/a	0.33	30	938	1,328	254	n/a	0.00	n/a	n/a
Averaging Period: 24-hour PM10																		
Unit 6	6.5	42.4	439	430.5	13.0	n/a	n/a	n/a	1.1970	21.3	139	331	912,246	43	n/a	n/a	n/a	9.50
Unit 7	6.5	42.4	439	430.5	13.0	n/a	n/a	n/a	1.1970	21.3	139	331	912,246	43	n/a	n/a	n/a	9.50
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	n/a	n/a	0.0002	0.33	30	938	1,328	254	n/a	n/a	n/a	0.00

Table 3-3 *(Continued)*
Emission Rates and Stack Parameters for Refined Modeling

Table 5.1D-4C (Revised 5/11/08)
Emission Rates and Stack Parameters for Refined Modeling (cont.)

						Emission Rates, g/s									Emission Rates, lb/hr			
	Stack Diam, m	Stack Height, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	NOx	SO2	CO	PM10	Stack Diam, ft	Stack Height, ft	Exh Temp, Deg F	Exh Flow Rate, ft3/m	Exhaust Velocity, ft/s	NOx	SO2	CO	PM10
Averaging Period: Annual NOx and SOx																		
Unit 6	6.5	42.4	442	483.9	14.6	1.0865	0.0807	n/a	n/a	21.3	139	336	1,026,286	48	8.62	0.64	n/a	n/a
Unit 7	6.5	42.4	442	483.9	14.6	1.0865	0.0807	n/a	n/a	21.3	139	336	1,026,286	48	8.62	0.64	n/a	n/a
Firepump Engine	0.1	9.1	776	0.6	77.3	0.0015	0.0000	n/a	n/a	0.33	30	938	1,328	254	0.01	0.00	n/a	n/a
Averaging Period: Annual PM10																		
Unit 6	6.5	42.4	439	430.5	13.0	n/a	n/a	n/a	0.5602	21.3	139	331	912,246	43	n/a	n/a	n/a	4.45
Unit 7	6.5	42.4	439	430.5	13.0	n/a	n/a	n/a	0.5602	21.3	139	331	912,246	43	n/a	n/a	n/a	4.45
Firepump Engine	0.1	9.1	776	0.6	77.3	n/a	n/a	n/a	0.0000	0.33	30	938	1,328	254	n/a	n/a	n/a	0.00

Table 3-4
Startup/Shutdown and Commissioning Modeling Inputs

Table 5.1D-6 (Revised 5/11/08)
Startup/Shutdown and Commissioning Modeling Inputs

Operating Case	Amb Temp deg F	Stack height feet	Stack Height meters	Stack Diam feet	Stack Diam meters	Stack flow wacfm	Stack flow m3/sec	Stack Vel ft/sec	Stack Vel m/sec	Stack Temp deg F	Stack Temp deg K
Startup/Shutdown											
Unit 6 - Startup/Shutdown	104	139	42.37	21.3	6.49	858,818	405.37	40.17	12.24	346.00	447.59
Unit 7 - Startup/Shutdown	104	139	42.37	21.3	6.49	858,818	405.37	40.17	12.24	346.00	447.59
Commissioning											
One Unit in Commissioning	104	139	42.37	21.3	6.49	858,818	405.37	40.17	12.24	346.00	447.59
One Unit in Startup/Shutdown	104	139	42.37	21.3	6.49	858,818	405.37	40.17	12.24	346.00	447.59

	NOx lb/hr	CO lb/hr	NOx g/sec	CO g/sec
Startup/Shutdown				
Unit 6 - Startup/Shutdown	85.64	813.52	10.79	102.50
Unit 7 - Startup/Shutdown	85.64	813.52	10.79	102.50
Commissioning				
One Unit in Commissioning	200.13	3812.63	25.22	480.39
One Unit in Startup/Shutdown	85.64	813.52	10.79	102.50

4.0 AIR QUALITY IMPACT ANALYSIS RESULTS

In accordance with EPA and San Diego Air Pollution Control District New Source Review Guidance and the modeling methodologies described above, maximum predicted concentrations associated with facility operations were determined for each of the required criteria pollutant and the applicable averaging period during Normal, Startup/Shutdown and Commissioning conditions. The maximum predicted concentrations occurring during any of the operating conditions modeled were added to worst-case background concentrations for comparison to Federal and State Ambient Air Quality Standards. Worst case background concentrations were determined from the review of 3 years (2004-2006) of monitoring data taken from the District's Camp Pendleton, Escondido or San Diego monitoring stations, whichever was available for a specific criteria pollutant and deemed to be most representative of air quality in the facility area. Table 4-1 summarizes the worst case background concentrations.

The maximum ground-level impacts at any location from normal operations, startup/shutdowns and the special circumstances of inversion breakup fumigation are given in Table 4-2.

Table 4-3 provides the summary of project modeled maximum impacts for Commissioning period operating conditions.

Table 4-4 provides the summary of the proposed project modeled maximum impacts, including worst case ambient background concentrations, compared with Federal and California Ambient Air Quality Standards (AAQS).

Table 4-5 provides a comparison of maximum modeled impacts during normal operation and PSD significant impact levels.

TABLE 4-1
MAXIMUM BACKGROUND CONCENTRATIONS[a], PROJECT AREA, 2004-2006 ($\mu g/m^3$)

Pollutant	Averaging Time	2004	2005	2006
NO_2 (Camp Pendleton)	1-hour	**185.9**	144.6	152.1
	Annual	**22.5**	22.5	20.7
SO_2 (San Diego)	1-hour	**110.0**	94.3	89.1
	3-hour	52.4	68.1	**78.6**
	24-hour	**23.6**	23.6	23.5
	Annual	**10.5**	7.9	10.5
CO (Escondido)	1-hour	**6,300**	5,900	5,700
	8-hour	**3,800**	3,100	3,600
PM_{10} (Escondido)	24-hour	**58**	42	52
	Annual	**27**	24	24
$PM_{2.5}$ (Escondido)	24-hour[b]	37	32	28
	Annual	**14.1**	12.3	11.5

Source: California Air Quality Data, California Air Resources Board website; EPA AIRData website. Reported values have been rounded to the nearest tenth of a $\mu g/m^3$ except for PM_{10} which were already rounded to the nearest integer.

Notes:

a. With the exception of 24-hr $PM_{2.5}$, bolded values are the highest during the three years and are used to represent background concentrations.

b. 24-hour average $PM_{2.5}$ concentrations shown are 98th percentile values rather than highest values because compliance with the ambient air quality standards is based on 98th percentile readings. Since the ambient standard is based on a 3-year average of the 98th percentile readings, the 3-year average of the 2004 to 2006 98th percentile readings was used to represent the background concentration.

TABLE 4-2

NORMAL OPERATION AIR QUALITY MODELING RESULTS FOR NEW EQUIPMENT

Pollutant	Averaging Time	Modeled Maximum Concentrations ($\mu g/m^3$) Normal Operations AERMOD	Startup/Shutdown AERMOD	Fumigation SCREEN3	Shoreline Fumigation SCREEN3
		Combined Impacts Both CTGs			
NO_2	1-hour	13.3	80.4	2.6	18.5
	Annual	0.1	a	c	c
SO_2	1-hour	4.3	b	0.8	5.4
	3-hour	2.0	b	0.6	4.8
	24-hour	0.4	b	0.3	0.5
	Annual	0.0	b	c	c
CO	1-hour	9.0	1133.8	1.6	11.3
	8-hour	1.9	236.0	1.0	3.5
$PM_{2.5}/PM_{10}$	24-hour	1.2	b	0.9	1.7
	Annual	0.1	b	c	c
		Fire pump Engine			
NO_2	1-hour	108.0	d	e	e
	Annual	0.1	d	e	e
SO_2	1-hour	0.2	d	e	e
	3-hour	0.0	d	e	e
	24-hour	0.0	d	e	e
	Annual	0.0	d	e	e
CO	1-hour	18.2	d	e	e
	8-hour	1.0	d	e	e
$PM_{2.5}/PM_{10}$	24-hour	0.0	d	e	e
	Annual	0.0	d	e	e
		Combined Impacts New Equipment			
NO_2	1-hour	108.0	f	f	f
	Annual	0.1	f	f	f
SO_2	1-hour	4.3	f	f	f
	3-hour	2.0	f	f	f
	24-hour	0.4	f	f	f
	Annual	0.0	f	f	f
CO	1-hour	18.2	f	f	f
	8-hour	1.9	f	f	f
$PM_{2.5}/PM_{10}$	24-hour	1.2	f	f	f
	Annual	0.1	f	f	f

a. Not applicable, because startup/shutdown emissions are included in the modeling for annual average.

b. Not applicable, because emissions are not elevated above normal operation levels during startups/shutdowns.

c. Not applicable, because inversion breakup is a short-term phenomenon and as such is evaluated only for short-term averaging periods.

d. Not applicable, because engine will not operate during CTG startups/shutdowns.

e. Not applicable, this type of modeling is not performed for small combustion sources with relatively short stacks.

f. Impacts are the same as shown for CTGs.

TABLE 4-3

MODELED IMPACTS DURING COMMISSIONING (COMBINED IMPACTS BOTH CTGS)

Pollutant/Averaging Period	Modeled Concentration, μg/m³
NO_2 – 1-hour	127.5
CO – 1-hour	3228.0
CO - 8-hour	675.9

TABLE 4-4

MODELED MAXIMUM PROPOSED PROJECT IMPACTS

Pollutant	Averaging Time	Maximum Project Impact (μg/m³)	Background (μg/m³)	Total Impact (μg/m³)	State Standard (μg/m³)	Federal Standard (μg/m³)
NO_2	1-hour	127.5[a]	185.9	313	338	-
	Annual	0.1	22.5	23	56	100
SO_2	1-hour	4.3	110.0	114	650	-
	3-hour	2.0	78.6	81	-	1300
	24-hour	0.4	23.6	24	109	365
	Annual	0.0	10.5	11	-	80
CO	1-hour	3,228.0[a]	6,300	9,528	23,000	40,000
	8-hour	675.9[a]	3,800	4,476	10,000	10,000
PM_{10}	24-hour	1.2	58	59	50	150
	Annual	0.1	27	27	20	--
$PM_{2.5}$	24-hour	1.2	32.7	34	--	35
	Annual	0.1	14.1	14	12	15

Notes:

a. Impacts during gas turbine commissioning.

TABLE 4-5
COMPARISON OF MAXIMUM MODELED IMPACTS DURING NORMAL OPERATION AND PSD SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Significant Impact Level, $\mu g/m^3$	Maximum Modeled Impact for CECP, $\mu g/m^3$	Exceed Significant Impact Level?
NO_2	Annual	1	0.1	No
SO_2	3-hour	25	2.0	No
	24-Hour	5	0.4	
	Annual	1	0.0	
CO	1-Hour	2000	1134	No
	8-Hour	500	236	
PM_{10}	24-Hour	5	1.2	No
	Annual	1	0.1	

5.0 CONCLUSION

The results of the modeling indicate that the proposed facility operations including Commissioning and Startup/Shutdowns will not cause or contribute to an exceedance of the Federal and California Ambient Air Quality Standards for NO_2, SO_2 and CO.

For PM_{10}, background concentrations already exceed the annual and 24 hour California standard. Since the background is already in exceedance of the annual standard no additional violations can be due to facility operations. Additionally the 0.1 $\mu g/m^3$ predicted annual impact is well below PSD significant impact levels shown in Table 4-5. Predicted impacts less than SILs are normally considered to not significantly affect compliance with Federal Ambient Air Quality Standards regardless of the background level. Specifically in non-attainment areas, project impacts less than the SILs are deemed to not significantly cause or contribute to violations of the Federal Ambient Air Quality Standard. This can be considered the case for California Ambient Air Quality Standards as well.

Since the initial modeling estimated maximum 24 Hour PM_{10} impacts of approximately 1.2 $\mu g/m^3$, additional AERMOD modeling could be performed for all days in the 2004-2006 period that 24 Hour PM_{10} background concentrations were between 49 μ/m^3 and 50 $\mu g/m^3$ (California Standard) to determine whether additional violations would result from facility operations. There were no monitoring days that concentrations were measured within this range (highest monitored value less than the California Standard was 44 $\mu g/m^3$. Therefore it can be concluded that facility operations would not cause or contribute to additional violations of the California 24 Hour Ambient Air Quality Standard for PM_{10}.

The modeling results also indicate that no exceedance of the Federal annual or 24 hour PM2.5 standard is predicted. Monitored background levels exceeded the California annual standard. Since the background is already in exceedance of the annual standard no additional violations can be due to facility operations.

5.1 AFC SECTION 5.1 REVISIONS

The following are revisions to Tables included in Section 5.1, Air Quality of the original AFC (CEC) and application for an Authority to Construct (SDAPCD) submittal dated September, 2007.

TABLE 5.1-6

PM_{10} LEVELS IN SAN DIEGO COUNTY, ESCONDIDO MONITORING STATION, 1997-2006 (μg/m³)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 24-Hour Average	63	51	50	63	72	50	124*	58	42	52
Annual Arithmetic Mean (State Standard = 20 μg/m³)	29	24	30	30	31	25	33	27	24	24
Number of Days Exceeding:										
State Standard (50 μg/m³, 24-hour)	3	1	1	2	2	1	5	1	0	1
Federal Standard (150 μg/m³, 24-hour)	0	--	0	0	0	0	3	0	0	0

Source: California Air Quality Data, California Air Resources Board website (http://www.arb.ca.gov/adam/welcome.html; EPA AIRData website (http://www.epa.gov/air/data/index.html).

*Removed exceptional event value of 179

TABLE 5.1-7
$PM_{2.5}$ LEVELS IN SAN DIEGO COUNTY, ESCONDIDO MONITORING STATION, 1997-2006 (μg/m^3)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 24-Hour Average	--	--	64.0	66.0	60.0	54.0	38.0	67.0	43.0	41.0
Number of Days Exceeding:										
Federal Standard (65 μg/m^3, 24-hour)	0	0	0	1	0	0	0	1	0	0
(35 μg/m^3, 24-hour effective December 17, 2006)	--	--	--	--	--	--	--	--	--	--
98th Percentile	--	--	45.0	48.0	41.0	39.0	34.0	37.0	32.0	28.0
3-yr Average, 98th Percentile	--	--	--	--	44.7	42.7	38.0	36.7	34.3	32.3
Annual Arithmetic Mean (State Std = 12 μg/m^3)	--	--	18.0	15.8	17.5	16.0	14.1	14.1	12.3	11.5
3-yr Annual Average (Federal Std = 15 μg/m^3)	--	--	18	16	18	16	14	14	12	12

Source: California Air Quality Data, California Air Resources Board website (http://www.arb.ca.gov/adam/welcome.html; EPA AIRData website (http://www.epa.gov/air/data/index.html).

TABLE 5.1-29
Maximum Background Concentrations[a], project area, 2004-2006 (μg/m3)

Pollutant	Averaging Time	2004	2005	2006
NO_2 (Camp Pendleton)	1-hour	**185.9**	144.6	152.1
	Annual	**22.5**	22.5	20.7
SO_2 (San Diego)	1-hour	**110.0**	94.3	89.1
	3-hour	52.4	68.1	**78.6**
	24-hour	**23.6**	23.6	23.5
	Annual	**10.5**	7.9	10.5
CO (Escondido)	1-hour	**6,300**	5,900	5,700
	8-hour	**3,800**	3,100	3,600
PM_{10} (Escondido)	24-hour	**58**	42	52
	Annual	**27**	24	24
$PM_{2.5}$ (Escondido)	24-hour[b]	37	32	28
	Annual	**14.1**	12.3	11.5

Source: California Air Quality Data, California Air Resources Board website; EPA AIRData website. Reported values have been rounded to the nearest tenth of a μg/m^3 except for PM_{10} which were already rounded to the nearest integer.

Notes:

a. With the exception of 24-hr $PM_{2.5}$, bolded values are the highest during the three years and are used to represent background concentrations.

b. 24-hour average $PM_{2.5}$ concentrations shown are 98th percentile values rather than highest values because compliance with the ambient air quality standards is based on 98th percentile readings. Since the ambient standard is based on a 3-year average of the 98th percentile readings, the 3-year average of the 2004 to 2006 98th percentile readings was used to represent the background concentration.

APPENDIX B

APPROVAL OF HEALTH RISK ASSESSMENT

Rule 1200 Health Risk Assessment Report

Facility ID:	333A
Applications:	985745, 985746, 985747, and 985748.
Project Engineer:	Steve Moore
Toxics Risk Analyst:	Michael Kehetian
HRA Tool Used:	AERMOD - HARP
Report Date:	11/21/08

Review of Health Risk Assessment (HRA) evaluation for the Carlsbad Energy Center Project (CECP)

I. SUMMARY & CONCLUSION

SUMMARY

This health risk assessment (HRA) is an assessment of the potential health risks from the Carlsbad Energy Center Project (CECP) consisting of two combustion turbine generators with a nominal gross power output of 208 megawatts (MW) and with a corresponding heat input of 1976 million British thermal units per hour (MMBtu/hr) per turbine (without power augmentation at 61 °F average ambient temperature). At 37 °F the maximum heat input is 2085 MMBtu/hr without power augmentation. The combustion turbines are proposed to be equipped with a carbon monoxide (CO) catalyst to control CO and volatile organic compounds and a selective catalytic reduction system to control oxides of nitrogen. The CO catalyst also reduces toxic air pollutant emissions.

The combustion turbines are also equipped with evaporative coolers that can be used cool the inlet air to each turbine to increase power during periods of high ambient temperature. Additionally, a 240 horsepower diesel-fueled emergency fire pump engine is also part of the proposed project.

The applicant submitted toxic air pollutant emission factors, calculated emission rates, and HRA modeling results to evaluate the potential health impact during normal operations, startups and shutdowns, and commissioning. These results were reviewed and found to be technically accurate in so far as they estimated health impacts based on the emission factors and emission rates submitted.

In addition to the above submittal from the applicant, supplementary analyses based on the same receptor grid and meteorological data used in the applicant's submittal were prepared by the District to identify the likely worst-case potential health risk from the project using more extensive emission scenarios. Based on the applicant's submittal and the supplemental analyses, the expected and the likely worst-case potential health impacts from the emissions of toxic air contaminants for the project as compared to Rule 1200 significance levels are presented in Table 1-1.

The potential health impact at the point of maximum impact (PMI) in the tables elsewhere in this document is the maximum impact at a location beyond the facility's boundary. This location does not necessarily represent the maximum incremental cancer risk nor the total acute or chronic Health Hazard Index (HHI) because a person may not reasonably be expected to be present at the PMI location for the exposure period of concern.

It should be noted that the potential health risks presented in Table 1-1 are conservatively high due to the conservative assumptions specified in the California Office of Health Hazard Assessment (OEHHA) health risk assessment guidance. In addition, the health risks presented in Table 1-2 are based on an operating scenario that may be unrealistic—8760 hours of operation, including 1460 startups—and may not be possible because of constraints imposed by proposed permit conditions for criteria pollutants.

Table 1-1
Worst-Case Potential Health Impacts

Category	**Health Impact**	**Rule 1200 Significance Level**
Maximum Incremental Cancer Risk—Resident (per million)	0.71	1.0 or 10 (with TBACT)
Maximum Incremental Cancer Risk—Worker (per million)	0.54	1.0 or 10 (with TBACT)
Total Chronic Noncancer Health Hazard Index—Resident	0.017	1.0
Total Chronic Noncancer Health Hazard Index—Worker	0.019	1.0
Total Acute Noncancer Health Hazard Index—Resident	0.57	1.0
Total Acute Noncancer Health Hazard Index—Worker	0.57	1.0

CONCLUSION

The indicated health impacts are all less than the Rule 1200 significance levels. Therefore, the project HRA is preliminarily approved. For an incremental cancer risk of less than one in a million, toxic best available control technology (TBACT) is not required. However, the combustion turbines are proposed to be equipped with a CO oxidation catalyst, which would be considered TBACT for this type of equipment. Thus, the project would be approvable with a cancer risk of up to 10 in a million.

II. EMISSION FACTORS

COMBUSTION TURBINE GENERATOR FACTORS—STANDARD OPERATIONS

Applicant Submitted Emission Factors

For standard operations, the applicant based the health risk analysis on toxic air pollutant emission factors in pounds per million standard cubic feet (lb/MMscf) of natural gas combusted. For the most part, emission factors for stationary combustion turbines in EPA's standard emission factor reference AP-42 (Table 3.1-3) and the California Air Toxic Emission Factor (CATEF) database for toxic compounds were used. The emission factor for ammonia was calculated based on the proposed permit limit of 5 parts per million by volume dry (ppmvd).

In some cases, the emission factors for emissions controlled by an oxidation catalyst were taken from the background document for the latest edition of AP-42. No control factor was assigned for the other toxic compounds. Emission rates were calculated from these emission factors based on a maximum heat input of 2085 MMBtu/hr and a higher heating value of 1019 Btu/scf for natural gas.

For polycyclic aromatic hydrocarbons (PAHs), only those compounds listed in CATEF that had a quantified unit risk factor (URF) for cancer were included. Conservatively, these were all assumed to be composite PAHs with the same risk factor as benzo(a)pyrene, which is used as a surrogate in risk analyses since its URF is higher than most PAHs. The emission factors proposed by the applicant are shown in Table 2-1.

Table 2-1
Normal Operation Emission Factors Proposed by Applicant

CHEMICAL NAME	Emission Factor, lb/MMscf	Reference	URF available
AMMONIA	6.95E+00	Permit	
ACETALDEHYDE	4.08E-02	AP-42	Y
ACROLEIN	3.69E-03	AP-42 (background)	Y
BENZENE	3.33E-03	AP-42 (background)	Y
BUTADIENE, 1,3-	4.39E-04	AP-42	Y
ETHYL BENZENE	3.26E-02	AP-42	Y
FORMALDEHYDE	3.67E-01	AP-42 (background)	Y
HEXANE, n-	2.59E-01	CATEF	
NAPHTHALENE	1.66E-03	CATEF	Y
PROPYLENE	7.71E-01	CATEF	
PROPYLENE OXIDE	2.96E-02	AP-42	Y
TOLUENE	1.33E-01	AP-42	Y
XYLENES	6.53E-02	AP-42	Y
PAHs			
BENZO[a]ANTHRACENE		CATEF	Y
BENZO[a]PYRENE		CATEF	Y
BENZO[b]FLUORANTHENE		CATEF	Y
BENZO[k]FLUORANTHENE		CATEF	Y
CHRYSENE		CATEF	Y
DIBENZ[a,h]ANTHRACENE		CATEF	Y
INDENO(1,2,3-cd)PYRENE		CATEF	Y
PAH (COMPOSITE)	1.31E-04	CATEF	Y

Normal Operation Emission Factors for District Supplemental Analyses

Although the applicant's proposed emission factors are conservative in some ways, the District elected to perform additional analyses based on a set of emission factors similar to a set that the District has based its most recent previous evaluation of a large combined-cycle turbine. With the exception of ammonia and formaldehyde, these emission factors are taken from AP-42 unless an AP-42 emission factor is not available. A uniform control factor of 50% to account for the use of a CO oxidation catalyst is applied to all emission factors except ammonia. The formaldehyde emission factor is taken from CATEF since the controlled emission factor is most representative of recent compliance source tests for a large combined-cycle turbine. All PAHs listed in CATEF are represented. Those without an approved URF are quantified as composite PAHs. These emission factors are shown in Table 2-2.

Table 2-2
District Emission Factors

CHEMICAL NAME	Emission Factor (Uncontrolled), lb/MMscf	Emission Factor (Controlled), lb/MMscf	Reference
AMMONIA	6.95E+00	6.95E+00	Permit
ACETALDEHYDE	4.08E-02	2.04E-02	AP-42
ACROLEIN	6.53E-03	3.27E-03	AP-42
BENZENE	1.22E-02	6.10E-03	AP-42
BUTADIENE, 1,3-	4.39E-04	2.20E-04	AP-42
ETHYL BENZENE	3.26E-02	1.63E-02	AP-42
FORMALDEHYDE	9.17E-01	4.59E-01	CATEF
HEXANE, n-	2.59E-01	1.30E-01	CATEF
NAPHTHALENE	1.33E-03	6.65E-04	AP-42
PROPYLENE	7.71E-01	3.86E-01	CATEF
PROPYLENE OXIDE	2.96E-02	1.48E-02	AP-42
TOLUENE	1.33E-01	6.65E-02	AP-42
XYLENES	6.53E-02	3.27E-02	AP-42
PAHs			
ACENAPTHENE		9.50E-06	CATEF
ACENAPTHYLENE		7.35E-06	CATEF
ANTHRACENE		1.69E-05	CATEF
BENZO[a]ANTHRACENE	2.26E-05	1.13E-05	CATEF
BENZO[a]PYRENE	1.39E-05	6.95E-06	CATEF
BENZO[b]FLUORANTHENE	1.13E-05	5.65E-06	CATEF
BENZO(e)PYRENE		2.72E-07	CATEF
BENZO(g,h,i)PERYLENE		6.85E-06	CATEF
BENZO[k]FLUORANTHENE	1.10E-05	5.50E-06	CATEF
CHRYSENE	2.52E-05	1.26E-05	CATEF
DIBENZ[a,h]ANTHRACENE	2.35E-05	1.18E-05	CATEF
FLUORANTHENE		2.16E-05	CATEF
FLUORENE		2.90E-05	CATEF
INDENO(1,2,3-cd)PYRENE	2.35E-05	1.18E-05	CATEF
PHENANTHRENE		1.57E-04	CATEF
PYRENE		1.39E-05	CATEF
PAH (COMPOSITE)	5.24E-04	2.62E-04	CATEF

COMBUSTION TURBINE GENERATOR EMISSION FACTORS—STARTUP, SHUTDOWN, AND COMMISSIONING

Startup and Shutdown Emission Factors

For startup and shutdown emissions, the emission factors in Table 2-3 were used, as applicable, both for analyses performed by the applicant and reviewed by the District and District supplemental analyses. The applicant used the emission factors for acetaldehyde, acrolein, benzene, and formaldehyde in modeling potential acute health impacts.

As indicated many of these emission factors were derived from a source test. The source test was performed during the first hour of a cold start of a natural gas-fired GE 7FA gas turbine at the Palomar Energy Center. This is a combined-cycle turbine with ultra-low-NOx combustors. The turbine was equipped with a CO oxidation catalyst. During the first hour of the startup, the turbine tested was operating at very low loads (0–18%). Although the oxidation catalyst control efficiency was not quantified during the test it is assumed the catalyst was operating at reduced efficiency during a large portion of the hour because of the low temperatures in the heat recovery steam generator where the catalyst is located.

The District only considers these emission factors to be potentially applicable at loads below the point where the ultra-low-NOx combustors are no longer operating in the low-NOx mode (typically 40-60% of maximum load). This would include shutdown operations. However, emissions during a shutdown are likely to be overestimated with these emission factors because the oxidation catalyst would be close to its normal operating temperature.

Table 2-3
Startup and Shutdown Emission Factors

CHEMICAL NAME	Emission Factor, lb/MMscf	Reference
AMMONIA	6.95E+00	Permit
ACETALDEHYDE	1.28E+00	Source Test
ACROLEIN	6.89E-02	Source Test
BENZENE	2.56E-02	Source Test
BUTADIENE, 1,3-	4.39E-04	AP-42
ETHYL BENZENE	3.26E-02	Source Test
FORMALDEHYDE	4.63E+00	Source Test
HEXANE, n-	2.59E-01	CATEF
NAPHTHALENE	1.04E-03	Source Test
PROPYLENE	7.71E-01	CATEF
PROPYLENE OXIDE	2.96E-02	AP-42
TOLUENE	9.28E-02	Source Test
XYLENES	3.48E-03	Source Test
PAHs		
ACENAPTHENE		CATEF
ACENAPTHYLENE		CATEF
ANTHRACENE		CATEF
BENZO[a]ANTHRACENE	2.25E-05	Source Test (ND)[a]
BENZO[a]PYRENE	1.39E-05	Source Test (ND)[a]
BENZO[b]FLUORANTHENE	1.13E-05	CATEF
BENZO(e)PYRENE		CATEF
BENZO(g,h,i)PERYLENE		CATEF
BENZO[k]FLUORANTHENE	1.10E-05	CATEF
CHRYSENE	2.25E-05	Source Test (ND)[a]
DIBENZ[a,h]ANTHRACENE	2.25E-05	Source Test (ND)[a]
FLUORANTHENE		CATEF
FLUORENE		CATEF
INDENO(1,2,3-cd)PYRENE	2.25E-05	Source Test (ND)[a]
PHENANTHRENE		CATEF
PYRENE		CATEF
PAH (COMPOSITE)	5.24E-04	CATEF

[a]These compounds were tested for but not detected during the source test. The emission factor is based on one half the detection limit.

Commissioning Emission Factors

Commissioning operations involve a wide-range of loads and add-on emission control effectiveness. During the early part of commissioning the oxidation catalyst is not typically installed and the turbine is operated at loads of 50% or less. In the absence of any other information, the District considers the startup and shutdown emission factors applicable to commissioning operations at loads of 50% or less.

Emergency Pump Engine Emission factors

The emission factors proposed by the applicant for the emergency diesel fire pump engine are based on Ventura County Air Pollution Control District Combustion Emission Factors for internal combustion diesel engines. The factors were reviewed by the District. The proposed emission factors are preliminarily determined to be representative of toxic air pollutant emissions from this emission unit.

III. MODELING

APPLICANT SUBMITTED MODELING

Modeling Procedures

In the modeling submitted, cancer, chronic, and acute risks were estimated using ARB's HARP Risk Analysis Module to determine source strengths (grams per seconds per microgram per cubic meter [(g/s)/ug/m^3] based on emission factors for the equipment proposed and operating scenarios. The source strengths were input into EPA's AERMOD dispersion model to directly estimate acute, chronic, and cancer health risks. The District independently reviewed the AERMOD model inputs for technical accuracy and adherence with ARB and OEHHA HRA guidance and District Rule 1200 standard procedures.

The following AERMOD model inputs (g/s per ug/m3) were reviewed:

- Annual and Hourly Emissions Rates (g/s)
- Cancer Potencies (mg/kg-d)-1
- Chronic and Acute Reference Exposure Levels (RELs) (ug/m3)
- Derived (Adjusted) Method Breathing Rate = 302 (L/kg-d)
- Worker Breathing Rate = 149 (L/kg-d)
- Worker Exposure (5 days per week, 245 days per year, 40 years)
- Muti-Pathway Oral (Dermal and Soil Ingestion)

A list of applicant submitted and other material reviewed is given in Attachment A.

Release Parameters

The release parameters used by the applicant are for combustion turbine normal operations, startup and shutdowns, and commissioning are shown in Tables 3-1a.

Because turbine loads and release parameters change during the startup hour the applicant submitted an analysis of startup and shutdown impacts based on a 4-phase startup/shutdown hour. The startup phases are:

- Phase 1. The first 12 minutes of the startup, which includes accelerating the turbine to full speed with no load and then subsequently ramping the turbine generator electrical output to the final load, which the applicant assumed was 100% of maximum load.

- Phase 2. The period from the end of the power ramp until the turbine achieves its BACT limits, which is proposed to take 10 minutes in a typical startup.
- Phase 3. Operation at the final load until the end of the hour or shutdown (31 minutes or 38 minutes with no shutdown). The final load was assumed to be 100% by the applicant.
- Phase 4. The shutdown time period, which is proposed to be 7 minutes, typically, by the applicant.

The applicant assumed that Phases 1 and 4 could be represented by the steady state operating conditions for 50% load. For the commissioning mode, the turbine was also assumed to be operating at 50% load.

Table 3-1a
Applicant Fuel Heat Input and Release Parameters for Startup, Shutdown, and Commissioning

Operating mode	Duration, min	Fuel Heat Input, MMBtu/hr	Stack Exhaust Temperature, °F	Exhaust Velocity, m/s
Normal Operations	N/A	2085	361	21.21
Startup				
Phase1	12	1093	346	12.24
Phase2	10	2070	361	20.80
Phase3	31	2070	361	20.80
Phase4	7	1093	346	12.24
Commissioning	N/A	1093	346	12.24

Emission Rates

For the combustion turbines, maximum emission rates for normal operations were based on a fuel heat input rate of 2085 MMBtu/hr or 2.04 MMscf per hour (fuel higher heating value of 1019.3 Btu/scf). This fuel heat input rate is equivalent to full load operation at low ambient temperature (without power augmentation) and greater than the fuel heat input rate with power augmentation at average ambient temperature. Normal operation emissions were also based on 4100 hours of operation per turbine per year.

For startups, shutdowns, and commissioning, the fuel heat input rates are based on operation at either 100% load (startup Phases 2 and 3) or 50% load (startup Phases 1 and 4 and commissioning). The heat input rates correspond to operation at average annual temperature including power augmentation at 100% load.

Source Strengths

Calculated source strengths based on standard HARP health risk factors and based on the applicant and District emission factors are shown in Table 3-2. The residential risk factors used were based on the derived adjusted OEHHA method (the applicant also calculated source strengths for worker exposure). When multiplied by the appropriate fuel heat input rate in MMBtu/hr, these source strengths, can be used as input emission rates in AERMOD in (g/s)/(ug/m^3) to allow the direct estimation of potential health impacts with AERMOD. The use of the adjustment factors is explained in Section IV.

Table 3-2
Source Strengths, g/s/[(ug/m^3)(MMBtu/hr)]

Category	Incremental Cancer Risk (per million) Source Strength	Chronic Noncancer Health Hazard Index Source Strength	Acute Noncancer Health Hazard Index Source Strength
Applicant Annual—Resident	2.98E-03	2.78E-05	3.15E-06
District Annual—Resident	5.96E-03	3.03E-05	2.99E-06
Adjustment Factor	2.00	1.09	0.95
Applicant Startup/Shutdown Commissioning	N/A	N/A	5.11E-05
District Startup/Shutdown Commissioning	1.52E-02	3.55E-04	5.11E-05

SUPPLEMENTAL MODELING

General

The District performed additional modeling to more fully examine potential health impacts. The modeling relied on the applicants submitted receptor grid and three-year (2003, 2004, and 2005) meteorological data, which the District has preliminarily approved. The modeling refined the startup, shutdown, and commissioning modeling for acute health impacts and addressed potential cancer and chronic health impacts from these operations.

Modeling Procedures

For startup and shutdown emissions the major refinement was to look at the potential impact of low stack exhaust temperatures during the first few minutes of a cold start, which could increase the emission impacts. The District was unable to directly obtain any information on the stack exhaust temperature during a startup of the proposed turbine. Based on the fact that the turbine is proposed, under normal circumstances, to achieve its BACT limits within 22 minutes of ignition. The stack exhaust temperature was assumed to rise linearly from ambient (68 °F) to its normal operating temperature in 22 minutes. For shutdowns, the minimum stack exhaust temperature was assumed to be the exhaust temperature at 50% load.

The turbine load was assumed to be 0% for first 5 minutes and then to rise at a rate of 30 MW per minute until the final operating load for the remainder of the startup hour was reached. This startup scenario was based on a presentation given by the turbine manufacturer[1]. The load was calculated on a minute-by-minute basis, and average heat inputs for the four phases of the startup were calculated based on information provided by the manufacturer for steady state part load operation at an ambient temperature of 41 °F. A higher heating value for natural gas of 1020 Btu/scf was used in emission factor calculations.

Even though the turbine is projected to achieve its BACT limits in 22 minutes, the applicant has requested a 60 minute startup period. Therefore, in all cases, the final load was assumed to be 50% of the maximum load for the remainder of the hour (or until shutdown) as a worst case analysis. A load of 50% was considered to be the worst case because: (1) this is the point of maximum fuel heat inputs at loads low enough for the much higher startup emission factors to be representative and (2) it is the point of minimum stack exhaust temperature at steady state conditions, based on manufacturer supplied data.

The release parameters used in the modeling are presented Table 3-3

Table 3-3
Fuel Heat Input and Release Parameters for Supplemental Modeling

Category	Duration, min	Fuel Heat Input, MMBtu/hr	Stack Exhaust Temperature, °F	Exhaust Velocity, m/s
Startup				
Phase1	12	780	138	8.07
Phase2	10	1257	281	11.49
Phase3	31 or 38	1257	346	12.50
Phase4	7 or 0	569	346	10.17
Commissioning	N/A	1257	346	12.50

[1]John Xia and Rick Antos, SGT6-5000F (W501F), 3 Million Hours Fleet Operational Experience, POWER-GEN International 2006, Orlando, FL, November 28-30, 2006.

IV. POTENTIAL HEALTH IMPACTS

NORMAL OPERATIONS

Applicant Results

The applicant's estimated potential health impacts for normal combustion turbine operations are shown in Table 4-1a. These health impacts include those from the diesel emergency pump, which are small compared to the combustion turbine impact.

Table 4-1a
Applicant Estimated Potential Health Impacts for Normal Operations

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Maximum Exposed Individual Resident	0.068	0.0019	0.036
Maximum Exposed Individual Worker	0.021	0.003	0.02
Point of Maximum Impact	0.1	0.003	0.09

Adjusted Normal Operation Results

To ensure that the HRA fully captured the potential health risks the applicant's estimated health risk for cancer and chronic impacts were adjusted by multiplying by the adjustment factors in Table 3.2 that are based on the ratio of the District source strengths to the applicant's source strengths. The differences in source strength ultimately derive from the differences in emission factors. Since the proposed permit contains no limits on hours of operation, the applicants estimated potential health risks were further adjusted by multiplying by the factor 8760/4100 to account for the possibility of operating every hour of the year. This would only be possible if criteria emissions could be reduced since operating hours are constrained by criteria emission limits in the proposed permit. The adjusted estimated potential health impacts are shown in Table 4-1b. The acute noncancer hazard index is not included in the adjustments because the adjusted impacts are used to evaluate impacts of startups and commissioning when normal operations are, by definition, not occurring.

Table 4-1b
Adjusted Estimated Potential Health Impacts for Normal Operations

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Maximum Exposed Individual Resident	0.2905	0.0044	N/A
Maximum Exposed Individual Worker	0.0897	0.0070	N/A
Point of Maximum Impact	0.4271	0.0070	N/A

STARTUP, SHUTDOWN, AND COMMISSIONING

Applicant Results

The applicant's estimated acute health impacts for combustion turbine startups and shutdowns and commissioning are shown in Table 4-1c. The startup and shutdown impacts assume that the turbines are simultaneously started and ramped to 100% load and remain there for 41 minutes of the startup hour (Phases 2 and 3). The commissioning impacts are based on the startup of one turbine to 100% load while the other is undergoing commissioning. The majority of the acute health impact during the startup comes from the 41-minute period of operation at 100% load. The District provided the emission factors used by the applicant for this analysis, but intended they only be used at low loads since they are not applicable at higher loads. Because of this, these results are not representative and are only presented for informational purposes.

The overall maximum hourly impacts are calculated by a weighted linear combination of the impacts for each individual startup phase. The fractional weighting factors were equal to the fraction of hour that the individual phase occupied (for example, the weight for Phase 1 is 0.2 since it lasts for 12 minutes).

Table 4-1c
Applicant Estimated Potential Acute Health Impacts for Startups, Shutdowns and Commissioning

Category	Acute Noncancer Health Hazard Index Startup and Shutdown	Acute Noncancer Health Hazard Index Commissioning
Maximum Exposed Individual Resident	0.33	0.33
Maximum Exposed Individual Worker	0.18	0.16
Point of Maximum Impact	0.76	0.60

Supplemental Results

The District performed additional analyses of the potential health impacts from startups, shutdowns, and commissioning. The worst case was assumed to be a startup to 50% load and commissioning at 50% load.

For simplicity, and conservatism, only the point of maximum impact was examined. Preliminary modeling showed that the difference in impacts between the two turbines was not significant, so only a single turbine was modeled. For simultaneous startup of both turbines the single turbine impacts were doubled for the combined impact. For commissioning, both the commissioning emissions and startup emissions were assumed to originate from the same stack.

The input source strengths for each startup phase were weighted as explained above to generate the combined potential health impact for all four phases directly from AERMOD. Potential cancer and chronic health impacts were estimated as well as acute. The following cases were examined:

- Simultaneous startup of both turbines with shutdown occurring at the end of the startup hour;
- Simultaneous startup of both turbines with the turbines operating without shutdown for the remainder of the hour (at 50% load);
- For acute impacts only, startup of one turbine with shutdown occurring at the end of the startup hour while the other turbine is in commissioning mode;
- For acute impacts only, startup of one turbine with the turbine operating without shutdown for the remainder of the hour while the other turbine is in commissioning mode; and
- For cancer and chronic impacts, both turbines in commissioning mode. This scenario is only used to calculate combined health impacts (see below).

In all cases, emissions were assumed to occur for 8760 hours per year. The estimated potential health impacts are presented for the worst case in Table 4-2 at the point of maximum impact. For startups, the worse case was uniformly the case where the turbine or turbines starting up operated the remainder of the hour at 50% load (i.e., no shutdown occurred in the startup hour).

Table 4-2
Supplemental Estimated Potential Health Impacts—Point of Maximum Impact

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Simultaneous Startup of Both Turbines	2.516	0.0588	0.444
Startup of One Turbine While the Other Turbine is Commissioning	N/A	N/A	0.572
Commissioning Both Turbines	1.9	0.0456	N/A

COMBINED ANNUAL IMPACTS

Methodology

Estimated potential cancer and chronic health impacts were estimated by combining the adjusted normal operation impacts with the estimated startup, shutdown, and commissioning impacts. The following equation was used to estimate combined chronic impacts:

$$HI = [(N - S - C)/8760]\, R_n + (S/8760)R_s + (C/8760)R_c$$

where:

HI is the combined health impact;

N is the maximum number of normal operating hours per turbine;

S is the number of startup hours per turbine;

C is the number of commissioning hours per turbine;

R_n is the maximum estimated potential health impact for 8760 hours of normal operations for both turbines combined;

R_s is the maximum estimated potential health impact for 8760 hours of startups for both turbines combined; and

R_c is the maximum estimated potential health impact for 8760 hours of commissioning for both turbines combined

For estimating combined potential cancer health impacts, the same formula was used when a commissioning year is not included (standard years). For estimating potential cancer health impacts including one year of commissioning, the following equation was used:

$$HI = [(N - S - (1/70)*C)/8760]\ R_n + (S/8760)R_s + (1/70)(C/8760)R_c$$

The above method is conservative in that it does not account for temporal and spatial variation in the location of the separate maximum estimated potential health impacts associated with normal operations, startups, and commissioning.

Combined Operating Scenarios

Table 5-1 defines the basis for estimating the expected and worst case potential health impacts. The worst case is based on the 1460 startups since the number of startups per turbine is limited to 1460 by proposed permit conditions.

Table 5-1
Combined Annual Health Impact Basis

Scenario	Maximum Normal Operating Hours per Turbine	Number of Startups per Turbine	Commissioning Mode Hours per Turbine
Standard Year			
Expected	4100	300	0
Worst Case	8760	1460	0
Commissioning Year			
Expected	4100	300	415
Worst Case	8760	1460	415

Maximum Potential Impacts

Tables 5.2a, 5.2b, 5.2c, and 5.2d present the maximum expected and worst-case potential health impacts.

Table 5-2a
Expected Maximum Potential Health Impacts—Standard Year

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Maximum Exposed Individual Resident	0.22	0.004	
Maximum Exposed Individual Worker	0.14	0.005	
Point of Maximum Impact	0.28	0.005	0.44

Table 5-2b
Expected Maximum Potential Health Impacts— Including the Commissioning Year

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Maximum Exposed Individual Resident	0.22	0.006	
Maximum Exposed Individual Worker	0.14	0.007	
Point of Maximum Impact	0.28	0.007	0.57

Table 5-2c
Worst-Case Potential Health Impacts—Standard Year

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Maximum Exposed Individual Resident	0.71	0.015	
Maximum Exposed Individual Worker	0.54	0.017	
Point of Maximum Impact	0.82	0.017	0.44

Table 5-2d
Worst-Case Potential Health Impacts—Including the Commissioning Year

Category	Incremental Cancer Risk (per million)	Chronic Noncancer Health Hazard Index	Acute Noncancer Health Hazard Index
Maximum Exposed Individual Resident	0.71	0.017	
Maximum Exposed Individual Worker	0.54	0.019	
Point of Maximum Impact	0.83	0.019	0.57

ATTACHMENT A

As part of this review following submittals and documents were reviewed:

- Carlsbad Energy Center Project, California Energy Commission, Docket No. 07-AFC-6. Revised (5/11/08) Modeling Input Summary Tables: Attachment DR84-90-3. June 6, 2008.
    - Table 5.9B-1: Annual and Maximum Hourly Non-Criteria Pollutant Emissions From Gas Turbines during Normal Operation.
    - Table 5.9-6 (Revised 5/11/08): Summary of Potential Health Risks.
    - Table 5.9B-5: Calculation of Cancer Risk for Gas Turbines and Diesel Emergency Fire Pump.
    - Table 5.9B-6: Calculation of Gas Turbine Acute and Chronic Heath Hazard Indexes.
    - Table 5.9B-8: Calculation of Diesel Emergency Fire Pump Acute Health Hazard Index.

- Application for Authority to Construct for the Proposed Carlsbad Energy Center Project: Additional Acute Health Hazard Modeling Analysis. September 24, 2008.
    - Table A-4, 9/24/08: Calculation of HHI Modeling Inputs for Gas Turbines during Startup Phases 1 plus 4 using SDAPCD Emission Factors.
    - Table A-5, 9/24/08: Calculation of HHI Modeling Inputs for Gas Turbines during Startup Phases 2 plus 3 using SDAPCD Emission Factors.

- SDAPCD Air Quality Impact Analysis, Final Review Report, Carlsbad Energy Center Project (Application 985423). September 24, 2008.

APPENDIX C

PROPOSED PERMIT CONDITIONS

CECP PROPOSED PERMIT CONDITIONS

GENERAL CONDITIONS

1. This equipment shall be properly maintained and kept in good operating condition at all times and, to the extent practicable, 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]

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

3. The applicant 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]

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

5. For each combustion turbine, prior to the initial startup date of that turbine, the applicant shall surrender to the District Class A Emission Reduction Credits (ERCs) in an amount equivalent to 23.91 tons per year of oxides of nitrogen (NOx) to offset the net maximum allowable increase of 19.93 tons per year of NOx emissions for that turbine. [Rule 20.3(d)(8)]

6. Prior to the earlier of the two dates for the initial startup date of the two turbines the applicant shall surrender to the District Class A Emission Reduction Credits (ERCs) in an amount equivalent to 0.06 tons per year of oxides of nitrogen (NOx) to offset the net maximum allowable increase of 0.05 tons per year of NOx emissions from the emergency fire pump engine. [Rule 20.3(d)(8)]

7. Pursuant to 40 CFR §72.30(b)(2)(ii) of the Federal Acid Rain Program, the applicant 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]

8. The applicant 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]

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]

COMBUSTION TURBINE CONDITIONS

Definitions

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)]

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)]

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)]

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 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. [Rule 20.3(d)(1)]

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]

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)]

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 pemittee notifies the District the commissioning period has ended. [Rule 20.3(d)(1)]

17. For each combustion turbine, the shakedown period is the period of time commencing with the initial startup of that turbine and ending the sooner of 180 calendar days from the initial startup or the date the permittee notifies the District that the shakedown period has ended. [Rules 20.1(c)(16) and 21 and 40 CFR §52.21]

18. Turbine A is the combustion turbine as described on Applications No. 985745 or No. 985747, 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 and 40 CFR §52.21]

19. Turbine B is the combustion turbine as described on Applications 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 A is the turbine described on Application No. 985747. [Rules 20.1(c)(16) and 21 and 40 CFR §52.21]

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. Periods of operation at low load shall not exceed 130 minutes in any calendar day nor an aggregate of 780 minutes in any calendar year. No low load operation period shall begin during a startup period. [Rule 20.3(d)(1)]

21. Unit operating day means, for each combustion turbine, any calendar day in which the turbine combusts fuel. [40 CFR Part 60 Subpart KKKK]

General Conditions

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]

23. The combustion turbines shall be fired on Public Utility Commission (PUC) quality natural gas. The permitee shall maintain, on site, daily and 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)]

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)]

Emission Limits

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]

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]

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)]

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)]

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)]

30. When a combustion turbine is operating, the volatile organic compound (VOC) concentration, calculated as methane, measured in the exhaust stack, 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 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)]

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]

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]

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]

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]

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 permittee, the average NOx emission rate in pounds per megawatt-hour (lb/MWh) shall not exceed an average emission limit calculated in accordance with 40 CFR Section 60.4380(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 period. The hourly emission concentration limit and emission rate limit shall be 15 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 averages shall exclude all clock hours occurring before the Initial Emission 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]

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)]

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]

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. [Rule50]

39. Mass emissions from each combustion turbine 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.

	Pollutant	*Emission Limit, lb*
i.	*Oxides of Nitrogen, NOx (calculated as NO_2)*	*15.1*
ii.	*Carbon Monoxide, CO*	*9.2*
iii.	*Volatile Organic Compounds, VOC*	*5.3*

[Rule 20.3(d)(2)]

40. Excluding any minutes that are coincident with a shutdown period, cumulative mass emissions during a combustion turbine's startup period shall not exceed the following limits during any startup period, except during that turbine's commissioning period.

	Pollutant	*Emission Limit,lb*
i.	*Oxides of Nitrogen, NOx (calculated as NO_2)*	*69.2*
ii.	*Carbon Monoxide, CO*	*545*
iii.	*Volatile Organic Compounds, VOC*	*16.3*

[Rule 20.3(d)(1)]

41. Cumulative mass emissions during a combustion turbine's shutdown period shall not exceed the following limits during any shutdown period, except during that turbine's commissioning period.

	Pollutant	*Emission Limit,lb*
i.	*Oxides of Nitrogen, NOx (calculated as NO_2)*	*25.7*
ii.	*Carbon Monoxide, CO*	*277*
iii.	*Volatile Organic Compounds, VOC*	*7.0*

[Rule 20.3(d)(1)]

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)]

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)(i)]

44. Beginning with the earlier of 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); 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*
i.	*Oxides of Nitrogen, NOx (calculated as NO_2)*	*72.76*
ii.	*Carbon Monoxide, CO*	*339.9*
iii.	*Volatile Organic Compounds, VOC*	*25.0*
iv.	*Particulate Matter Less than 10 Microns, PM10*	*39.0*
v.	*Oxides of Sulfur, SOx (calculated as SO_2)*	*5.6*

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 and 40 CFR §52.1]

45. For each calendar month, the applicant shall maintain records, as applicable, on a calendar monthly basis, of mass emissions during each calendar month of NOx (calculated as NO_2), CO, VOCs, PM10, PM2.5, 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 and 40 CFR §52.1]

46. For each calendar month and each rolling 12-calendar-month period, the applicant shall maintain records, as applicable, on a calendar monthly basis, of aggregate mass emissions of NOx (calculated as NO_2), CO, VOCs, PM10, PM2.5, 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 and 40 CFR §52.1]

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

Ammonia - SCR

48. Not later than 90 calendar days prior to the start of construction, the applicant 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 and the oxidation catalyst CO control efficiency versus temperature and space velocity. 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]

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. [Rules 20.3(d)(1)]

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. 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. [Rules 20.3(d)(1)]

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 permits), 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. [Rules 20.3(d)(1)]

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]

Testing

53. All source test or other tests required by this permit 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 Part 60 Subpart KKKK and 40 CFR §60.8]

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 test 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]

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 to 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]

56. Within 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 and CO concentrations and emissions and 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.

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

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, using District approved methods. The renewal source test and the NOX and CO Relative Accuracy Test Audit (RATA) tests 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. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

58. Relative Accuracy Test Audit (RATA) tests and all other required certification tests shall be performed and completed on the CEMS in accordance with applicable provisions of 40 CFR Part 75 Appendix A and B performance specifications and 40 CFR §60.4405. [40 CFR Part 60 Subpart KKKK and 40 CFR Part 75]

59. Within 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]

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 permittee 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]

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]

62. The sulfur content of the combustion turbine fuel shall be sampled daily in accordance with ASTM D5287–97, Standard Practice for Automatic Sampling of Gaseous Fuels, 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) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

CONTINUOUS MONITORING

63. The applicant shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. []

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;
   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. Annual 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. Annual mass emission of carbon monoxide (CO), in tons;

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

65. No later than 90 calendar days prior to initial startup of each combustion turbine, the applicant 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]

66. No later than 60 calendar days after each combustion turbine commences commercial operation (defined for purposes of this condition as the first instance when power is sold to the electrical grid), a Relative Accuracy Test Audit (RATA) and other required certification tests shall be performed an completed on the that turbine's CEMS in accordance with 40 CFR Part 75 Appendix A Specifications and Test Procedures. At least 60 calendar days prior to the test date, the applicant 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. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

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 test, as required in 40 CFR 75.62. [40 CFR Part 75]

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

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 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

70. When the CEMS is not recording data and the combustion turbine is operating, hourly NOx emissions for purposes of annual emission calculations shall be determined in accordance with 40 CFR 75 Subpart C. Additionally, hourly CO emissions for annual 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]

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]

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]

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 (including 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]

74. At least 90 calendar days prior to the Initial Emissions Source Test , the applicant 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 Test Protocol. [Rule 20.3(d)(1)]

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

76. Each combustion turbine shall be equipped with continuous monitors to measure, calculate and record the following operational characteristics:

    A. Hours of operation, in hours;
    B. Natural gas flow rate to the combustion turbine, in standard cubic feet per hour;
    C. Total heat input to the combustion turbine based the fuels higher heating value, 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, in degrees Fahrenheit;

F. Combustion turbine energy output in megawatts hours (MWh); and
G. Steam turbine energy output in megawatts hours (MWh).

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 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

77. At least 90 calendar days prior to initial startup of the each combustion turbine, the applicant shall submit a turbine monitoring protocol to the District for written approval. This may be part of 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]

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 daily operation; and total cumulative hours of operation during each calendar year. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

Commissioning and Shakedown

79. Before the end of the commissioning period for each combustion turbine, the applicant 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)]

80. Thirty calendar days after the end of the commissioning period for each combustion turbine, the applicant shall submit a written progress report to the District. This report shall include, 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 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 inlet 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)]

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]

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); particulate matter less than or equal to 10 microns in diameter (PM10); and oxides of sulfur (SOx), calculated as sulfur dioxide (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*
i.	*Oxides of Nitrogen, NOx (calculated as NO_2)*	*36.40*
ii.	*Carbon Monoxide, CO*	*169.95*
iii.	*Volatile Organic Compounds, VOC*	*12.5*
iv.	*Particulate Matter Less than 10 Microns, PM10*	*19.5*
v.	*Oxides of Sulfur, SOx (calculated as SO_2)*	*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 shall not apply on and after the date Turbine B completes its shakedown period. [Rules 20.3(d)(3), 20.3(d)(8) and 21 and 40 CFR §52.1]

83. Beginning with the date Turbine A completes its shakedown period, aggregate emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2); carbon monoxide (CO); volatile organic compounds (VOCs); particulate matter less than or equal to 10 microns in diameter (PM10); and oxides of sulfur (SOx), calculated as SO_2, 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*
i.	*Oxides of Nitrogen, NOx (calculated as NO_2)*	*16.33*
ii.	*Carbon Monoxide, CO*	*214.85*
iii.	*Particulate Matter Less than 2.5 Microns, PM2.5*	*21.78*
iv.	*Particulate Matter Less than 10 Microns, PM10*	*26.91*

The aggregate emissions of each pollutant shall include emissions during all times that the equipment is operating including, but not limited to, emissions during startup, shutdown, and tuning periods. [Rules 20.3(d)(3), 20.3(d)(8) and 21 and 40 CFR §52.1]

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 and 40 CFR §52.1]

85. For each calendar month and each rolling 12-calendar-month period, the applicant 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). 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 and 40 CFR §52.1]

86. For each calendar month, the applicant 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 and 40 CFR §52.1]

87. For each calendar month and each rolling 12-calendar-month period, the applicant 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. 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 and 40 CFR §52.1]

88. No later than 18 months before the initial startup of either combustion turbine, the applicant 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 emission 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 and 40 CFR §52.1]

89. For each combustion turbine, the applicant shall submit the following notifications 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 later 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.

[40 CFR Part 60 Subpart KKKK, 40 CFR Part §60.7, 40 CFR Part 63 Subpart YYYY, and 40 CFR Part §63.9]

CONDITIONS FOR EMERGENCY FIRE PUMP ENGINE

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 IIII, and 40 CFR Part 63 Subpart ZZZZ]

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]

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

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

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

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]

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. [Rule 69.4.1, 17 CCR §93115, and 40 CFR Part 60 Subpart IIII]

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]

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]

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]

ATTACHMENT 2

EPA MORRO BAY POWER PLANT PSD DETERMINATION

Morro Bay Power Plant Modernization Project
US EPA Response to Comments
Proposed Prevention of Significant Deterioration Air Permit

Introduction

On May 17, 2006, the Region 9 office of the United States Environmental Protection Agency (EPA) requested public comment on a proposed permit for the Prevention of Significant Deterioration (PSD) of air quality, issued in accordance with 40 CFR § 52.21 and Part 124, to LSP Morro Bay, LLC, for the construction and operation of the Morro Bay Power Plant Modernization Project (Modernization Project).

The proposed Modernization Project will consist of two combined cycle gas turbine block units. Each block unit will be capable of producing 600 MW of electrical power, and will consist of two 180 MW natural gas-fired turbines, two heat recovery steam generators with duct burners, one 240 MW steam turbine, and associated air pollution control equipment. The Modernization Project is subject to federal PSD regulations for particulate matter (PM) and particulate matter less than 10 microns in aerodynamic diameter (PM_{10}). Other air emissions from the proposed project, including PM_{10}, are regulated by the San Luis Obispo Air Pollution Control District (District), and are subject to District air permits. A timeline of the Morro Bay PSD Permit Issuance process is shown in Table 1.

During the 30-day public comment period, we received forty-six (46) comments by fax, electronic and U.S. postal mail, thirty-nine (39) of which requested a public hearing for the proposed permit. A public hearing was scheduled for October 24, 2006 in Morro Bay, California. Notice for the hearing was provided to all individuals who submitted comments on the proposed permit, the District, and representatives of the applicant. Additionally, a notice was published in three local newspapers on September 20, 2006: The Tribune (San Luis Obispo, California), the Central Coast Sun Bulletin (Morro Bay, California), and The Bay News (Morro Bay, California). The public hearing was held at the Veterans Memorial Hall at 209 Surf Street in Morro Bay, California, from 6:00 – 8:15 PM on Tuesday, October 24, 2006. A transcript and audio tape recording of the hearing was prepared by Merit Reporting and Video (San Luis Obispo, California), and a video tape is available through AGP Video (Morro Bay, California)[1].

The public comment period closed on October 30, 2006. Any documents upon which EPA relied in reaching a final permit decision, and as referenced in this response to comments, such as the Ambient Air Quality Impact Report (AAQIR) and PSD application, are contained in the Administrative Record. An index of the Administrative Record, many documents in it, and the public hearing transcript, will be made available at www.regulations.gov, linked from the EPA Region 9 website[2].

This document represents the official U.S. EPA response to comments received during the public comment period. Each comment is referenced in this response by number (Table 2). Table 2 includes only substantive comments related to the PSD permit, and does not include

[1] http://www.slo-span.org/cgi-bin/media.pl?folder=SM
[2] http://www.epa.gov/region9/air/permit/r9-permits-issued.html

correspondence that we received which only requested a public hearing. Two comments were generally in favor of the Modernization Project (# *17, 37*), and the remaining comments raised various concerns regarding the PSD permit and the health impacts of PM_{10}. Because many of these comments contain common themes, they are paraphrased and grouped by issue in this response.

Table 1: Timeline of Significant Events in the Morro Bay Modernization Project Application

Event	Date
Duke Energy Submits Application for Certification (AFC) to the California Energy Commission (CEC)	October 23, 2000
EPA Receives New PSD Permit Application	November 1, 2000
San Luis Obispo Air Pollution Control District Issues Final Determination of Compliance for District Application #3083	August 30, 2001
CEC Issues Part 1 of Final Staff Assessment	November 15, 2001
EPA Requests Concurrence from U.S. Fish and Wildlife Service (FWS) that Modernization Project Not Likely to Adversely Affect Any Federally Listed Species	November 27, 2001
EPA Requests Concurrence from National Marine Fisheries Service (NMFS) that Modernization Project Not Likely to Adversely Affect Any Federally Listed Species	November 30, 2001
CEC Issues Part 2 of Final Staff Assessment	December 19, 2001
CEC Issues Part 3 of Final Staff Assessment	April 25, 2002
NMFS Concludes Informal Consultation with EPA	May 17, 2002
EPA Requests ESA Consultation with FWS	April 10, 2003
CEC Approves Morro Bay Modernization Project	August 2, 2004
FWS Issues Biological Opinion to EPA	May 23, 2005
Duke Energy Submits Addendum to EPA to Implement Conditions of FWS Biological Opinion	June 23, 2005
Ownership of Morro Bay Power Plant changed from Duke Energy Morro Bay, LLC to LSP Morro Bay, LLC	May 4, 2006
EPA Proposes PSD Permit for Modernization Project and Opens Public Comment Period	May 17, 2006
EPA holds Public Hearing in Morro Bay, California	October 24, 2006
Public Comment Period for Proposed PSD Permit Closes	October 30, 2006

Table 2: Reference Numbers for Comments on the Morro Bay Power Plant (MBPP)			
No.	Commenter	Format[3]	Date
1	Tacker, Julie	A	June 14, 2006
2	Dorfman, Barry	A; B	June 14; October 24, 2006
3	McCurdy, Jack	A	June 14, 2006
4	Beebe, Curt	A	June 15, 2006
5	Massa-Gooch, Shelley	A	June 15, 2006
6	Perlstein, Abe	A	June 15, 2006
7	Wiley, Susan	A	June 15, 2006
8	Watson, Elaine	A	June 17, 2006
9	Smith, Marie	A	June 20; Sept. 23; Oct. 19, 2006
10	Fram, Joe	A	July 11, 2006
11	Heinemann, Susan	A; C	July 23; October 24, 2006
12	Coastal Alliance on Plant Expansion (CAPE)	D; A	September 28; October 30, 2006
13	Savage, Arline	A	October 24, 2006
14	Ewing, Roger	B	October 24, 2006
15	Johnson, Colleen	B	October 24, 2006
16	Sullivan, Nelson	B	October 24, 2006
17	Johnson, Garry	B	October 24, 2006
18	Carter, Joan	B	October 24, 2006
19	Hill, Phil	B	October 24, 2006
20	LaPlante, Pauline	B	October 24, 2006
21	Crotzer, Shoosh	B	October 24, 2006
22	Crotzer, Colby	B	October 24, 2006
23	Churney, Bonita	B	October 24, 2006
24	Lucas, Michael	B	October 24, 2006
25	Cole, Robin	B	October 24, 2006
26	Risley, Peter	B	October 24, 2006
27	Davis, Mandy	B	October 24, 2006
28	Sadowski, Richard	B	October 24, 2006
29	Nelson, David	B	October 24, 2006
30	Groot, Henriette	B	October 24, 2006
31	Nelson, Monique	B	October 24, 2006
32	Racano, Joey	B	October 24, 2006
33	Beetham, Margaret	B	October 24, 2006
34	Bruton, Marla Jo	B	October 24, 2006
35	Martony, Bill	B	October 24, 2006
36	Dorfman, Barry	B	October 24, 2006
37	Cinowalt, Roy	B; C	October 24, 2006
38	DeMeritt, Melody	B; C; A	Oct. 24; Oct. 24; Oct. 29, 2006
39	Merrill, Lynda	C	October 24, 2006
40	Nelson, David	C	October 24, 2006
41	Taylor, Keith	C	October 24, 2006
42	Winter, H. Leabah	C	October 24, 2006
43	Purcell-McWilliams, Catherine	A	October 30, 2006
44	San Luis Bay Chapter of the Surfrider Foundation	A	October 30, 2006
45	Santa Lucia Chapter of the Sierra Club	A	October 30, 2006
46	CAPE	A	October 30, 2006

[3] A = electronic mail, B = Oral Comments at Hearing, C = Written Comments at Hearing, D = U.S. Mail

Section A: Pre- and post-project emission rate estimates

1. *PM_{10} emission rates of 11 and 13.3 lb/hr estimated by Sierra Research are too low because they were determined using inappropriate EPA test methods. Emission rates of condensable particulate were underestimated by Sierra Research because they were based on EPA Method 8, which is not approved for the measurement of condensable fraction of PM_{10}. (# 12, 23, 29, 31, 43-46)*

Response to A-1:

Because EPA Method 8 is an approved test method for sulfuric acid mist, but not for the measurement of condensable particulates, commenters were concerned that emission limits, and thus air quality impacts, are underestimated by the applicant. However, it is noted on page14 of the February 6, 2002 transcript from the CEC Evidentiary Hearing[4] that PM_{10} emission limits proposed by Sierra Research were not based on actual source tests using EPA Method 8. Rather, the PM_{10} emission rates estimated by Sierra Research were based on engineering experience and judgment.

The proposed PSD permit requires performance tests pursuant to 40 CFR §60.8 (60 days after achieving maximum load but no later than 180 days after initial startup, and annually thereafter) for PM_{10} from the turbine exhaust stacks. The PSD permit does not allow the use of EPA Method 8 for condensable particulates; rather, the permit requires EPA Method 5 for filterable particulate matter (front-half) and EPA Method 202 for condensable particulates (back-half). Specifically, Method 202 test methodology must include a) one hour nitrogen purge b) the alternative procedure described in paragraph 8.1 to neutralize the sulfuric acid c) evaporation of the last 1 ml of the inorganic fraction by air drying following evaporation of the bulk of the impinger water in a 105 °C oven as described in the first sentence of section 5.3.2.3 of Method 202. The conditional test methods CTM-039 or 040, listed on the EPA Emission Measurement Center website: http://www.epa.gov/ttn/emc/ctm.html may be used in lieu of Method 202. The proposed PSD permit has been modified to include these test method specifications in the final permit. Additionally, EPA is currently assessing and improving available test methods for condensable particulate matter.

The proposed emission rates of 11 and 13.3 lb/hr are consistent with emission limits for similar facilities listed in the EPA RACT/BACT/LAER Clearinghouse (See Response to B-1 and Table 3). Additionally, the proposed PM_{10} emission rates for each turbine block unit, converted into PM_{10} emission factors, i.e., PM_{10} production per unit energy (0.0054 and 0.0065 lb/MMBtu), are comparable to emission factors for

[4] http://www.energy.ca.gov/sitingcases/morrobay/documents/index.html

total PM (sum of filterable and condensable PM) from natural gas fired turbines (0.0066 lb/MMBtu), reported in Chapter 3-1 of AP 42, the EPA compilation of emission factors.

PM_{10} emission limits on the basis of lb/hr and ton per year (tpy) are separately enforceable conditions in the PSD permit (Permit Condition IX.B). Therefore, if the facility exceeds the PSD permit limits of 11 and 13.3 lb/hr without and with duct burner firing, or 203.2 tpy PM_{10}, the facility would be out of compliance and subject to enforcement action.

2. *The calculation of the change in emissions resulting from the project uses a baseline period (1998 – 2000) that is not representative of normal operating conditions. The baseline period includes a period of high energy production, fueled by the California Energy Crisis, and thus improperly inflates the actual emissions used to calculate the net emissions increase for the purpose of PSD applicability. The MBPP has most recently operated at reduced capacity. This recent period is the appropriate baseline period to use for the PSD analysis. (# 12, 29, 31, 34, 43-46)*

Response to A-2:

The PSD permit application submitted by Sierra Research, Inc. in November 2000 uses a 24-month baseline period from August 1998 – July 2000. Sierra Research additionally provided emissions data from January 1997 – July 2000. These data (Appendix 6.2-1.1) show a general pattern of higher criteria pollutant emissions during the late summer to early fall months. The competitive electric market in the State of California began on March 31, 1998, and was operated by the California Independent Systems Operator (ISO) and the Power Exchange (now bankrupt). According to the ISO, the competitive market began smoothly with electricity prices seemingly just and reasonable, until May 2000, when the first signs of a market crisis emerged[5]. The ISO reports that the California energy crisis continued until about May 2001. The baseline period used for the PSD applicability emissions calculations was August 1998 – July 2000, thus, the end of the 24-month baseline coincides with roughly 3 months at the beginning of the energy crisis in California.

Reform rules to the New Source Review (NSR) program, which includes the PSD regulations, promulgated on December 31, 2002 (67 Federal Register 80,186), and implemented March 3, 2003, codified existing policy for calculating "baseline actual emissions" (40 CFR §52.21(b)(48)(i)):

"For any electric utility steam generating unit, baseline actual emission means the average rate, in tons per year, at which the unit actually emitted

[5] http://www.caiso.com/docs/09003a6080/14/c5/09003a608014c508.pdf

the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation."

Based on the NSR Reform regulations, in determining the appropriate baseline period for an electric utility steam generating unit, the source must consider a consecutive 24-month period within the 5-year period immediately preceding actual construction. The source may select and EPA may allow the use of a different time period if such period is determined to be more representative of normal source operation.

The MBPP submitted their Application for Certification (AFC) to the California Energy Commission (CEC), and their PSD permit application to EPA, in November 2000 (see Table 1), using a consecutive 24-month baseline period of August 1988 – July 2000, which was within the 5-year period preceding the scheduled construction date. Although the baseline period chosen by MBPP was appropriate at the time the application was submitted in 2000, because the PSD permitting process has, to date, spanned 7 years, the baseline period must be re-examined, taking into account the 2002 NSR Reform regulations. Assuming actual construction on the project begins in 2007, the five year period, within which to choose the 24-month baseline, incorporates 2002 – 2006.

Beginning in September 2002 – December 2006, MBPP operated at significantly reduced capacity, with a corresponding significant reduction in emissions. During this time, MBPP typically operated only two of the four boilers. Because the boilers are old (circa 1950's -1960's), and MBPP had applied in 2000 to replace them with new combined cycle gas turbines, the reduced operation of the old boilers from 2002 - 2006 is not representative of "normal source operation", as normal operation would not occur at such significantly reduced capacity (in anticipation of boiler replacement), for such an extended period of time. By September 2002, when reduced operation of the boilers first began, the CEC had already issued their final approval of the Modernization Project in their three part Final Staff Assessments (April 2002, see Table 1). At that time MBPP did not expect that the EPA PSD permitting process, and the associated Section 7 ESA Consultation with the U.S. Fish and Wildlife Service, would require an additional 4 – 5 years. Therefore, MBPP determined that reduced operation of the boilers, in anticipation of their pending replacement, from September 2002 – December 2006, is not representative of normal source operation and hence indicated their desire to select a baseline period outside of the 2002 – 2006 period.

Because EPA shall allow use of a different time period upon a determination that it is more representative of normal source operation, we examined emissions of CO and NO_x from the MBPP over January 1997 – December 2006, a 10-year period preceding the revised construction date of 2007. Although we did not have VOC and PM_{10} data for August 2000 – December 2006, NO_x is an appropriate indicator for VOC and PM_{10} trends because emissions of VOC and PM_{10} correlated well with NO_x ($R^2 = 0.93$) over the period that we had data for all pollutants (January 1997 – July 2000). To determine a representative 24-month baseline within the 10-year look-back period, we calculated the average annual emissions based on a 24-month rolling average over the entire 10-year period from January 1997 – December 2006. We then selected the 24-month baseline period where actual annual emissions data most closely match the 10-year average. It is important to note that the average determined from this methodology still accounts for the "highs and lows" of operation during the 10-year period, encompassing both the energy crisis from mid-2000 to mid-2001, and the recent extended period of reduced operation from mid-2002 to late-2006. From this analysis, we determined that the period from June 1998 – May 2000 is the most representative period of normal operation over the 10-year period. This represents a two month shift backwards in time compared to the baseline period used by the facility in their original application (August 1988 – July 2000).

Using this most representative baseline period, while the proposed emissions increase from the project (baseline actual emissions to potential to emit) is higher, it has the same result, relative to PSD applicability, as the baseline period selected by MBPP. In other words, using the 24-month baseline period EPA has determined to be most representative of the previous 10-years, the Modernization Project still triggers PSD only for PM_{10} emissions, and does not trigger PSD for SO_2, CO, NO_x, and VOC. Therefore, although a different baseline period is more appropriate than the one used by MBPP (since the 5-year pre-construction window has shifted), it does not impact the PSD applicability determination. Additionally, if ambient air quality models used the lower baseline emission rate from the more representative 24-month baseline period (June 1998 – May 2000), the results would show that the Modernization Project has a lower impact on air quality than projected in the original Ambient Air Quality Impact Analysis (See Response to Comment C-4).

3. *The PSD analysis fails to consider Emission Reduction Credits, or "offsets" that were used to show compliance with state and local air quality standards, despite the fact that emissions would still increase. These offsets hide the real amount of emissions that the public would be exposed to. (# 44, 46)*

Response to A-3:

The Prevention of Significant Deterioration (PSD) program is the arm of the New Source Review (NSR) Program that regulates emissions of air pollutants for which the area is designated attainment or unclassifiable, from new major stationary sources or major modifications at existing major sources. The PSD regulations require the application of Best Available Control Technology (BACT), analyses of the impacts of the project on 1) PSD increments, 2) ambient air quality, 3) visibility and air quality in Class I areas, and 4) soils and vegetation. See 42 U.S.C. 7475. Offsets are not required by PSD; rather they are a component of the Nonattainment New Source Review (NNSR) Program, the arm of the NSR program that regulates emissions of air pollutants for which the area is designated nonattainment. See 42 U.S.C. 7503(a)(1)(A).

San Luis Obispo Air Pollution Control District Rule 204(B) is a local regulation that requires MBPP to mitigate emissions of any pollutant emitted above certain thresholds. Based on that regulation, the SLOAPCD will require offsets for the Modernization Project for emissions of NO_x, PM_{10}, SO_2, VOC, and CO.

In summary, for PSD purposes, offsets are not required for the Modernization Project because the project will be located in a Federal Attainment area for PM_{10}. The emission increase considered in the PSD analysis is based on the difference between the pre- and post-project emission rates. It would be improper for the PSD analysis to account for PM_{10} offsets because the purpose of offsets is yield a null net emission increase from the project. In this case, if the PSD analysis considered full offsets for PM_{10}, the net emissions increase would be zero. EPA also notes that the purpose of offsets is not to hide the real amount of emissions, as stated in the above comment, but to mitigate the effects of emissions increases in nonattainment areas to allow for new construction without affecting plans for nonattainment areas to achieve attainment. Offsets are not used to circumvent PSD or nonattainment NSR review; rather, offsets are required *as a result* of nonattainment NSR review or district review of project applications.

Section B: Best Available Control Technology (BACT)

1. *The BACT determination from 2000 is too old, and should be updated. (# 10, 12, 21, 24, 29-31, 44, 46)*

<u>Response to B-1</u>:

EPA agrees that the BACT determination made in 2000 should be reviewed to ensure that it is consistent with a 2007 BACT Determination.

The BACT determination was reviewed in 2006 prior to the proposal of the PSD permit, and has been reviewed again in 2007. According to 40 CFR §52.21(j)(4), BACT determinations must be reviewed and modified as appropriate at the latest reasonable time which occurs no more than 18 months prior to commencement of construction. Although §52.21(j)(4) applies to phased construction projects, the 18 month time period provides a guideline for how often BACT determinations must be revisited, given the possibility for improvements in technology, and when construction must be commenced after PSD permit issuance. Because PM_{10} is the only criteria pollutant subject to federal PSD requirements, PM_{10} is the only pollutant requiring a BACT determination.

BACT determinations may be an emission limitation, a design, equipment, work practice, operational standard, or combination thereof (40 CFR §52.21(b)(12)). From gas turbines, PM_{10} is emitted in part from sulfur in the natural gas, inert trace contaminants, and incomplete combustion of hydrocarbons. The final PSD permit for MBPP only allows the use of pipeline quality natural gas with a sulfur content of no more than 0.25 grains per 100 scf, and requires monthly analysis of the sulfur content of the natural gas combusted.

The EPA RACT/BACT/LAER Clearinghouse (RBLC)[6] provides a central online database of air pollution control technology determinations made to satisfy requirements for Reasonably Achievable Control Technology (RACT), Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER). We conducted recent searches (March 20, 2007) of the RBLC database for BACT determinations for natural gas-fired combined cycle turbines prior to the PSD permit proposal in May 2006 and recently as a result of public comments. The top BACT option for controlling PM_{10} from gas turbines is considered to be a combination of low or zero ash fuel (i.e., natural gas) and good combustion practices (See Table 3).

Recent BACT determinations for PM_{10} emissions from natural gas-fired turbines, reported by the EPA RBLC (Table 3) show that the proposed emissions limits of 11 and 13.3 lb/hr are comparable to facilities using similar natural gas turbines. A January 22, 2007 search of the California Air Resources Board (ARB) Statewide BACT Clearinghouse[7] reports three determinations for PM_{10} from $\geq$50 MW combined cycle natural gas-fired turbines. These emission limits range from 9 lb/hr (Sacramento Metropolitan Air Quality Management District (AQMD)), to 11.5 lb/hr (Feather River AQMD), to 17.2 lb/hr (San Joaquin Valley Air Pollution Control District), where the gas turbines from the power plant in

[6] http://www.epa.gov/ttn/catc/rblc/htm/welcome_eg.html
[7] http://www.arb.ca.gov/bact/bact.htm

the Feather River AQMD were most similar to the turbines proposed for use in the Modernization Project.

Table 3: Recent BACT Determinations from RBLC Database					
Facility	State	Date RBLC Determination last updated	PM_{10} without duct firing (lb/hr)	PM_{10} with duct firing (lb/hr)	Control Method Description
Rocky Mountain Energy Center, LLC	CO	5/8/06	7.6		Natural Gas Quality Fuel only and Good Combustion Practices
Crescent City Power [8]	LA	8/30/06	14.7	20.7	Clean Burning Fuel and Good Combustion Practices
Tracy Substation	CA	8/31/06		11.5	Best Combustion Practices
Forsythe Energy Plant [9]	NV	8/30/06	11.7	12.9	Clean Burning Low Sulfur Fuel and Good Combustion Practices
Berrien Energy, LLC	MI	1/4/06		19	Natural Gas and State of the Art Combustion Techniques
Duke Energy Hanging Rock Facility	OH	7/5/05	15	23.3	Low Sulfur Natural Gas

The BAAQMD BACT workbook shows that the achieved in practice BACT for PM_{10} from large ($\geq$ 40MW) combined cycle gas turbines is natural gas fuel with a sulfur content not to exceed 1.0 grain/100 scf, achieved through the exclusive use of PUC-regulated grade natural gas. The proposed PSD permit for the Modernization Project restricts the facility to the use of pipeline-quality natural gas with a sulfur content of no more than 0.25 grain/100 scf. Thus, the BACT determination made in 2000, which EPA updated for the proposed PSD permit in 2006, is still consistent with the most recent determinations.

2. *Duct burner firing increases emissions of PM_{10}, and should not be considered BACT. (# 12, 44, 46)*

[8] Emission limits from the RBLC report were inferred to be the total for 2 turbines. The 14.7 and 20.7 lb/hr emission limits represent limits per individual turbine.
[9] The RBLC database reports the emission limit as the total for 3 turbines. The 11.7 and 12.9 lb/hr emission limits represent limits per individual turbine.

Response to B-2:

The purpose of duct burner firing in the heat recovery steam generator (HRSG) is to elevate the turbine exhaust temperature, allowing production of additional power and higher steam cycle efficiency. As such, duct burners are components of the HRSG used to increase power generation from the steam turbines, and by definition, are not control technology to reduce air pollutant emissions. As a component of the combined cycle system, the gas turbines block units, associated with the Modernization Project, are subject to BACT emission limits with and without supplemental firing of the duct burners (11 lb/hr and 13.3 lb/hr, respectively). A survey of the EPA RBLC shows that two different emission limits are typically imposed on turbines based on the whether or not the duct burners are fired.

3. *The BACT analysis should require updated information by the owner/operator (given the extended delay since submission of the application) to address current BACT generally for CO, NOx, VOC, PM_{10}, and specifically as to the duct burning component of the project. In recent statements by Mr. Gary Willey of the APCD, Mr. Willey suggested that current BACT for greenhouse gases* * *would prevent duct burning because other turbines would not produce these greenhouse gases, as well as the excess PM_{10} emissions from duct burning, are commercially available, albeit at an increase up-front capital cost to the owner/operator.*

* *Mr. Willey has indicated that the APCD will consider any then applicable APCD required emissions limitations on greenhouse gases in connection with the APCD's final BACT review, as well as BACT for excessive PM_{10} emissions resulting from duct burning. (# 12)*

Response to B-3:

For a discussion of the BACT determination for PM_{10}, the only criteria pollutant subject to PSD review, please see our response to comment B-1. For a general discussion on duct burning, PM_{10}, and BACT, please see our response to comment B-2.

To the extent the comment raises issues relating to EPA's general permitting authority for CO_2 and other greenhouse gases ("GHGs"), EPA recognizes the importance of addressing the global challenge of climate change, and in light of the Supreme Court's decision in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), the Agency is working diligently to develop an overall strategy for addressing the emissions of CO_2 and other GHGs under the Clean Air Act. See 73 Fed. Reg. 44354, "Regulating Greenhouse Gas Emissions Under the Clean Air Act" (Advance Notice of Proposed Rulemaking) (July 30, 2008). However, EPA does not currently have the authority to address the challenge of global climate change by imposing limitations on emissions of CO_2 and other greenhouse gases in PSD permits.

While EPA has been implementing voluntary programs aimed at reducing greenhouse gases for several years, since the Supreme Court decision, EPA has been exploring the additional tools provided by the Clean Air Act to help us expand on the solid foundation we have built to achieve the global goal of reduced greenhouse gas emissions. In fact, EPA has recently issued an advanced notice of proposed rulemaking (ANPR) seeking public input regarding issues relating to "the specific effects of climate change and potential regulation of greenhouse gas emissions from stationary and mobile sources under the Clean Air Act." 73 Fed. Reg. 44354. While the ANPR is the first step in developing a regulatory strategy for addressing CO_2 and other GHG emissions under the CAA, the Agency has not yet proposed rules to regulate these emissions under the Act.

It is well established that "EPA lacks the authority to impose [PSD permit] limitations or other restrictions directly on the emission of unregulated pollutants." *North County Resource Recovery Assoc.*, 2 E.A.D. 229, 230 (Adm'r 1986). The Clean Air Act and EPA's regulations require PSD permits to contain emissions limitations for "each pollutant subject to regulation" under the Act. CAA § 165(a) (4); 40 CFR § 52.21(b) (12). In defining those PSD permit requirements, EPA has historically interpreted the term "subject to regulation under the Act" to describe pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant. *See* 43 Fed. Reg. 26388, 26397 (June 19, 1978) (describing pollutants subject to BACT requirements); 61 Fed. Reg. 38250, 38309-10 (July 23, 1996) (listing pollutants subject to PSD review); *In Re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 132 (EAB 1997); *Inter-power of New York*, 5 E.A.D. 130, 151 (EAB 1994); Memorandum from Jonathan Z. Cannon, General Counsel to Carol M. Browner, Administrator, entitled *EPA's Authority to Regulate Pollutants Emitted by Electric Power Generation Sources* (April 10, 1998); Memorandum from Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards, entitled *Definition of Regulated Air Pollutant for Purposes of Title V*, at 5 (April 26, 1993). In 2002, EPA codified this approach for implementing PSD by defining the term "regulated NSR pollutant" and clarifying that Best Available Control Technology is required "for each regulated NSR pollutant that [a major source] would have the potential to emit in significant amounts." 40 CFR § 52.21(j) (2); 40 CFR 52.21(b) (50).

In defining a "regulated NSR pollutant," EPA identified such pollutants by referencing pollutants regulated in three principal program areas -- NAAQS pollutants, pollutants subject to a section 111 NSPS, and class I or II substance under title VI of the Act-- as well as any pollutant "that otherwise is subject to regulation under the Act." 40 CFR 52.21(b)(50)(i)-(iv). As used in this provision, EPA continues to interpret the phrase "subject to regulation under the Act" to refer to pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant. Because EPA has not established a NAAQS or NSPS for CO_2, classified CO_2

as a title VI substance, or otherwise regulated CO_2 under any other provision of the Act, CO_2 is not currently a "regulated NSR pollutant" as defined by EPA regulations.

Although the Supreme Court decided the case cited by the commenter and held that CO_2 and other GHGs are air pollutants under the CAA, *see Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), that decision does not require the Agency to set emission limits for CO_2 and other GHGs in the Colusa Generating Station PSD permit. Notably, the Court did not hold that EPA was required to regulate CO_2 and other GHG emissions under Section 202, or any other section, of the Clean Air Act. Rather, the Court concluded that these emissions were "air pollutants" under the Act, and, therefore, EPA could regulate them under Section 202 (the provision at issue in the *Massachusetts* case), subject to certain Agency determinations pertaining to mobile sources.

EPA is currently exploring options for addressing GHG emissions in response to the Supreme Court decision. 73 Fed. Reg. 44354 (July 30, 2008). However, EPA has not yet issued regulations requiring control of CO_2 and other GHG emissions under the Act generally or the PSD program specifically. Accordingly, because CO_2 is not currently a pollutant regulated under the CAA, EPA cannot include emissions limitations for CO_2 (or other GHGs that are not otherwise regulated NSR pollutants) in the PSD permit for CGS. At this time, we believe that any action EPA might consider taking with respect to regulation of CO_2 or other GHGs in PSD permits or other contexts should be addressed through notice and comment rulemaking, as we have recently initiated by publishing the ANPR, allowing for a process which is public and transparent and based on the best available science. 73 Fed. Reg. 44354 (July 30, 2008).

4. *The BACT analysis should consider PM_{10} emissions from the potential use of cooling towers as an alternative to once-through sea water cooling. (# 12, 32, 34)*

Response to B-4:

Since the PSD permit application specifies the use of once-through seawater cooling with no resultant emissions of PM_{10}, a BACT determination for cooling tower options is not triggered. It is our understanding that the Central Coast Regional Water Quality Control Board ("Water Board") has postponed the issuance of a renewal permit under the National Pollutant Discharge Elimination System ("NPDES"). Although the public comment period for the proposed renewal NPDES permit for MBPP ended on January 26, 2007, the Water Board has placed the NPDES permit on an administrative extension, pending Water Board review of the recent EPA action on July 9, 2007 (72 FR 37107) to suspend the Phase II rule under section 316(b) of the Clean Water Act, regulating cooling water intake structures for existing large power plants. The suspension of the rule by EPA implements the decision from the 2nd Circuit U.S. Court of Appeals in Riverkeeper, Inc. v. EPA, issued January 25, 2007, remanding several provisions in the rule, including Best Technology Available determinations, restoration provisions, and performance standard ranges.

The EPA action retains a provision (40 CFR 125.90(b)) of the Phase II rule that requires permitting authorities to develop "Best Professional Judgment" controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. If the Water Board determines that once-through cooling by MBPP will not be allowed, and a different cooling method, such as dry cooling or cooling towers, is required, MBPP must apply for a revised PSD permit to include analyses of PM_{10} emissions from the cooling system, ensure that the new cooling system complies with all PSD requirements, including BACT, and specify revised PM_{10} emission limits in the new PSD permit.

Section C: Modeling and Ambient Air Quality Impact Analysis (AAQIR)

1. *The use of upper air data from Vandenberg Air Force Base is not appropriate. (# 12, 29-30, 44, 46)*

Response to C-1:

The upper air meteorological data from Vandenberg Air Force Base (VAFB) was used in the modeling analyses to determine atmospheric mixing heights, which impact the dispersion of pollutants (page 6.2-11). Vandenberg Air Force Base (VAFB) was the closest upper air meteorological station to Morro Bay (45 miles southeast). Given that marine climates influence mixing depths, the proximity of VAFB to the Pacific Ocean and to the project site makes the upper air data from Vandenberg appropriate for estimating mixing heights in Morro Bay.

The surface meteorological measurements were collected at the Morro Bay Power plant, and therefore are representative of the meteorological conditions at the proposed modification.

2. *Modeling scenarios examining a six-mile radius from the MBPP does not represent actual regional impacts of PM_{10} emissions. (# 12, 15, 44, 46)*

Response to C-2:

We agree that the PM_{10} emissions may have regional as well as local-scale impacts. Local-scale impacts typically result from primary emissions of PM_{10}, or PM_{10} emitted directly into the atmosphere. Regional impacts typically result from secondary PM_{10}, or PM_{10} formed in the atmosphere from chemical reactions. The MBBP's analyses considered both types of impacts. As required, the MBBP's source impact analysis predicted, through modeling, the local-scale ambient air quality impacts of the direct emissions of PM_{10} from the MBPP within the source's area of significant impact, as a result of the proposed modification. The analyses demonstrate that the proposed emissions increase from the modification will not cause or contribute to a violation of the NAAQS or PSD Class II increments for PM_{10}.

The MBBP's analysis of impacts beyond the local-scale impacts involved modeling the impacts of the source's emissions on the San Rafael Wilderness Class I area. The visibility analysis evaluates the visibility degradation that is caused by secondary particulate matter formed from NO_x and SO_x, as well as primary PM_{10}. The maximum impact on visibility in the San Rafael Wilderness Class I area meets the Federal Land Manager's criteria for the level of acceptable change. The air quality analysis demonstrates that the proposed modification will not cause or contribute to a violation of the NAAQS or PSD Class I increments for PM_{10} in the San Rafael Wilderness Class I.

3. *Meteorological conditions from 1994 – 1996 do not adequately address meteorological variability, including fog events, winter time inversions, and El Niño / La Niña phenomena. (# 9, 11-13, 27, 29, 35, 43-44, 46)*

Response to C-3:

The applicant reported in the Air Quality Analysis (page 6.2-49) that the meteorological conditions used in the modeling were obtained from data collected by PG&E at the MBPP site from 1994 – 1996. From the 1994 dataset, MBPP reported that the meteorological conditions expected to produce fog (relative humidity greater than 91.7%) were identified in 29% of all hours, representing roughly 51% of all days in 1994 experiencing at least one hour of fog, which is consistent with the long-term fog statistics from the National Weather Service Point Mugu station (page 6.2-58). The three years of real meteorological data were collected during actual conditions from 1994 – 1996, including foggy and non-foggy conditions and winter time inversions.

The three year data period from 1994 – 1996 was selected by the District to provide a variety of meteorological conditions (page 6.2-49). The District recommended use of data from 1994 – 1996 because they judged 1997 and 1998 to be highly unusual El Niño and La Niña years, and thus inappropriate to assure normal seasonal and short-term variations in meteorology (November 28, 2000 letter from Paul H. Allen III, SLOAPCD Supervising Air Quality Specialist to Kae Lewis, CEC Project Manager). Additionally, the Pacific Marine Laboratory (PMEL) of the National Oceanic and Atmospheric Administration (NOAA), part of the U.S. Department of Commerce, reported that weaker El Niño and La Niña years occurred in 1994 and 1995 – 1996, respectively[10]. Thus, data from 1994 – 1996 incorporated an El Niño year as well as two La Niña years. Therefore, because the meteorological data collected from 1994 – 1996 did incorporate fog events, and winter inversions, and El Niño Southern Oscillation (ENSO) events that were not as unusual as those experienced in 1997 – 1998, we determined that the data was representative of natural variability for Morro Bay.

4. *Assuming that the baseline emissions are estimated to be too high (Section A.2), the changes in emissions resulting from the project are larger than estimated and thus, do not adequately represent the impact of the project on the PSD increment and visibility. (# 12, 29, 31, 44, 46)*

Response to C-4:

This comment is confusing. The commenter seems to be implying that by overestimating the baseline emissions, the emissions increase and hence the projected impacts have been underestimated. The change in emissions resulting from the Modernization Project was **only** used to determine applicability of the Modernization Project to the PSD permitting program. The modeling analyses for this project submitted by the applicant (page 6.2-8) accounted for emissions from the proposed new turbines as well as from the existing boilers. Because the existing boilers will be shutdown as a result of the Modernization Project, by including the emissions from the existing boilers in the model, the impacts of the facility are modeled conservatively. Therefore, even if the baseline emissions were estimated to be too high, the impact of the project would not be underestimated, because the baseline emissions were not subtracted in the analysis. Thus, the applicant's analysis adequately estimates potential impacts from the facility.

5. *The additional impacts analysis states that MBPP operated without incident in proximity to agricultural uses. This does not adequately reflect the history of complaints by neighbors (# 1, 12, 29, 44, 46). The existence of historical complaints regarding fallout from the MBPP was highlighted in an article from the Fall 1967 issue of* Cry California: The Journal of California Tomorrow *(See Comment #29). The article describes an incident that occurred on May 20, 1966, where an increase in energy demand and natural gas consumption resulted in the combustion of fuel oil, rather than natural gas, by MBPP. The May 26, 1966 issue of the Morro Bay Sun newspaper reported resident complaints of damage to cars, house paint,*

[10] http://www.pmel.noaa.gov/tao/elnino/el-nino-story.html

clothes out to dry, flowers, and vegetables. The Cry California article cites the combustion of fuel oil as the cause of the fallout experienced in 1966. The article further stated that fuel oil combustion at the MBPP should be discontinued to avoid future fallout incidents (# 40).

<u>Response to C-5</u>:

The current Modernization Project proposes to remove the existing fuel oil tanks and replace the old fossil fuel oil-fired steam generators with combined cycle natural gas-fired turbines. Implementation of the proposed project will result in reduced emissions of NO_x, CO, and VOC, and an emissions increase of SO_2 that does not exceed the PSD significance threshold. Emissions of PM_{10} exceed the PSD significance threshold and are subject to the PSD regulations, requiring application of BACT, and impact analyses on ambient air (including national ambient air quality standards (NAAQS), PSD increments, visibility, soil, and vegetation). The modeling analyses have shown that PM_{10} emissions from the MBPP will comply with the NAAQS, the allowable PSD increment, and the allowable PSD Class I increment. Additionally, modeling has shown that visibility will not be adversely impacted by the Modernization Project, and the discontinued use of fuel oil by the MBPP will eliminate potential adverse impacts on soils and vegetation.

6. *The central and uncontested fact is that ground-level concentrations of particulate matter would rise 60% in Morro Bay, partly because of increased operating capacity and the reduction in stack height. (# 44, 46)*

<u>Response to C-6</u>:

EPA disagrees with the statement that it is a central and uncontested fact that ground level concentrations of particulate matter will increase by 60%. The change in *emissions* of PM_{10} resulting from the Modernization Project, calculated as the difference between the potential to emit (PTE) of the new turbines (203.2 tpy PM_{10}) and the baseline actual emissions of the existing boilers (127.2, tpy PM_{10}), is 76 tpy of PM_{10}. This increase of 76 tpy represents a 60% increase in potential PM_{10} *emissions*. Although potential emissions of PM_{10} from the facility will increase by 60%, the maximum modeled impact of the facility, estimated as the worst-case ground level concentration over a 24-hour averaging period (the averaging time for the National Ambient Air Quality Standard, or NAAQS), will increase by 24.2 micrograms of PM_{10} per cubic meter of air ($\mu g/m^3$). This represents a 42% increase over the background PM_{10} concentration (57 $\mu g/m^3$). It is important to note that 1) this modeled impact represents the maximum worst-case ground level concentration under fumigation conditions, and 2) the impact of the Modernization Project combined with the background PM_{10} concentration results in a total impact (81.2 $\mu g/m^3$)

that is 46% lower than the PM_{10} NAAQS of 150 μg/m^3. Therefore, the 60% increase in potential *emissions* results in a modeled maximum worst-case scenario increase in *ground level concentration* of 42%, which does not result in any violations of the PM_{10} NAAQS.

7. *The current applicable National Ambient Air Quality Standard (NAAQS) for PM_{10} cited in the AAQIR is out of date compared to a new NAAQS for PM_{10} adopted September 16, 1997. The new NAAQS should be implemented immediately. (#44, 46)*

Response to C-7:

The 24-hour and annual National Ambient Air Quality Standards for PM_{10} cited in the AAQIR (150 μg/m^3) were, and are up-to-date with the PM NAAQS promulgated on July 18, 1997 (68 FR 38652) and effective September 16, 1997. The 1997 standard for PM_{10} was revised from the previous standard to be based on the 3-year average of the 99th percentile of 24-hour PM_{10} concentrations at each monitor within an area. The numerical level of the standard 150 μg/m^3 was not changed in the 1997 rule. The annual PM_{10} standard was retained in the 1997 rule to be based on the 3-year average of the annual arithmetic mean PM_{10} concentration at each monitor in an area.

The 1997 PM Rule also created NAAQS for $PM_{2.5}$. However, due to the technical limitations associated with the monitoring, emissions estimation, and modeling of $PM_{2.5}$, EPA issued a guidance memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, to Regional Air Directors (October 13, 1997), regarding interim implementation of the New Source Review Requirements for $PM_{2.5}$. This guidance applies to the PSD program and recommends interim use of PM_{10} emissions as a surrogate for $PM_{2.5}$ until the PM2.5 final NSR implementation rule is promulgated. Thus, if emissions of PM_{10} are determined to be in compliance with BACT and the air quality impacts analyses, then the source can be considered to be in compliance for $PM_{2.5}$ emissions. This guidance was reaffirmed in an additional guidance memorandum from Stephen D. Page, Director, Office of Air Quality Planning and Standards to Regional Air Directors (April 5, 2005).

The modeled impacts of the Modernization Project on the 24-hour and annual average NAAQS are in compliance with the appropriate air quality standards for PM_{10}, promulgated July 18, 1997 and effective September 16, 1997. Therefore, the Modernization Project is in compliance with respect to both PM_{10} and $PM_{2.5}$ NAAQS.

Section D: PSD Permit Conditions

1. *Limits placed on PM_{10} emission rates are ineffective and unenforceable due to the lack of continuous in-stack monitoring of PM_{10}. (# 12, 23, 44, 46)*

<u>Response to D-1</u>:

Performance tests for PM_{10} emissions from the turbine exhaust stacks are required within 60 days after achieving maximum load, but no later than 180 days after initial startup, and annually thereafter. The PSD permit specifies that these tests must use the EPA-approved methods, Methods 5 and 202, for measuring PM_{10} emissions. Monthly samples of the natural gas combusted will monitor the sulfur content of the fuel, which is limited by the PSD permit to 0.25 gr/100 scf. Noncombustible trace constituents of fuel and the sulfur content of the fuel contribute to PM_{10} emissions from the natural gas-fired turbines. The use of low sulfur, pipeline quality natural gas fuel limits PM_{10} emissions to negligible amounts, as reported in AP 42, Chapter 3-1 (Stationary Gas Turbines) .

The reporting and record-keeping requirements regarding date, time, and total duration of startups and shutdowns of each turbine, and firing hours and fuel flow rates from each turbine and duct burner, will provide the necessary information to determine compliance with the annual PM_{10} emission limit based on the measured PM_{10} emission rate from the performance tests. PM_{10} continuous emission monitoring systems (CEMS) are typically used at coal-fired power plants to monitor primary PM_{10}. Emissions of PM_{10} from natural gas-fired power plants are dominated by condensable particulates (secondary PM_{10}), and the concentration of primary PM_{10} emissions from natural gas fired power plants are too low to be reliably measured with CEMS. Thus, annual performance testing using EPA Methods 5 and 202, and monthly testing of the fuel sulfur content, are the most reliable methods for ensuring compliance with PM_{10} emission limits.

Section E: Human and Ecosystem Health

1. *The Modernization Project, particularly the proposal to shorten the stack height, will pose a health threat to the local community as well as to bird populations that use the Morro Bay Estuary. (# 2-8, 14-16, 18-20, 22, 24-28, 32, 33, 35-36, 38-39, 42, 44-46)*

<u>Response to E-1</u>:

New stack heights of 145 feet (reduced from previous heights of 450 feet) were proposed by the applicant as a balance between engineering, public health, and aesthetic considerations. The new stack heights are in compliance with Good Engineering Practice (GEP) stack height, as defined in 40 CFR § 51.100 (ii), and the GEP provisions of 40 CFR § 51.118.

The change in air quality resulting from the increase in emissions at the facility was modeled with the shorter stack height of 145 feet. The maximum modeled impact of the facility, estimated as the worst-case ground level concentration over a 24-hour averaging period (the averaging time for the National Ambient Air Quality Standard, or NAAQS), will increase by 24.2 micrograms of PM_{10} per cubic meter of air ($\mu g/m^3$), which is lower than the PM_{10} increment of $30 \mu g/m^3$. The impact of the Modernization Project combined with the background PM_{10} concentration results in a total impact of 81.2 $\mu g/m^3$, which is lower than the PM_{10} NAAQS of 150 $\mu g/m^3$.

Because the ambient air quality analyses, based on worst-case ground level conditions using the new (lower) stack heights of 145 feet, showed that the Modernization Project would not result in concentrations that exceed the NAAQS or PSD increments, EPA finds the proposed stack height acceptable because public health and welfare remain protected.

2. *What will the impact of PM_{10} be on endangered species? (# 31)*

Response to E-2:

Pursuant to Section 7 of the Endangered Species Act ("ESA"), 16 USC §1536 and 50 CFR Part 402, EPA consulted with the National Marine Fisheries Service ("NMFS") and the Fish and Wildlife Service ("FWS"). In a letter dated May 17, 2002 from Rodney R. McInnis, Acting Regional Administrator for the NMFW Southwest Region, to Gerardo C. Rios, Chief of the EPA Region IX Air Permits Office, NMFS concluded that the Modernization Project is not likely to adversely affect federally threatened steelhead (*Oncorhynchus mykiss*).

The FWS issued a Biological Opinion ("BO") on the proposed project on May 23, 2003. The BO concluded that the Modernization Project is not likely to jeopardize the continued existence of the federally threatened California red-legged frog (*Rana aurora draytonii*), the endangered Morro shoulderband snail (*Helminthoglypta walkeriana*), or the tidewater goby (*Eucyclogobius newberryi*). The BO included reasonable and prudent measures ("RPMs") that are necessary to minimize impacts of the Modernization Project on these listed species. In a letter dated June 23, 2005, and submitted as an addendum to the PSD permit application, Duke Energy Morro Bay, LLC, from Randall J. Hickok, Vice President of California Assets, to Gerardo C. Rios, stated that the Modernization Project will implement the RPMs, terms, conditions, and reporting requirements contained in the BO into the project description. The Morro Bay Power Plant changed names in 2006 to LSP Morro Bay, LLC, and in 2007 to Dynegy Morro Bay, LLC. In letters submitted to Gerardo C. Rios on May 8, 2006 and May 30, 2007, LSP and Dynegy notified EPA of the name change, and reaffirmed the facility's previous commitments related to compliance with the PSD permit, including the requirements of the Biological Opinion.

Section F: Changes to the proposed PSD permit unrelated to comments received

1. The proposed PSD permit did not include an averaging time associated with the PM_{10} emission limit of 11 and 13.3 lb/hr. The final PSD permit states that each turbine is subject to the pound per hour PM_{10} emission limits on a six-hour rolling average basis.

2. The proposed PSD permit was modified to specify a required test method for the monthly fuel sulfur analyses. The permit will require use of ASTM D5504, one of the fuel sulfur test methods acceptable under NSPS Subpart KKKK. EPA or District approved alternative test methods for fuel sulfur content may be used in lieu of ASTM D5504 upon EPA approval.

3. Emissions of particulate matter (PM) are subject to PSD review when emitted at rates exceeding the significance level of 25 tons per year (tpy). Emissions of particulate matter less than 10 microns in aerodynamic diameter (PM_{10}) are regulated by PSD when emitted at rates exceeding the significance threshold of 15 tpy. Because a natural gas-fired power plant is not expected to emit course particulate matter (PM greater than 10 microns in aerodynamic diameter), emissions of PM are expected to be equivalent to emissions of PM_{10}. The PSD permit proposed in May 2006 addressed only PM_{10}, and did not address PM; however, PM is subject to PSD review because emissions will exceed 25 tpy. Since no distinct air quality standard exists for PM, and since emissions of PM and PM_{10} will be equivalent, PSD review for PM_{10} satisfies requirements for PSD review for PM. The final PSD permit was modified to replace references to "PM_{10}" with "PM/PM_{10}".