STOEL RIVES LLP
ATTORNEYS AT LAW

500 Capitol Mall Suite 1600
Sacramento, California 95814
main 916.447.0700
fax 916.447.4781
www.stoel.com

MELISSA A. FOSTER
Direct (916) 319-4673
mafoster@stoel.com

May 7, 2012

DOCKET	
11-AFC-1	
DATE	MAY 07 2012
RECD.	MAY 07 2012

VIA EMAIL

Mr. Eric Solorio, Siting Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Pio Pico Energy Center Project (11-AFC-1)
San Diego Air Pollution Control District's Final Determination of Compliance

Dear Mr. Solorio:

On behalf of Applicant Pio Pico Energy Center LLC, please find herein for docketing the San Diego Air Pollution Control District Final Determination of Compliance ("FDOC") for the Pio Pico Energy Center Project. A copy of the FDOC will be served to all parties pursuant to the enclosed proof of service.

Very truly yours,

Melissa A. Foster

MAF:jmw
Enclosures
cc: Proof of Service List

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

APPLICATION FOR CERTIFICATION FOR THE *PIO PICO ENERGY CENTER, LLC*	**Docket No. 11-AFC-1 PROOF OF SERVICE (Revised 3/20/12)**

Pio Pico Energy Center, LLC
Applicant's Submittal of San Diego Air Pollution Control District's Final Determination of Compliance (May 7, 2012)

APPLICANT

Gary Chandler, President
Pio Pico Energy Center
P.O. Box 95592
South Jordan, UT 84095
grchandler@apexpowergroup.com

David Jenkins, Project Manager
Pio Pico Energy Center, LLC
1293 E. Jessup Way
Mooresville, IN 46158
djenkins@apexpowergroup.com

APPLICANT'S CONSULTANTS

Maggie Fitzgerald
Sierra Research
1801 J Street
Sacramento, CA 95811
MFitzgerald@sierraresearch.com

COUNSEL FOR APPLICANT

John A. McKinsey
Melissa A. Foster
Stoel Rives, LLP
500 Capitol Mall, Suite 1600
Sacramento, CA 95814
jamckinsey@stoel.com
mafoster@stoel.com

INTERESTED AGENCIES

California ISO
e-mail service preferred
e-recipient@caiso.com

PETITIONERS

April Rose Sommer
Attorney for Rob Simpson
P.O. Box 6937
Moraga, CA 94570
e-mail service preferred
aprilsommerlaw@yahoo.com

ENERGY COMMISSION-DECISIONMAKERS

CARLA PETERMAN
Commissioner and Presiding Member
cpeterma@energy.state.ca.us

KAREN DOUGLAS
Commissioner and Associate Member
e-mail service preferred
kldougla@energy.state.ca.us

Raoul Renaud
Hearing Adviser
rrenaud@energy.state.ca.us

Jim Bartridge
Presiding Member's Adviser
jbartrid@energy.state.ca.us

Galen Lemei
Associate Member's Adviser
e-mail service preferred
glemei@energy.state.ca.us

ENERGY COMMISSION STAFF

Eric Solorio
Siting Project Manager
esolorio@energy.state.ca.us

Kevin W. Bell
Staff Counsel
kwbell@energy.state.ca.us

Eileen Allen
Commissioners' Technical Advisor for Facility Siting
e-mail service preferred
eallen@energy.state.ca.us

ENERGY COMMISSION – PUBLIC ADVISER

Jennifer Jennings
Energy Commission Public Adviser
e-mail service preferred
publicadviser@energy.state.ca.us

DECLARATION OF SERVICE

I, Judith M. Warmuth, declare that on May 7, 2012:

☐ I deposited copies of the aforementioned document and, if applicable, a disc containing the aforementioned document in the United States mail at 500 Capitol Mall, Suite 1600, Sacramento, California 95814, with first-class postage thereon fully prepaid and addressed to those identified on the Proof of Service list herein and consistent with the requirements of California Code of Regulations, Title 20, sections 1209, 1209.5, and 1210.

OR

☒ I transmitted the document(s) herein via electronic mail only pursuant to California Energy Commission Standing Order re Proceedings and Confidentiality Applications dated November 30, 2011. All electronic copies were sent to all those identified on the Proof of Service list herein and consistent with the requirements of California Code of Regulations, Title 20, sections 1209, 1209.5, and 1210.

OR

☐ On the date written above, I placed a copy of the attached document(s) in a sealed envelope, with delivery fees paid or provided for, and arranged for it/them to be delivered by messenger that same day to the office of the addressee, as identified on the Proof of Service list herein and consistent with the requirements of California Code of Regulations, Title 20, sections 1209, 1209.5, and 1210.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

Judith M. Warmuth

Judith M. Warmuth

AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

May 4, 2012

ERIC SOLORIO
PROJECT MANAGER
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO CA 95814

Dear Mr. Solorio:

Please find enclosed the District's Final Determination of Compliance for the for Pio Pico Energy Center LLC's proposed development of the Pio Pico Energy Center (District Application No. APCD2010-APP-001251), an approximately 300 megawatt electrical generating facility consisting of three simple-cycle natural-gas-fired combustion turbine generators, to be located at 7363 Calzada de la Fuente, Otay Mesa, CA 92154. .

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 including all applicable state and federal requirements that the District enforces. The proposed permit incorporates conditions necessary to ensure compliance with all these requirements.

Should you have any questions regarding this matter, please contact Steven Moore at (858) 586-2750.

Sincerely,

Thomas Weeks

THOMAS WEEKS
Chief of Engineering

Enclosures

ID#: APCD-2010-SITE-00471

10124 Old Grove Road • San Diego • California 92131 • (858) 586-2600
FAX (858) 586-2601 • Smoking Vehicle Hotline • 1-800-28-SMOKE

FINAL
DETERMINATION OF COMPLIANCE

PIO PICO ENERGY CENTER

SAN DIEGO AIR POLLUTION CONTROL DISTRICT

Application Number APCD2010-APP-001251

May 4, 2012

Project Engineer Camqui Nguyen

Senior Engineer: Steven Moore

Application Numbers: APCD201-APP-001251

Site ID Number: APCD2010-SITE-00471
Fee Schedule: 20F
BEC: New

APPLICATION INFORMATION

Owner / Operator: Pio Pico Energy Center, LLC

Mailing Address: PO Box 95592
South Jordan, UT 84095

Equipment Address: 7363 Calzada de la Fuente
Otay Mesa, CA 92154

Contact: Gary Chandler
Company: Pio Pico Energy Center LLC
Position: President
Phone Number: (801) 253-1278
Fax Number:

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APPENDICES

I. PROJECT DESCRIPTION

Pio Pico Energy Center LLC (Applicant) proposes to develop the Pio Pico Energy Center (PPEC). This project is a simple-cycle turbine electrical generating facility with a total nominal base load net power output of 300 MW. The PPEC will utilize three GE LMS100 intercooled natural gas fired combustion turbine generators (CTGs), each equipped with water injection, a selective catalytic reduction (SCR) system and an oxidation catalyst system. The nominal net power output is 100 megawatts (MW) with a corresponding heat input of 903 million British thermal units per hour (MMBtu/hr) per turbine (at 63 ^{o}F ambient temperature and based on the higher heating value of natural gas fuel). The combustion turbines are also equipped with evaporative coolers that can be used to cool the inlet air to each turbine to increase power during periods of high ambient temperature. Each CTG is followed by a selective catalytic reduction (SCR) system to reduce oxides of nitrogen (NOx) emissions and an oxidation catalyst to control carbon monoxide (CO) and volatile organic compound (VOC) emissions in the turbine exhaust. Intercooling is accomplished for each turbine with an external heat exchanger using water to cool the interstage compressed air from the turbine. The water exiting the heat exchanger is in turn cooled in a hybrid dry/wet cooling system utilizing dry cooling with ambient air followed by a forced draft wet surface to air cooler (WSAC), which is similar to a cooling tower except the process water is segregated from the wet surface cooling.

The PPEC is subject to the approval of the California Energy Commission (CEC) because the proposed power plant has a nominal rating greater than 50 MW. The Applicant filed an application for certification (AFC) with the CEC in February 2011 (CEC Docket No. 11-AFC-01). The San Diego County 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.

The PPEC is proposed to be located on an unincorporated industrial area in Otay Mesa in San Diego County. The project location is on the southeast corner of the Alta Road and Calzada de la Fuente intersection, west of the existing Otay Mesa Generating Project.

The project will be fueled by natural gas, which will be supplied by the San Diego Gas and Electric (SDG&E) 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

The Applicant has proposed to construct and operate the following equipment at this facility under Application No. APCD2010-APP-001251:

> Three nominal 100 MW natural-gas fired simple-cycle intercooled GE LMS100 combustion turbine generators, serial number to be determined, each equipped with an evaporative cooler for the inlet air; a compressor intercooler utilizing a heat exchanger and a common partial dry cooling system with a wet surface air cooler; a continuous emission monitoring system (CEMS) for NOx and CO; a data acquisition and handling system (DAHS) to record key operational parameters; water injection and a selective catalytic reduction system (SCR), and an oxidation catalyst.

III. PROCESS DESCRIPTION

The PPEC consists of three CTGs. Each CTG consists of a stationary combustion turbine generator and associated auxiliary equipment. 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. Each CTG provides a nominal 100 MW of electricity with the combustion turbine at full load.

The chosen simple-cycle CTG incorporates a compressor intercooler and increased firing temperature to produce power at higher efficiency than other simple-cycle CTGs. Filtered and cooled air drawn into the combustion turbine is compressed and cooled, then compressed to higher pressure before being combusted in the turbine combustor. Water is injected into the combustor to temper the combustion temperature and to reduce thermal NOx production.

The one-hour averaged NOx emission concentration of the combustion gases exiting the turbine is controlled to 2.5 parts per million by volume on a dry basis (ppmvd) averaged over one hour and corrected to 15 percent oxygen (at 15% O_2) by a combination of the water injection in the CTG and the SCR system. 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 exhaust stack, is limited to 5.0 ppmvd at 15% O_2 averaged over one hour. The CTG is also equipped with an oxidation catalyst to control CO emissions leaving the exhaust stack to 4.0 ppmvd and VOC emissions to 2.0 ppmvd as methane, both at 15% O_2 averaged over one hour. Exhaust from each CTG will be discharged from an individual 14.5-foot diameter stack proposed to be 100-foot tall.

A partial dry-cooling system (PDCS), which is a closed-looped two-stage cooling system is used for the plant. In this system, heat rejected from the turbine compressor and the lube oil system is cooled using ambient air in a dry-cooling system, followed by a closed-loop WSAC for additional cooling by evaporating water from the surface of a heat exchanger tubes enclosing the process water.

Recycled water supplied by the Otay Water District will be used for cooling system makeup, the WSAC, CTG water injection, and CTG inlet air evaporative cooler makeup. Makeup water for the cooling water system will be stored in a 500,000-gallon raw water storage tank. This raw water will be treated with water-conditioning chemicals to minimize corrosion, bio-fouling, and formation of mineral scale. Demineralized water used for CTG water injection will be recycled water that is filtered, demineralized and stored in a 240,000 gallon tank.

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 exhaust 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.

The PPEC will operate under a 20-year Power Purchase Agreement (PPA) with SDG&E under the Request for Offer (RFO) authorized by California Public Utilities Commission (CPUC). To meet the objectives of the RFO, the PPEC will be capable of operations at a 46% capacity factor and at greater than 98% availability.

The basic operational modes primarily affecting emissions are startups, shutdowns, 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 thirty-minute time period starting when the fuel flow begins. Shutdown is defined as the eleven-minute period preceding the moment at which fuel flow ceases. Emissions during startups and shutdown are significantly higher than during steady state operation. The Applicant estimates that there will be up to 500 typical startups per turbine per year and up to 500 typical shutdowns per turbine per year. Maximum annual emissions are calculated based on 500 hours with a startup, 500 hours with a shutdown, and 3,335 hours per year at full-load operation under average conditions for all three CTGs.

IV. EMISSION ESTIMATES

COMBUSTION TURBINE GENERATOR EMISSIONS—STANDARD OPERATIONS

MAXIMUM HOURLY EMISSIONS

Project emissions of NOx, CO, sulfur oxides (SOx), VOCs, 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 the FDOC permit conditions. The startup and shutdown, emission rates were provided by the turbine manufacturer. For normal operations, emission rates for NOx, CO, and VOCs are calculated based on emission concentration limits (in ppmvd at 15% O_2) in the FDOC permit conditions and exhaust flow rates in dry standard cubic feet per hour (dscfh) at an average ambient temperature of 63°F:

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

Operation at the average ambient temperature of 63 °F provides the highest emissions among the 6 turbine operating scenarios considered. The FDOC conditions limit peak hourly and annual emissions based on this operating scenario.

Maximum hourly emissions of SOx are calculated based on the fuel heat input in 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 (CPUC) standard for pipeline natural gas. Emissions of PM10 are calculated based on vendor supplied guaranteed emission rates with an additional margin 0.5 pounds per hour. Table 1a presents the hourly emission rates in pounds per hour (lbs/hr) for all five criteria pollutants at average ambient temperature (63 °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 Single Turbine Emission Rates During Normal Operation		
Pollutant	Concentration, ppmvd @15% O_2	Emission Rate at Average Peak Ambient Temperature, lb/hr
NOx	2.5 (1- hour average)	8.18
CO	4.0 (1-hour average)	7.97
VOCs	2.0 (1-hour average)	2.28
PM10	N/A	5.5
PM2.5	N/A	5.5
SOx	N/A	1.9

During a CTG startup hour, there may be approximately 30 minutes of emission rates higher than emissions during normal operation. Therefore, typical hourly emission rates during startup are based on 30 minutes of high emission levels followed by 30 minutes of normal operation emission levels. During a typical CTG shutdown hour, there are approximately 49 minutes of normal operation followed by 11 minutes of higher emission levels. Therefore, typical hourly emission rates during shut down are based on 49 minutes of normal operation emission levels followed by 11 minutes of higher emission levels. For any hour when both a typical startup and a shutdown occur, there would be 30 minutes of startup emissions, 19 minutes of normal emissions and 11 minutes of shutdown emissions. Normal operation emissions were assumed to correspond to those at average ambient temperature in calculating the hourly emission rates.

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 Single Turbine Emission Rates During Startup and Shutdown			
Pollutants	Startup Emissions, lbs/hr	Shutdown Emissions, lbs/hr	Startup and Shutdown, lbs/hr
NOx	26.63	12.68	31.13
CO	21.84	53.51	67.38
VOCs	5.81	4.86	8.39
PM10	5.5	5.5	5.5
PM2.5	5.5	5.5	5.5
SOx	<1.9	<1.9	<1.9

<u>Maximum Daily Emissions</u>

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 4 hours include a startup, 4 hours include a shutdown, and 16 hours for maximum normal operation at peak average ambient temperature, as follows:

Daily emissions = (startup emissions, lbs/hr) x (4 hours/day) + (shutdown emissions, lbs/hr) x (4 hours/day) + (normal operation emissions, lbs/day) x (16 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 Three Turbines lbs/day
NOx	288.12	864.36
CO	428.92	1286.76
VOCs	79.16	237.48
PM10	132	396
PM2.5	132	396
SOx	45.6	136.8

Maximum Annual Emissions

Maximum annual emissions for the combustion turbines are estimated based on the assumption that each turbine operates up to 4335 hours per year, of which 500 hours are with a startup, 500 hours are with a shutdown, and 3335 hours for maximum normal operation at average ambient temperature, as follows:

Annual emissions = (startup emissions, lbs/hr) x (500 hours/year) + (shutdown emissions, lbs/hr) x (500 hours/year) + (normal operation emissions, lbs/day) x (3335 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 Three Turbines, tons/yr
NOx	23.47	70.41
CO	32.13	96.39
VOCs	6.47	19.41
PM10	11.92	35.76
PM2.5	11.92	35.76
SOx	1.37	4.12

Note that the expected annual SOx emissions in Table 1d are based on 0.25 grams of sulfur per per100 standard cubic feet of natural gas to represent the historical average sulfur content of natural gas in San Diego. This is significantly less than the PUC limit for sulfur content of natural gas of 0.75 grams of sulfur per 100 standard cubic feet of natural gas. The Applicant has agreed to accept a permit condition to limit total annual SOx emissions to the 4.12 tons per year corresponding to the lower historical average sulfur content.

WET SURFACE AIR COOLER EMISSIONS

The wet surface air cooler (WSAC) is part of the plant partial dry-cooling system (PDCS) installed to remove the plant waste heat. Water droplets from the WSAC discharge are a source of PM10 emissions. For the PPEC, a WSAC consisting of 12 cells is proposed. The cooler will circulate a maximum total of 23,520 gallons per minute or 11.755 x 10^6 lbs/hour of water. The maximum total dissolved solids (TDS) level is 5,600 ppm, and the guaranteed drift rate is 0.001%. PM10 emission rates from the WSAC are:

PM10 (lbs/hour) = (TDS concentration) x (drift loss of circulating water) x (lbs water/hour)

= (5,600 x 10^{-6}) x (0.00001) x (11.755 x 10^6)

= 0.658 lbs/hour

PM10 (lbs/day) = 0.658 lbs/day x 24 hours/day

= 15.799 lbs/day

PM10 (tons/year) = 0.658 lbs/hour x 4335 hours/year x (1 ton/2000 lbs)

= 1.426 tons/year

PROJECT EMISSIONS—STANDARD OPERATIONS

Standard operations are those operations occurring after the commissioning period for a turbine (see below). Total emissions from the project include emission from three combustion turbines and emissions from the WSAC. Table 2a and 2b present the estimated maximum project total daily and annual emissions in pounds per day and tons per year, respectively.

Table 2a – Maximum Project Total Daily Emissions

Pollutant	Turbines Total Daily Emissions, lbs/day	WSAC Daily Emissions, lbs/day	Project Total Daily Emissions, lbs/day
NOx	864.36	—	864.36
CO	1286.76	—	1286.76
VOCs	237.48	—	237.48
SOx	136.8	—	136.8
PM10	396	15.80	411.80
PM2.5	396	15.80	411.80

Table 2b – Maximum Project Total Annual Emissions			
Pollutant	Turbines Total Annual Emissions, tons/yr	WSAC Annual Emissions, tons/yr	Project Total Annual Emissions, tons/yr
NOx	70.41	—	70.41
CO	96.39	—	96.39
VOCs	19.41	—	19.41
SOx	4.1	—	4.1
PM10	35.76	1.43	37.19
PM2.5	35.76	1.43	37.19

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

COMBUSTION TURBINE GENERATOR EMISSIONS—COMMISSIONING PERIOD

Following construction of the power plant and prior to full commercial operation, the combustion turbine generators, emission control equipment, and other equipment will be tested and tuned. During this commissioning period, because the CTG burners may not yet be tuned for optimal emissions and because the postcombustion control equipment will not yet be in full operation, emissions from the plant will be higher than standard operating emissions. Each turbine is expected to operate 112 hours during this commissioning period, which includes startups and shutdowns, hours of operation at different load levels, and operation 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 3a presents the expected commissioning maximum hourly emission rates.

Table 3a –Maximum Turbine Hourly Emissions During Commissioning		
Pollutants	Single Turbine Emissions, lbs/hr	Combined Turbine Emissions, lbs/hr
NOx	50	150
CO	75	225
VOCs	5	15
SOx	0.6	1.8
PM10	5.5	16.5
PM2.5	5.5	16.5

For a single combustion turbine, expected maximum daily emissions during commissioning are based on the peak emission day for each pollutant as forecast from the projected commissioning schedule. Table 3b presents the maximum daily commissioning emissions. The entire commissioning period may take up to 112 hours for each turbine to allow time for reviewing test and tuning information and making operational adjustments to the combustion turbines and associated plant equipment.

Table 3b – Maximum Daily Emissions During Commissioning		
Pollutants	Single Turbine Emissions, lbs/day	Combined Turbine Emissions, lbs/day
NOx	1200	3600
CO	1800	5400
VOCs	120	360
SOx	25.2	75.6
PM10	132	396
PM2.5	132	396

Total commissioning emissions are based on turbine vendor projected emission data for the entire commissioning period. Table 3c presents total commissioning emissions.

Table 3c – Total Annual Turbine Commissioning Emissions		
Pollutants	Single Turbine Emissions, tons	Combined Turbine Emissions, tons
NOx	2.8	8.4
CO	4.2	12.6
VOCs	0.28	0.84
SOx	0.05	0.15
PM10	0.31	0.93
PM2.5	0.31	0.93

PROJECT EMISSIONS—COMMISSIONING PERIOD

For the combustion turbines' first year of operation during which both commissioning operations and standard operations take place, PPEC will operate in such a way to ensure total combined annual emissions from all three turbines do not exceed the emissions shown in Table 1d.

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/year)
PM10	100
NOx	50
VOCs	50
SOx	100
CO	100
Lead (Pb)	100

Major source status is only relevant for pollutants for which the District does not attain an applicable 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. Based on its potential to emit, the PPEC is a major stationary source for NOx.

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

Although the PPEC is a fossil-fuel-fired electrical generating plant with a heat input rating greater than 250 MMBtu/hr, it is not a steam generating plant. Therefore PSD Stationary Source status is defined by an aggregate potential to emit one or more air contaminants in amounts equal to or greater than any of the following emission rates under District rules and under federal rules except for the recently promulgated federal PS7D requirements for greenhouse gases:

Air Pollutant	Emission Rates (tons/year)
PM10	250
PM2.5	250
PM	250
NO_2	250
VOCs	250
SO_2	250
CO	250
Lead (Pb)	250

(Note that District Rule 20.1 does not explicitly address PM2.5 nor does it address particulate matter of all sizes (PM). However, PM2.5 is addressed as subset of PM10).

As of July 1, 2011, federal PSD requirements apply to a new stationary source that emits more than 100,000 ton per year of greenhouse gases (GHGs). PPEC's potential to emit exceeds this federal PSD stationary source threshold for GHGs. Consequently, PPEC submitted an application to EPA for a federal PSD permit in April, 2011.

The District is currently not delegated to implement federal PSD by EPA nor does it have a PSD rule that has been approved by EPA. Hence, PSD permitting for federal PSD is solely the responsibility of EPA at the current time. The District's New Source Review (NSR) rules do contain provisions for PSD that the District implements locally. The proposed project's compliance with these provisions is evaluated in the FDOC in accordance with District Rules and Regulations. It is worth noting that, although the District PSD provisions reflect many elements of federal PSD, there are some differences. In particular, the District currently has no authority in its Rules and Regulations to address greenhouse gases (GHGs).

While the District may seek federal delegation of the PSD permitting program in the future, at this time the federal PSD permit remains a separate matter under federal jurisdiction and permitting by the EPA. Thus, EPA would currently be the agency to issue a PSD permit, with no effect on the validity of the District's Final Determination of Compliance (FDOC).

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

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 PPEC three CTGs will be the first emission units operating at this stationary source. Therefore, the Contemporaneous Emission Increase for the PPEC stationary source is the same as the project potential to emit.

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

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, VOCs, 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 new major source or a major modification.

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 PPEC constitutes a major stationary source for NOx. For the PPEC combustion turbines, BACT applies for VOCs, SOx, PM10 and PM2.5 as a subset of PM10 emissions because their emissions are more than 10 pounds per day.

In summary, based on emission estimates, LAER is triggered for NOx and, for the combustion turbines, BACT is triggered for VOCs, SOx, and PM10.

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

The turbine vendor has guaranteed a NOx emission level of 2.5 ppmvd at 15% oxygen with water injection for the CTG and with the SCR add-on air pollution control system to control NOx installed. The Applicant has proposed a NOx emission limit of 2.5 ppmvd averaged over one hour as BACT and LAER during normal operations.

The District consulted the EPA BACT / LAER Clearinghouse, other air district decisions and BACT Guidelines, and ARB for recent BACT/LAER determinations. A number of simple-cycle power plants of comparable size were permitted with NOx at 2.5 ppmvd, averaged over one hour. The District examined the following projects with NOx emission limits at 2.5 ppmvd at 15% oxygen:

- The Panoche Energy Center is permitted by the San Joaquin Valley Unified Air Pollution Control District [CEC Final Approval issued on December 19, 2007 (CEC Docket No. 06-AFC-5)] and has been in operation since 2009. This plant has four GE LMS100 combustion turbines similar to the ones proposed for the PPEC. This plant has been in compliance with a 2.5 ppmvd NOx limit averaged over one hour, excluding startups and shutdowns.

- The Starwood Power Project is permitted by the San Joaquin Valley Air Pollution Control District [CEC Final Approval issued on January 16, 2008 (CEC Docket No. 06-AFC-10)] and has been in operation since 2009. This 120 MW plant consisting of two Pratt & Whitney FT8-3 SwiftPac CTGs has been in compliance with a 2.5 ppmvd NOx limit averaged over one hour, excluding startups and shutdowns.

- The Orange Grove Energy Center is permitted by the San Diego Air Pollution Control District [CEC Final Approval was issued on April 8, 2009 (CEC Docket No. 08-AFC-4)) and has been in operation since 2010. This plant consisting of two 49.5 MW GE LM 6000 PC SPRINT CTGs has been able to comply with a 2.5 ppmvd NOx limit averaged over one hour, excluding startups and shutdowns.

- The Mariposa Peaker Project is permitted by the Bay Area Air Quality Management District [CEC Final Approval issued on May 18, 2011 (CEC Docket No. 2009-AFC-3C)] and is currently under construction. This approximately 200 MW plant consisting of four GE LM6000-PC SPRINT CTGs is permitted with a 2.5 ppmvd NOx limit averaged over one hour, excluding startups and shutdowns.

- The CPV Sentinel, LLC project is permitted by the South Coast Air Quality Management District [CEC Final Approval was issued on December 1, 2010 (CEC Docket No. 2007-AFC-3C)] and is currently under construction. This plant consists of eight GE LMS100 CTGs similar to the ones proposed for the PPEC. This plant is permitted with a 2.5 ppmvd NOx limit averaged over one hour, excluding startups and shutdowns.

Based on the above information, the District has determined that BACT for NOx should be 2.5 ppmvd at 15% oxygen, averaged over one hour for normal operation with exclusions for startups and shutdowns. 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 2.5 ppmvd NOx at 15% oxygen averaged over one hour is considered by the District to be the current most stringent emission limit for simple-cycle combustion turbines that is achievable. Therefore, this standard also applies as LAER for NOx for such turbines.

As proposed by the Applicant, the PPEC combustion turbines will be equipped with water injection for the combustors and a SCR add-on emission control system that in combination are designed to achieve 2.5 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 water injection for the combustors and SCR on large (greater than 50 MW) natural-gas-fired simple-cycled combustion turbines. A continuous emission monitoring system (CEMS) and annual source testing will be used to confirm compliance with this emission 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 with the oxidation catalyst add-on air pollution control system, which is the only post-combustion technology currently available to control CO, VOCs, and toxic emissions. The Applicant has proposed a VOC emission limit of 2.0 ppmvd as methane at 15% oxygen averaged over one hour as BACT for normal operations. The limit is to be achieved by use of an oxidation catalyst system.

The District consulted the EPA BACT / LAER Clearinghouse, other air district decisions and BACT Guidelines, and ARB for recent BACT/LAER determinations. The District examined the following simple-cycle combustion turbine projects with VOC emission limits of 2.0 ppmvd or less measured as methane at 15% oxygen:

- The Panoche Energy Center is permitted by the San Joaquin Valley Unified Air Pollution Control District [CEC Final Approval was issued on December 19, 2007 (CEC Docket No. 06-AFC-5)] and has been in operation since 2009. This plant has four GE LMS100 combustion turbines similar to the ones proposed for the PPEC. This plant has been in compliance with a 2.0 ppmvd VOC limit averaged over three hours, excluding startups and shutdowns

- The Starwood Power Project is permitted by the San Joaquin Valley Air Pollution Control District [CEC Final Approval was issued on January 16, 2008 (CEC Docket No. 06-AFC-10)] and has been in operation since 2009. This approximately 120 MW plant consisting of two Pratt & Whitney FT8-3 SwiftPac CTGs has been in compliance with a 2.0 ppmvd VOC limit averaged over three hours, excluding startups and shutdowns.

- The Orange Grove Energy Center is permitted by the San Diego Air Pollution Control District [CEC Final Approval was issued on April 8, 2009 (CEC Docket No. 08-AFC-4)] and has been in operation since 2010. This plant consists of two 49.5 MW GE LM6000-

PC SRINT CTGs has been able to comply with a 2.0 ppmvd VOC limit averaged over one hour, excluding startups and shutdowns.

- The El Cajon Energy Project consisting of one 49 MW GE LM6000 PC SPRINT CTG is permitted by the San Diego Air Pollution Control District in 2010 with VOC limit of 2.0 ppmvd averaged over one hour. This plant demonstrated compliance with this limit through initial compliance testing in 2010.

- The CPV Sentinel, LLC project was permitted in the South Coast Air Quality received CEC Final Approval on December 1, 2010 (CEC Docket No. 2007-AFC-3C), and is currently under construction. This plant consists of eight GE LMS100 CTGs similar to the ones proposed for the PPEC. This plant is permitted with a VOC limit of 2.0 ppmvd averaged over one hour, excluding startups and shutdowns.

- The Mariposa Energy Project (MEP) in the Bay Area Air Quality Management District received CEC Final Approval on December 1, 2010 (CEC Docket No. 09-AFC-03), and is currently under construction. This plant consists of four GE LM6000 PC SPRINT CTGs. This plant is permitted with a 1.0 ppmvd VOC limit averaged over one hour, excluding startups and shutdowns. The limit is based on an engineering and cost-effectiveness analysis by the applicant.

The District notes that recent successive District compliance tests on two currently permitted simple-cycle LM6000 PC SPRINT turbines equipped with oxidation catalysts gave the following results:

VOC Concentration, ppmvd Measured as Methane at 15% O_2		
Test Method	Turbine A	Turbine B
Method[a] 18	< 0.09[c]	1.16[d]
Methods[b] 25A and 18	0.98	0
Methods[b] 25A and 18	0.67	1.97

[a]EPA Method 18 measures a selection of expected VOCs with gas chromatography.
[b]All organic compounds are measured, unspeciated, with EPA Method 25A and then methane and ethane, which are not VOCs, are measured by EPA Method 18 and subtracted from the total.
[c]One half the detection limit for the sum of VOCs measured is given because all species were below the detection limit.
[d]Approximately 0.10 ppmvd of the measured value were species that were not detected and so had concentrations of one half of the detection limit assigned.

Based on the above information, the lowest VOC limit that has been achieved in practice (proven in the field) is 2.0 ppmvd. Determinations of compliance for an emission limit of 1.0 ppmvd or less may be sensitive to the test method, test procedures, and detection limits used to verify compliance.

In addition, there is the potential for the PPEC facility to combust fuel derived from imported liquefied natural gas, which can have a higher VOC content than the natural gas fuel historically used in San Diego and would be expected to have higher VOC emissions compared than the historical gas supply. Compliance with a 1.0 ppmvd limit when combusting higher VOC content natural gas has not been demonstrated, and it may not be technologically feasible to achieve a 1.0 ppmvd limit when combusting such gas. It should be noted that the applicant's vendor considered natural gas with higher VOC amounts when guaranteeing controlled emission rates.

Although the District may investigate further, based on the above information and considerations, the District has determined that, at this time, BACT for the PPEC combustion turbines is a 2.0 ppmvd VOC limit, measured as methane at 15% O_2 over a one-hour averaging period for normal operation with exclusions for startups and shutdowns. An initial source test will be used to confirm compliance with the limit. 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 the limit using the CEMS data for CO on a one-hour basis. Compliance will be determined based on both source test data and a surrogate relationship with CO because CEMS technology is not yet available for VOCs.

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

Startups are limited to 30 minutes and shutdowns to 11 minutes. These times are consistent with, or more stringent than the Orange Grove Energy project permitted by the San Diego Air Pollution Control District [CEC Final Approval issued on April 8, 2009 (CEC Docket No. 08-AFC-4)], and the El Cajon Energy Project permitted by the San Diego Air Pollution Control District in 2010, both of which are simple-cycle turbines. The CPV Sentinel LLC project is permitted by the South Coast Air Quality Management District in 2010 [CEC Final Approval issued on December 1, 2010 (CEC Docket No. 2007-AFC-3C)]. This project consists of eight GE LMS 100 CTGs similar to the ones proposed for the PPEC and is limited to 25 minutes for startup and 10 minutes for shutdown. Since this project is still under construction, these lower time limits for startups and shutdowns are not considered achieved in practice. Also, the NOx emission limit for startup for the CPV Sentinel LLC project is 29.54 lbs/hour, while the startup emission limit for the PPEC 26.63 lbs/hour.

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.

Table 5a presents the mass emissions limits during startup and shutdown

Table 5a – Emission Limits During Startup (SCR to Operate as Soon as Feasible) and Shutdown		
Pollutants	Startup Emissions, pounds per event	Shutdown Emissions, pounds per event
NOx	22.54	6.00
CO	17.86	47.00
VOCs	4.67	3

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 District has determined that the above requirements represent BACT for NOx and VOCs and LAER, for NOx only, during startups and shutdowns of the combustion turbines.

<u>PM10 and SOx—Combustion Turbines</u>

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 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.

<u>PM10 - WSAC</u>

PM10 emission from the WSAC results from the water droplets coming from the cooling tower discharge and is controlled with the drift eliminator to limit the drift rate. The District consulted the EPA BACT/LAER Clearinghouse, other air district decisions and BACT Guidelines, and ARB for recent BACT/LAER determinations for the most current cooling tower, which have similar emission characteristics to WSACs, drift rates.

● The CPV Sentinel LLC project is permitted by the South Coast Air Quality Management District [CEC Final Approval issued on December 1, 2010 (CEC Docket No. 2007-AFC-3C)]. This project consists of eight GE LMS 100 CTGs similar to the ones proposed for the PPEC. This project cooling tower is limited to drift rate of 0.0005%. This project is still under construction.

● The Osceola Steel Co. was permitted by the Georgia Department of Natural Resources in December 2010 for a steel mill with three cooling towers. The cooling towers are limited to drift rate of 0.0005%. This plant has not been constructed yet.

● The Panda Sherman Power Station was permitted by the Texas Commission on Environmental Quality in February 2010 for a 600MW combined-cycle power plant. The cooling tower for this plant is limited to 0.0005% drift rate. This plant has not been constructed yet.

● The Orange Grove Energy Center is permitted by the San Diego Air Pollution Control District [CEC Final Approval issued on April 8, 2009 (CEC Docket No. 08-AFC-4)] and has been in operation since 2010. The cooling tower for this plant is limited to 0.001% drift rate.

● The El Cajon Energy Project consisting of one 49 MW CTG was permitted by the San Diego Air Pollution Control District in 2010, with a limit of 0.001% for the cooling tower drift rate.

Since the projects permitted with the lower drift rate of 0.0005% have not been in operation, this drift rate is not considered achievable in practice and is not considered BACT. Based on this information, the District has determined that a drift rate of 0.001% is BACT for PPEC cooling tower.

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 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 PPEC, 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 standards. 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 national or state ambient air quality standard. The analysis can be reviewed in more detailed the Appendix A of this determination. The FDOC 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 California Ambient Air Quality Standard.

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

This subsection requires that a PSD evaluation be performed for any new PSD stationary source (a 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 limits on NOx, CO, VOC emissions on the FDOC will keep the project from triggering any PSD requirements under Rule 20.3(a)(3). Since the annual limit suffices to avoid triggering the PSD threshold and NOx, CO and VOC emissions are monitored with CEMS, no limits on hours of normal operations or startup and shutdown are necessary.

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 that the District 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 PPEC will be published in the San Diego Daily Transcript and mailed to EPA and ARB air districts for a 30-day comment period in accordance with Rule 20.3(d)(4).

Rule 20.3(d)(4)(i) requires that the District consider all comments received. The District has considered all comments received before taking final action.

Rule 20.3(d)(5)-Emission Offsets

This provision requires that emission offsets be provided for projects that result in an 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 PPEC, VOC annual emissions are limited to below the major stationary source thresholds by the FDOC permit conditions. Therefore, offsets are only required for NOx emissions. The emission increase of NOx is 70.41 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 84.49 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)]. 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 has agreed to surrender Class A ERCs sufficient to provide all the required offsets for the project prior to the initial operation of the first turbine.

The Applicant currently owns ERCs representing 54.9 tons per year of NOx emission offsets and ERCs representing 70.3 tons of VOC emission offsets. Under District Rule 20.1

(d)(v)(6), the VOC ERCs are discounted by a ratio of 2 to 1 when used to provide NOx emission offsets. The VOC ERCs owned by the applicant thus represent 35.15 tons of NOx emission offsets. Therefore, the Applicant either owns the equivalent of 90.05 tons of NOx emission offsets, which is sufficient to provide the 84.5 tons of NOx emission offsets required. The ERCs owned by the Applicant are listed in Appendix D.

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 the applicant in the state are in compliance with all applicable emissions limitations and standards under the federal Clean Air Act. The applicant, Pio Pico Energy Center, LLC, does not own or operate any other major stationary sources in California. A fund managed by Energy Investors Funds Management, LLC (EIF) indirectly owns PPEC. Other funds managed by EIF also indirectly own, control, and operate two major stationary sources in the state, the Burney Forest Power and the Panoche Energy Center. The required compliance certification for all major sources in the state has been submitted to the District.

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

The Applicant has provided an analysis of various alternatives to the project as part of the application for a CEC license (CEC Docket No. 11-AFC-01). This analysis included a no project alternative, alternative sites, and alternative technologies. The CEC further analyzed the alternatives provided by the Applicant in their Preliminary Staff Assessment (CEC-700-2012-001-PSA, February, 2012). Since all of San Diego County is currently classified as nonattainment 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 (FDOC) is equivalent to a District Authority to Construct. This FDOC will be submitted to the CEC.

District Prohibitory Rules

Rule 50 – Visible Emissions

This rule limits air contaminants emissions into the atmosphere of a 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 40,035 lbs /hr, and an estimated maximum particulate matter emission rate of 5.5 lbs/hr, combustion particulate at maximum load are estimated to be:

Grain loading = [(5.5 lbs/hr)(7,000 gr/lb)] / [(198.025 scf/lb fuel)(40,035 lbs fuel/hr)] = 0.005 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. 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. Equipment is exempt from the standard during 120-minute startup and shutdown periods.

The combustion turbines for this project will be equipped with water injection for the combustors and SCR controls for NOx. Proposed permit conditions limit NOx emissions to 2.5 ppmvd during normal operations, which is far below the 42 ppmvd rule standard. Maximum durations of startups and shutdowns (30 minutes for startup and 11 minutes for shutdown) are shorter than Rule 69.3 requirements. However, commissioning is still subject to the rule standards. The FDOC contains 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 15 x (E/25) ppmvd when operating uncontrolled and 9 x (E/25) ppmvd 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 based on the higher heating value of the fuel. 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. Simple-cycle turbines are exempt from the standards during 120-minute startup and shutdown periods.

The thermal efficiency for each turbine is 38.7%. Therefore the maximum allowable uncontrolled NOx concentration is 23.2 ppmvd based on a 1-hour averaging period at 15% oxygen and the maximum allowable controlled NOx concentration is 13.9 ppmvd. The uncontrolled concentration limit would only be applicable prior to installation of the SCR system.

The combustion turbines for this project will be equipped with water injection for the combustors and SCR controls for NOx. The FDOC permit conditions limit NOx emissions to 2.5 ppmvd during normal operations, which is far below the 13.9 ppmvd rule standard. Maximum durations of startups and shutdowns (30 minutes for startup and 11 minutes for shutdown) are shorter than Rule 69.3.1 requirements. However, commissioning is still subject to the rule standards. The FDOC 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.

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 potential to emit 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 at a receptor where a person could be reasonably anticipated to be exposed. The cancer risk is based on a 70-year exposure for a residence and a shorter exposure time for occupational workers. Additional requirements apply if the cancer risk is expected to exceed ten in a million.

An HRA, which was reviewed by the District, was performed using EPA AP-42 emission factors and California Air Toxics Emission Factors (CATEF) for toxic air contaminant emissions from the project for normal operations. The emissions from the operation of the three combustion turbines were considered. The HRA performed shows that the incremental cancer risk is 0.094 in a million for exposed residents and 0.014 for exposed workers for 500 startups per year. The acute and chronic incremental health impacts measured by the Health Hazard Index (HHI) are also all less than 1.0 at the point of maximum impact (0.011, 0.043, and 0.11 for the chronic, 8-hour, and acute HHIs, respectively) and, therefore, meet Rule 1200 requirements. Although TBACT is not required since the maximum cancer risk is less than one in a million, the oxidation catalyst installed as BACT for CO and VOC emissions also significantly reduces toxic air contaminant emissions and would be considered TBACT for this project—if TBACT had been required. It should be noted that, although the health risk assessment is based on 4337.5 hours of operation for each turbine (4000 hours of normal operation and 500 startups and shutdowns) the annual incremental residential cancer risk would not exceed 0.2 in a million for 8760 hours of operation for each turbine nor would the chronic HHI exceed 0.025. The health risk assessment of this project is further discussed in Appendix B of this document.

Regulation XIV – Title V Operating Permits

The Applicant will submit an application for Title V Operating Permit for this 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 PPEC is not within 1000 feet of any school boundary.

NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)

The PPEC is not a major source of hazardous air pollutants (HAPs) based on the potential to emit over the 10 ton per year major source threshold for a single HAP or the 25 ton per year threshold for all HAPs combined. Estimated total emissions of all toxic air contaminants, calculated using EPA (AP-42) emission factors were about 5.41 tons per year. Therefore, equipment at the PPEC is not subject to NESHAPS applicable to major stationary sources of HAPs.

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.

Sections 60.4320 and 60.4350(b)(1) require new combustion turbines firing natural gas with a rated heat input greater than 850 MMBtu/hour and using CEMS to comply with a NOx standard of 15 ppmvd at 15% O_2 averaged over each four operating hours, or alternatively, a standard of 0.42 pounds per megawatt hour (lb/MW-h) during normal operations.

With SCR as postcombustion emission control, NOx emissions from this combustion turbine are controlled to 2.5 ppmvd at 15% O_2 during normal operation. Assuming NOx emission concentration during startup is 23.1 ppmvd at 15% O_2, NOx emission concentration during shut down is 16.8 ppmvd at 15% $O_{2,}$ the NOx emission concentration averaged over a 4-hour period that has four startups (2 hours of startup), three shutdowns (0.6 hours of shutdown) and 1.45 hours of normal operation is:

> NOx concentration = [23.1 ppm x (2 startups hours)] x [16.8 ppm x (0.6 shutdowns hours)] + (2.5 ppm x 1.45 normal operation hours)] / (4 hours) = 14.8 ppm

Therefore, the turbine is expected to comply with the NOx emission standard of this subpart. Compliance is required through the FDOC 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 = (1.9 lbs/hr) x (1 hour/ 903 MMBtu) = 0.002 lbs/MMBtu

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

Section 60.4335(b) requires turbines 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/MW-h. 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.

Section 60.4345 requires the CEMS to be installed and certified according to Performance Specification 2 in 40 CFR Part 60 Appendix B, or according to Appendix A of 40 CFR Part 75, and each fuel meter and watt meter 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 FDOC 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 FDOC 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 FDOC conditions include a condition to satisfy these requirements. Annual source tests are not required pursuant to Subpart KKKK for combustion turbine equipment with a CEMS. Because this combustion turbine is subject to a NOx limit that is six 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 District Rule 19.2

requirements and CEMS protocol approved by the District and excess emissions and monitoring reports are required by the FDOC 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 FDOC permit contains conditions satisfying these requirements of Subpart KKKK.

ACID RAIN

40 CFR 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).

40 CFR 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 is included in the FDOC permit conditions. The applicant submitted an acid rain application to EPA on September 14, 2011.

40 CFR 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.

<u>40CFR Part 75 – Continuous Emission Monitoring</u>

This part established requirements for the monitoring, recordkeeping, and reporting of SO2, NOx, and CO_2 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 FDOC permit conditions.

VI. ADDITIONAL ISSUES

PARTICULATE EMISSIONS FROM EVAPORATIVE COOLING

The proposed GE LMS100 turbines have inlet air filters located upstream of the evaporative coolers. The evaporative cooler is turned on only during normal operation in hot weather. The particulate emission factor of 5.5 lbs/hr provided by the turbine vendor includes anticipated particulate matter from the evaporative cooler since the reclaimed and/or potable water supply used is expected to comply with the vendor's recommended water quality standards. 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 112 operating hours for each turbine. During the 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 FDOC emission limits. However, during the initial startup, certain emissions standards must remain in effect. These include the 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.

SOURCE TEST FREQUENCY

The FDOC permit conditions require that the frequency of annual compliance source testing be in accordance with the applicable RATA frequency requirements of the federal acid rain program provisions at 40 CFR Part 75, Appendix B, Sections 2.3.1 and 2.3.3. The annual source testing is to show compliance with the NOX, CO, VOC, and ammonia emission limits and to verify the accuracy of the continuous emission monitoring system (CEMS). At a minimum, the acid rain programs provisions require that a source test be performed after four calendar quarters in which the unit operates at least 168 hours in each quarter (any hour the turbine combusts fuel is considered an operating hour for purposes of Part 75). It is expected that a source test would be required once per year for this facility based on the Applicant's proposed approximately 4000 operating hours per year for each turbine, or about 1000 hours per quarter on average.

In cases of where low levels of operation (less than 168 operation hours per quarter) do not trigger a source test, the acid rain program provisions require a test be conducted every eight calendar quarters even if there have not been four quarters with 168 hours or more of operating time in the eight-quarter period. Any such test must be conducted within 720 operating hours of the end of the eight-quarter period.

TUNING

The FDOC permit conditions allow manual control of the SCR ammonia injection system during tuning operations. However, all permit emission limitations remain in effect during tuning operations.

COMBINED-CYCLE TURBINES AS BACT

In determining BACT, the District may consider lower-emitting alternatives to a proposed new emission unit or process. The District had determined for a relatively recent project that a combined-cycle turbine as an alternative to a proposed simple-cycle turbine was not BACT for a peaking power plant. As discussed below, the District has reexamined this issue and reached the same conclusion with regard to combined-cycle being BACT (or LAER) for NOx, CO, and VOC emissions.

For a lower-emitting process to be a viable alternative to a proposed project it must be able to meet the project objectives. Peaking turbines have to start rapidly on command (and also stop rapidly) to respond to changes in the need for power being supplied to the grid. Even before the advent of significant renewable energy sources (see below), peaking turbines tended to undergo a large number of startups and shutdowns during year and often had short run times after each startup to fulfill their basic function of providing electrical energy to the grid quickly to level out fluctuations in electrical demand. Aeroderivative simple-cycle turbines, such as the GE LMS100 or GE LM6000, definitely suit the basic startup requirements for peaking power plants since they can ramp up to full power in ten minutes or less and also shutdown in ten minutes or less. The District notes that the ability to deliver 100 MW in 10 minutes or less may be becoming a standard for quick-start electrical generation requirements (You've Got Ten Minutes, Blankinship, S., Power Engineering, August 1, 2008).

As a result of the basic function of peaking turbines, the District experience is that, although proposed peaking power plants often use several thousand hours of projected operations for permitting purposes, they operate far less in practice except in unusual circumstances. As an example of operations of peaking power plants in San Diego, one of the most used simple-cycle peaking turbines in the District operated on 262 days for about 1115 total hours in 2010. There were about 470 startups and shutdowns and the running time averaged about 2.4 hours per startup.

The mandated increase in highly variable and relatively unpredictable supplies of renewable electrical energy has accentuated the need for electrical generating assets that can be rapidly added to and removed from the grid to maintain a stable electrical power supply (see for example, Flexible Capacity Procurement, Market and Infrastructure Policy Issue Paper, California ISO, January 27, 2012 and the references therein). The highly cyclic operation of peaking power plants may only be accentuated in the future as more renewable energy resources are added to the electrical system and their average running time per startup may be reduced.

Combined-cycle turbines, which recover the waste heat in the combustion turbine exhaust with a heat recovery steam generator (HRSG) and utilize the steam so generated to create additional electrical energy with a steam turbine, are more efficient during steady state operations than simple-cycle turbines. However, because of restrictions on the rate of temperature increases in the HRSG and steam turbine, combined-cycle turbines require a longer time to bring the steam turbine generated portion of power on line after a startup, which is a drawback for peaking service. The temperature ramp requirements may also restrict the ability of the combustion turbine to achieve full load in 10 minutes or less. Combined-cycle turbines also require additional time to shutdown since the steam system must be shutdown before the combustion turbine(s) is shutdown.

Large combined-cycle turbines require a significant amount of time to reach full load (full combustion turbine power plus full steam turbine power). A large combined-cycle turbine may take up to three and a half hours to reach full power during a cold start and up to two hours during a hot start. However, small combined-cycle turbines such as those using GE LM6000s in either in a 2 x 1 (two combustion turbines and one steam turbine) or 1 x 1 configurations can start faster. They reportedly can reach full combustion turbine power in about one-half hour or less (about 80% of the total plant power and equivalent to the simple-cycle output) and full steam turbine power in one to one and a half hours from a cold start when equipped with a HRSG and steam system designed for rapid startups. For a hot start, full plant power can be reached in less than hour (i.e., the full efficiency benefits of the combined-cycle operation are realized in less than an hour). As a "quick start" objective for the project is somewhat of a qualitative nature, it is not clear if the startup times for a small combined-cycle peaking plant are sufficient to meet this objective. It does appear unlikely that a large combined-cycle plant could meet a quick-start objective.

More importantly, excess emissions beyond normal operations are expected to be incurred during the extended startups and shutdowns for all combined-cycle turbines. In addition to the excess emissions from the plant itself, emissions may be incurred from the startup and shutdown of additional quick-starting generation assets, such as reciprocating engines or simple-cycle turbines, that might have to be started to provide needed power while the combined-cycle plant is reaching the needed power level. Also, to achieve the fastest startups, an auxiliary boiler is required to supply steam to the steam system when the combustion turbine and HRSG are not in operation (to keep the steam turbine pressurized and also maintain a vacuum in the steam condenser), adding additional emissions.

During normal operations following a startup, a combined-cycle turbine produces fewer emissions for the same power output because it uses less fuel, which reduces the exhaust flow rate. For NOx, larger emission reductions are possible because a more efficient catalyst can be used in the SCR at the lower exhaust temperatures at the SCR's location in the HRSG.

To analyze the potential net emission impacts of a combined-cycle peaking power plant, the District examined the potential emission impacts of combined-cycle operations for small combined-cycle turbines in comparison to simple-cycle turbines. The District was unable to obtain any information on the GE LMS100 turbine, the turbine proposed for this project, operating in a combined-cycle mode. Certain features of the LMS100, a lower exhaust temperature than other aeroderivative turbines, may potentially allow this combustion turbine to reach full load more rapidly in the combine-cycle mode, thereby reducing excess startup emissions. However, offsetting this benefit, the lower exhaust temperature results in a less efficient steam system for electrical power generation, which reduces the efficiency when operating in combined-cycle mode.

In the absence of any information for the LMS100, the District examined potential emissions for power plants using the LM6000 PC SPRINT turbines in combined-cycle and simple-cycle operations as the most representative option for which relevant information was available. This combustion turbine only produces about 50 MW in simple-cycle operation compared to the 100 MW produced by the LMS100. However, it is often operated in a 2 X 1 combined cycle peaking power plant, which produces about 100 MW from the combustion turbines.

One such proposed combined-cycle peaking power plant, is the Henrietta Combined-Cycle Power Plant [CEC Final Approval issued on March 24, 2010 (CEC Docket No. 01-AFC-18C)], a modification to the Henrietta Energy Peaker Project. The proposed modified plant consists of two LM6000 PC SPRINT turbines (generating approximately 100 MW combined) and one steam turbine (generating about 25 MW). The plant is permitted to operate in either simple-cycle or combined-cycle mode. When operating in combined-cycle mode both turbines would produce steam with a once through steam generator (OTSG), a type of HRSG that can run dry and potentially allow the combustion turbines to reach full load before starting the steam system.

Operation	Simple-Cycle	Combined-Cycle
Maximum Power, Mw	100	125
Permitted NOx Exhaust Concentration, ppmvd @ 15% O_2.	2.5	2.0
Maximum NOx Emission Rate During Normal Operations, lb/hr/turbine	4.3	3.4
Startup (Cold), minutes	10	70[a]
Shutdown, minutes	10	30[a]

[a]This includes the 10 minutes of simple-cycle startup preceding the steam system startup.

The above additional 60 minutes for the steam system to reach full load is assumed to be for a cold startup, the worst case. The additional time to reach full load for the steam system might be reduced to about 50 minutes for a hot start (six hour shutdown or less).

The excess startup and shutdown NOx emissions for combined-cycle startups and shutdowns over the simple-cycle operations used in the permitting of the Henrietta project are shown below.

Operation	Simple-Cycle NOx Emissions, lb/event/turbine	Additional Combined-Cycle NOx Emissions, lb/event/turbine
Startup (Cold)	7.7	6.1
Shutdown	7.7	2.1

For long enough run times, the more efficient combined-cycle can make up the NOx emission penalty for a startup and shutdown since it produces more power because the increased efficiency generates less NOx per megawatt-hour. However, in the context of peaking operations, the run times may not be long enough—resulting in increased emissions. Assuming a 100 MW is required, the difference in NOx emissions during normal operations between the simple-cycle and the combined-cycle operations is approximately 4.3 – (0.8)(3.4) = 1.58 lb/hr (the combined-cycle plant need only operate at 80% of full power to produce 100 MW). Thus, based on the above excess startup emissions, it would take about five hours (four hours after the 1-hour startup) until the turbine operating in combined-cycle mode has a net emission benefit. This estimate does not include emissions from additional electrical generating resources necessary until the combine-cycle turbine reaches 100 MW, shutdown emissions, or emissions from any auxiliary boiler. It should be noted that these emissions were used for permitting purposes and are expected to be larger than those encountered during typical operations. Nonetheless, they indicate the potential for increased emissions over simple-cycle operations for certain operating scenarios involving large number of cold startups and short runs times.

Using a separate analysis of simulated cold simple-cycle and combined-cycle startups of an LM6000 PC SPRINT, the District estimates that about three hours of running time are necessary before there is a NOx emission benefit from combined-cycle operations. An estimated four hours of running time were also necessary for a CO and, by implication, a VOC emission benefit from combined-cycle operations. For a hot start, the District expects that combined-cycle benefits would occur after much shorter running times. Nevertheless, since average run times for peaking power plants in San Diego may be two and a half hours or less, a combined-cycle peaking power plant may not be a lower-emitting alternative to a simple-cycle plant. The analysis did not consider the cost-effectiveness of a combined-cycle peaking power plant—another element of BACT.

Because the startup and shutdown characteristics of combined-cycle turbines may not be able to meet the objectives of a peaking power plant—especially considering the changing nature of the electrical supply resources—the District cannot conclude that the a combined-cycle turbine is a feasible alternative to a simple-cycle turbine for peaking power applications. Furthermore, because the operating profile of peaking power plants is relatively unpredictable and because, in some not unlikely operating scenarios, a combined-cycle turbine may result in higher emissions than a simple-cycle turbine, the District cannot conclude based on currently available information that a combined-cycle peaking power plant is lower-emitting than a simple-cycle peaking power plant. Hence, the District does not consider combined-cycle operation BACT. If a combined-cycle peaking power plant is not lower-emitting than simple-cycle plant, it is also not LAER.

The District is unaware of any case where a combined-cycle turbine has been mandated for a peaking power plant. The combined-cycle turbines that are being used in peaking power plant applications have instead been proposed by the applicants, who must balance the additional capital cost and operating cost (excluding fuel) for a combined-cycle turbine with the increase in efficiency and resulting decrease in fuel use. However, the District will continue to monitor and/or investigate this issue and, if combined-cycle technology continues to improve or additional information becomes available, may conclude mandating a combine-cycle turbine is a feasible alternative technology that results in net emission benefits for a peaking power plant.

SIP NEW SOURCE REVIEW RULES

The District's New Source Review (NSR) rules (Rules 20.1, 20.2, 20.3, and 20.4) as approved in the State Implementation Plan (SIP) are not the same as the versions that appear in the District's rulebook. The current versions of the NSR rules in the District's rulebook were approved by the San Diego County Air Pollution Control Board in 1998. The Environmental Protection Agency (EPA) issued a public notice proposing limited approval/disapproval of the District's revised NSR rules in 1999. This limited approval was never finalized. However, in issuing its limited approval, EPA noted that the revised District NSR rules are overall more stringent than the SIP-approved rules (Fed. Register Vol. 64, No. 151 at 42892, August 6, 1999). Thus, the District has consistently applied the local version of the rules codified in its rulebook, and EPA has never challenged this approach.

VII. CONCLUSIONS AND RECOMMENDATIONS

If operated in accordance with the conditions specified in this Final 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.

Signed by Steven Moore / for 5-4-12

Project Engineer Camqui Nguyen Date

Signed by Steven Moore 5-4-12

Senior Engineer Approval Date

APPENDIX A

APPROVAL OF AIR QUALITY IMPACT ANALYSIS

AIR QUALITY IMPACT ANALYSIS

FINAL REVIEW REPORT

PIO PICO ENERGY CENTER PROJECT
APPLICATION 2010-APP-001251

DECEMBER 13, 2011

REVISED
JANUARY 10, 2012
AND
April 12, 2012

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 Pio Pico Energy Center Project (PPEC) by Sierra Research of Sacramento, CA. This report focuses on Section 5.2 of the AFC and the AQIA analysis results provided in the original (March, 2011) and subsequent modeling analysis (October, 2011) performed.

2.0 PROJECT DESCRIPTION

Pio Pico Energy Center, LLC (PPEC LLC) is proposing a simple-cycle power generation project that consists of three General Electric (GE) LMS100 natural gas-fired combustion turbine generators (CTGs). The total net generating capacity would be 300 megawatts (MW), with each CTG capable of generating 100MW. The proposed plant will be owned and operated by PPEC LLC. The electricity generated by this project would be in support of a contract with SDG&E. NOx emissions are controlled with a selective catalytic reduction system and CO emissions are controlled with an oxidation catalyst.

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 three temperature scenarios: extreme hot temperature (110 F), annual average temperature (63 F) and extreme low temperature (30 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% and 50% load. The stack parameters and maximum emission rates for the Screening Modeling are presented in Table 3-1, Start-Up modeling inputs in Table 3-2 and Commissioning modeling inputs in Table 3-3. The maximum predicted screening model impacts are shown in Table 3-4.

After screening modeling, refined modeling was performed using EPA’s AERMOD (Version 11103) 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. 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. The receptor grid was sufficiently dense to identify maximum impacts. AERMAP (Version 11103) was used to determine receptor elevations and controlling hill heights.

The Plume Volume Molar Ratio (PVMRM) method was used in determining predicted NO_2 impacts for all facility operations. Background Ozone data from the Chula Vista monitoring station was used for this purpose. Additionally, a data post processing program included in the new version (11103) of AERMOD was used to perform a refined analysis for the Federal 1-Hour NO_2 Standard. This program adds the predicted hour by hour NO_2 impacts to the monitored background NO_2 value (Chula Vista) for that hour for each receptor. For EPA and PSD modeling requirements, the NO_2 background data used was a very conservative composite daily background file for each calendar month. This file was comprised of the highest monitored NO_2 concentration that occurred for each hour of that month. For District NSR requirements, actual hour-by-hour background NO_2 data, with any missing data filled per the District's draft data filling guidance procedure was used. Per the form of the Federal standard, for each modeled year the highest daily combination of predicted plus background concentration at each receptor is first determined. The 98^{th} percentile value (8^{th} high) can then be calculated for each receptor for each of the three years. A three year average 98^{th} percentile value for each receptor is then determined. The highest three year average 98^{th} percentile value at any receptor can then be compared to the Federal 1-Hour standard to determine compliance with this standard.

3.2 METEOROLOGICAL DATA USED FOR DISPERSION MODELING

Meteorological data used for EPA's AERMOD model consisted of the following data for the 2008 through 2010 and 2006 through 2008 time periods. The 2008 through 2010 time period was used to assess all impacts except for 24-hr $PM_{2.5}$ impacts for which, as discussed below, the 2006 through 2008 time period was used. The data was processed by the District using EPA's AERMET meteorological data processor (Version 11059) to produce AERMOD ready files.

- Wind speed, wind direction, standard deviation of the horizontal wind direction and temperature from the District's Otay Mesa monitoring station.
- Twice-daily upper-air soundings from Miramar Marine Corps Air Station, San Diego, CA.
- Cloud height and total opaque cloud amount from Brown Field Airport, Otay Mesa, CA.
- Wind speed, wind direction and temperature data from Brown Field Airport, Otay Mesa, CA for replacement of missing data in the Otay Mesa data set.

Table 3-1
Screening Modeling Inputs
Pio Pico Energy Center

Operating Mode	Ambient Temp deg F	Stack height feet	Stack Diam feet	Stack flow wacfm	Stack Vel ft/sec	Stack Temp deg F	Stack Height meters	Stack Diam Meters	Stack flow m3/sec	Stack Vel m/sec	Stack Temp deg K
Startup/shutdown	30	100	14.5	733,309	74.01	825	30.48	4.4196	346.13	22.56	713.8
Hot Peak	110	100	14.5	877,825	88.60	802	30.48	4.4196	414.34	27.01	700.9
Avg Peak	63	100	14.5	913,717	92.22	785	30.48	4.4196	431.28	28.11	691.2
Cold Peak	30	100	14.5	909,632	91.81	754	30.48	4.4196	429.36	27.98	674.0
Hot Low	122	100	14.5	733,309	74.01	825	30.48	4.4196	346.13	22.56	713.8
Avg Low	63	100	14.5	646,428	65.24	831	30.48	4.4196	305.12	19.89	717.2
Cold Low	30	100	14.5	645,580	65.16	820	30.48	4.4196	304.72	19.86	711.2

Operating Mode	NOx lb/hr	CO lb/hr	SOx lb/hr	PM10 lb/hr	NOx g/sec	CO g/sec	SOx g/sec	PM10 g/sec
Startup/Shutdown	26.63	53.51			3.36	6.74		
Hot Peak	7.72	7.52	1.79	5.50	0.97	0.95	0.23	0.69
Avg Peak	8.18	7.97	1.90	5.50	1.03	1.00	0.24	0.69
Cold Peak	8.07	7.86	1.87	5.50	1.02	0.99	0.24	0.69
Hot Low	5.92	5.77	1.38	5.50	0.75	0.73	0.17	0.69
Avg Low	4.94	4.82	1.15	5.50	0.62	0.61	0.14	0.69
Cold Low	4.92	4.79	1.14	5.50	0.62	0.60	0.14	0.69

Table 3-2
Startup Modeling Inputs
Pio Pico Energy Center

Case	Amb Temp deg F	Stack height feet	Stack Diam feet	Stack flow wacfm	Stack Vel ft/sec	Stack Temp deg F	Stack Height meters	Stack Diam meters	Stack flow m3/sec	Stack Vel m/sec	Stack Temp deg K
Hot Low	122	100	14.5	733,309	74.01	825.1	30.48	4.42	346.13	22.56	713.8

Table 3-3
Commissioning Modeling Inputs
Pio Pico Energy Center

Case	Amb Temp deg F	Stack height feet	Stack Diam feet	Stack flow wacfm	Stack Vel ft/sec	Stack Temp deg F	Stack Height meters	Stack Diam meters	Stack flow m3/sec	Stack Vel m/sec	Stack Temp deg K
Cold Low	30	100	14.5	645,580	65.16	820	30.48	4.42	304.72	19.86	711.2

Table 3-4
Screening Modeling Results
Pio Pico Energy Center (Revised 10/19/2011)

Operating Mode/Year	Conc. (ug/m3) NO2 1-hr	Conc. (ug/m3) CO 1-hr	Conc. (ug/m3) SO2 1-hr	Conc. (ug/m3) SO2 3-hr	Conc. (ug/m3) CO 8-hr	Conc. (ug/m3) PM10 24-hr	Conc. (ug/m3) SO2 24-hr	Conc. (ug/m3) NO2 Annual	Conc. (ug/m3) PM10 Annual	Conc. (ug/m3) SO2 Annual
2008 Met Data										
Startup/shutdown	121.0	243.1			43.1			N/A	N/A	N/A
Hot Peak	29.6	28.8	6.9	2.3	4.8	1.3	0.4	0.2	0.2	0.1
Avg Peak	30.8	30.0	7.2	2.4	5.0	1.3	0.5	0.3	0.2	0.1
Cold Peak	30.8	30.0	7.2	2.4	5.0	1.3	0.5	0.3	0.2	0.1
Hot Low	24.9	24.2	5.8	2.0	4.2	1.5	0.4	0.2	0.2	0.1
Avg Low	22.4	21.8	5.2	1.8	3.9	1.7	0.4	0.2	0.2	0.0
Cold Low	22.3	21.8	5.2	1.8	3.9	1.7	0.4	0.2	0.2	0.0
2009 Met Data										
Startup/shutdown	133.3	267.8			49.5	0.0	0.0	N/A	N/A	N/A
Hot Peak	33.1	32.2	7.7	2.6	6.0	1.7	0.5	0.2	0.2	0.1
Avg Peak	34.4	33.5	8.0	2.7	6.3	1.6	0.6	0.2	0.2	0.1
Cold Peak	34.4	33.6	8.0	2.7	6.3	1.7	0.6	0.2	0.2	0.1
Hot Low	27.6	26.8	6.4	2.2	5.0	1.8	0.4	0.2	0.2	0.0
Avg Low	24.6	24.0	5.7	2.0	4.4	1.9	0.4	0.2	0.2	0.0
Cold Low	24.6	24.0	5.7	2.0	4.4	1.9	0.4	0.2	0.2	0.0
2010 Met Data										
Startup/shutdown	112.1	225.2			64.3	0.0	0.0	N/A	N/A	N/A
Hot Peak	27.7	27.0	6.4	2.2	7.7	1.9	0.6	0.2	0.2	0.0
Avg Peak	28.8	28.1	6.7	2.3	8.0	1.9	0.6	0.2	0.1	0.1
Cold Peak	28.8	28.1	6.7	2.3	8.0	1.9	0.6	0.2	0.2	0.1
Hot Low	23.3	22.7	5.4	1.9	6.5	2.1	0.5	0.2	0.2	0.0
Avg Low	20.7	20.2	4.8	1.7	5.8	2.2	0.5	0.2	0.2	0.0
Cold Low	20.7	20.2	4.8	1.7	5.8	2.2	0.5	0.2	0.2	0.0

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 pollutants and the applicable averaging periods 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 monitoring data for 3 years (2006-2008) for the original modeling and three years (2008-2010) for the October, 2011 modeling addendum. Monitoring data was taken from the District's Otay Mesa 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.

The maximum ground-level impacts at any location from normal operations, startup/shutdowns and the special circumstances of inversion breakup fumigation are presented in Table 4-1.

Table 4-2 provides the summary of project modeled maximum impacts for Commissioning period operating conditions.

Table 4-3 provides the summary of project modeled maximum impacts for Startups and Normal 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 summary for the compliance with the Federal 1-Hour NO_2 and 24-Hour $PM_{2.5}$ standards (2008-2010 meteorological data) (Revised 10/19/11).

Table 4-1
Fumigation Modeling
Pio Pico Energy Center

Emission Rates **Operating Mode**	**NOx lb/hr**	**CO lb/hr**	**SOx lb/hr**	**PM10 lb/hr**		**NOx g/sec**	**CO g/sec**	**SOx g/sec**	**PM10 g/sec**
Startup/Shutdown	26.63	53.51				3.36	6.74		
Hot Peak	7.72	7.52	1.79	5.50		0.97	0.95	0.23	0.69
Avg Peak	8.18	7.97	1.90	5.50		1.03	1.00	0.24	0.69
Cold Peak	8.07	7.86	1.87	5.50		1.02	0.99	0.24	0.69
Hot Low	5.92	5.77	1.38	5.50		0.75	0.73	0.17	0.69
Avg Low	4.94	4.82	1.15	5.50		0.62	0.61	0.14	0.69
Cold Low	4.92	4.79	1.14	5.50		0.62	0.60	0.14	0.69

SCREEN3 Results **Simple Terrain**		Unit Impacts	Distance to Max (m)
Startup/shutdown		0.5907	1197
Hot Peak		0.5867	1198
Avg Peak		0.5703	1206
Cold Peak		0.5582	1214
Hot Low		0.6321	1234
Avg Low		0.6572	1220

Cold Low		0.6359	1232

Table 4-1 (Con't)
Fumigation Modeling
Pio Pico Energy Center

Inversion Breakup Results		**Unit Impacts**	**Distance to Max (m)**
Startup/shutdown		0.8536	21294
Hot Peak		0.7362	23738
Avg Peak		0.7313	23856
Cold Peak		0.7532	23343
Hot Low		0.8247	21840
Avg Low		0.9149	20236
Cold Low		0.9341	19931

Appropriate 1-hr unit impacts to use for longer averaging periods - Inversion Breakup Fumigation

		1-hr unit	3-hr unit	8-hr unit	24-hr unit
Startup/shutdown		0.8536	0.6499	0.4480	0.2429
Hot Peak		0.7362	0.5953	0.4303	0.2384
Avg Peak		0.7313	0.5857	0.4203	0.2321
Cold Peak		0.7532	0.5901	0.4163	0.2282
Hot Low		0.8247	0.6556	0.4677	0.2577
Avg Low		0.9149	0.7074	0.4939	0.2693
Cold Low		0.9341	0.7065	0.4843	0.2618

Inversion Fumigation impacts		**NOx 1-hour**	**CO 1-hour**	**SO2 1- hour**	**SO2 3 -hour**	**CO 8- hour**	**SO2 24- hour**	**PM 24- hour**
Startup/shutdown		2.86	5.75	0.00	0.00	3.02	0.00	0.00
Hot Peak		0.72	0.70	0.17	0.13	0.41	0.05	0.17
Avg Peak		0.75	0.73	0.18	0.14	0.42	0.06	0.16
Cold Peak		0.77	0.75	0.18	0.14	0.41	0.05	0.16
Hot Low		0.62	0.60	0.14	0.11	0.34	0.04	0.18
Avg Low		0.57	0.56	0.13	0.10	0.30	0.04	0.19
Cold Low		0.58	0.56	0.13	0.10	0.29	0.04	0.18

Table 4-2
Modeled Maximum Impacts During Commissioning
(2008-2010 Meteorological Data) (Revised 3/12/12)

Pollutant	**Averaging Period**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Background Concentration ($\mu g/m^3$)**	**Total Concentration[1] ($\mu g/m^3$)**	**NAAQS ($\mu g/m^3$)**	**CAAQS ($\mu g/m^3$)**
NO_2	1-hr	194	135	329	188	339
	Annual	--	30	--	NA	NA
[2]SO_2	1-hr	~~3~~ 8	29	~~32~~ 37	196	655
	3-hr	~~1~~ 3	18	~~19~~ 21	1300	--
	24-hr	~~0~~ 1	10	~~10~~ 11	--	105
	Annual	--	5	--	NA	--
CO	1-hr	375	2863	3238	40,000	23,000
	8-hr	90	2176	2266	10,000	20.000
PM_{10}	24-hr	2	58	60	150	50
	Annual	--	26.7	--	--	NA
$PM_{2.5}$	24-hr	2.2	43.7	45.9	35	--
	Annual	--	12.3	--	NA	NA

[1] The total concentration shown in this table is the sum of the maximum predicted impact and the maximum measured background concentration. Because the maximum impact will not occur at the same time as the maximum background concentration, the actual maximum combined impact will be lower.

[2] Revised to reflect a maximum fuel sulfur content of 0.75 gr/100 scf. Previous modeling used a fuel sulfur content of 0.25gm/100 scf.

Table 4-3
Summary Of Modeling Results
(2008-2010 Meteorological Data) (Revised 10/19/11)

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$) Normal Operation	Modeled Concentration ($\mu g/m^3$) Startup	PSD Significant Impact Level ($\mu g/m^3$)
NO_2	1-hr	34	133	7.5[1]
	Annual	0.3	--	1.0
SO_2	1-hr	8	--	7.8[1]
	3-hr	3	--	25
	24-hr	1	--	5
	Annual	<0.1	--	1.0
CO	1-hr	34	268	2000
	8-hr	8	64	500
PM_{10}	24-hr	2.2	--	5
	Annual	0.24	--	1
$PM_{2.5}$	24-hr	2.2	--	1.2
	Annual	0.24	--	0.3

Notes:
[1] These are interim SILs and have not been formally adopted by EPA.

Table 4-4
Summary of Results (Modeled Maximum Impacts Plus Background)
(2008-2010 Meteorological Data) (Revised 10/19/11)

Pollutant	Averaging Time	Maximum Predicted Impact (operating mode) ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration (Maximum Impact plus Background) ($\mu g/m^3$)	3 year Average of 98th Percentile of Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	CAAQS ($\mu g/m^3$)
NO_2	1-hr	133(startup)	135	268	138	188	339
	Annual	0.3 (normal)	30	30	--	100	57
SO_2	1-hr	8 (normal)	29	37	--	196	655
	3-hr	3 (normal)	18	21	--	1300	--
	24-hr	1 (normal)	10	11	--	--	105
	Annual	<0.1 (normal)	5	5	--	80	--
CO	1-hr	268(shutdown)	2863	3131	--	40,000	23,000
	8-hr	64(shutdown)	2176	2240	--	10,000	20.000
PM_{10}	24-hr	2 (normal)	58	60	--	150	50
	Annual	0.2 (normal)	26.7	26.9	--	--	20
$PM_{2.5}$	24-hr	2.2 (normal)	43.7	--	Not Available[2]	35	--
		2.6 (normal)[3]	45.7[3]	--	25.9[3]	35	--
	Annual	0.24 (normal)	12.3	12.6	--	15.0	12

[1] 40 CFR 51.165 (b)(2).
[2] 2008-2010 $PM_{2.5}$ measurements are only taken every three days. Data substitution to fill missing data was not performed by District. 2006-2008 analysis is shown instead. Note that peak project impact and maximum background concentration are both lower for 2008-2010.
[3] Based on 2006-2008 data.

TABLE 4-5
Summary of Results of Demonstration of Compliance with Federal 1-Hour NO_2 and 24-Hour $PM_{2.5}$ Standards
(2008-2010 Meteorological Data)(Revised 10/19/11)

Standard	Maximum Predicted Impact ($\mu g/m^3$)	Maximum Background Concentration ($\mu g/m^3$)	3 year Average of 98th Percentile of Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
Federal 1-Hour NO_2	133 (startup)	135	138[3]	188
Federal 1-Hour NO_2	133 (startup)	135	121[4]	188
Federal 24-Hour $PM_{2.5}$	2.2 (normal)	43.7	Not Available[1]	35
Federal 24-Hour $PM_{2.5}$	2.6 (normal)[2]	45.7[2]	25.9[2]	35

[1] 2008-2010 $PM_{2.5}$ measurements are only taken every three days. Data substitution to fill missing data was not performed by District. 2006-2008 analysis is shown instead.
[2] Based on 2006-2008 data.
[3] Based on composite daily NO_2 background file(Chula Vista monitoring station).
[4] Based on actual hour by hour filled NO_2 background file(Chula Vista monitoring station).

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 0.24 $\mu g/m^3$ predicted annual impact is well below PSD Significant Impact Levels (SILs) shown in Table 5-1. 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, or attainment of, the Federal Ambient Air Quality Standard. The District considers that this is the case for California Annual PM_{10} Ambient Air Quality Standards as well.

Since the initial modeling estimated maximum 24-Hour PM_{10} impacts of approximately 2.2 $\mu g/m^3$, additional AERMOD modeling could be performed for all days in the 2008-2010 period that the 24-Hour PM_{10} background concentrations exceeded 48 $\mu g/m^3$ to determine whether additional violations of the applicable standard would result from facility operations. Data from both the Chula Vista monitoring station and the new Donovan correctional facility monitoring station were reviewed for this purpose. All days with monitored values greater than 46 µg/m^3 were modeled.

This analysis demonstrates that the sum of the worst case impact and monitored background value for each of these days would not result in an additional violation of the standard. The results are summarized in Table 5-2. It can therefore 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 $PM_{2.5}$ ambient air quality standard is predicted. Monitored background levels exceeded the California $PM_{2.5}$ Annual Standard. Since the background is already in exceedance of the Annual standard no additional violations can be due to facility operations. Additionally, the 0.24 µg/m^3 predicted annual impact is below PSD SILs shown in Table 5-1 for $PM_{2.5}$. 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, projet impacts less than the SILs are deemed to not significantly cause or contribute to violations of, or attainment of, the Federal Ambient Air Quality Standard. The District considers that this is the case for California Annual $PM_{2.5}$ Ambient Air Quality Standards as well.

Table 5-1
Comparison Of Maximum Modeled Impacts During Normal Operation And PSD Significant Impact Levels
(2008-2010 Meteorological Data) (Revised 10/19/11)

Pollutant	Averaging Time	Significant Impact Level, µg/m^3	Maximum Modeled Impact for PPEC, µg/m^3	Exceed Significant Impact Level?
NO_2	1-Hour	7.5[1]	34	Yes
	Annual	1	0.3	No
SO_2	1-Hour	7.8[1]	8	No
	3-hour	25	3	No
	24-Hour	5	1	No
	Annual	1	<0.1	No
CO	1-Hour	2000	34	No
	8-Hour	500	8	No
$PM_{2.5}$	24-Hour	1.2	2.2	Yes
	Annual	0.3	0.24	No
PM_{10}	24-Hour	5	2.2	No
	Annual	1	0.24	No

Notes:
[1] These are interim SILs and have not been formally adopted by EPA

Table 5-2
Demonstration That Project Will Not Cause New Violation Of State 24-Hour PM_{10} Standard (50 µg/m^3)
(2008-2010 Meteorological Data)

Date	Ambient Measurement	Project Impact	Combined Concentration	New Violation?
Chula Vista Monitoring Data (2008-2010)				
10/27/2008	54	2	56	NO
10/28/2009	58	2	60	NO
11/9/2009	53	2	55	NO
1/1/2009	47	2	49	NO
Donovan Monitoring Data (2010)				
1/26/2010	49	0.3	49	NO
8/24/2010	57	0.7	58	NO
9/29/2010	54	0.6	55	NO
10/29/2010	56	0.6	57	NO
12/4/2010	50	0.3	50	NO
12/10/2010	50	0.3	50	NO

Although not part of the District's AQIA evaluation for our FDOC the District notes that because the maximum modeled 1-hour SO_2 impact exceeds the SIL, a further step is necessary to demonstrate that the project's impact is insignificant for PSD purposes. The same EPA guidance that provides the 7.8 µg/m^3 (3 ppb) value[1] also indicates that the SIL is to be compared to either the highest of the 5-year averages of the maximum modeled 1-hour SO_2 concentrations at each receptor, or the highest of the multi-year averages when fewer years are modeled.

The highest modeled 1-hour SO_2 values for each of the three years 2008-2010 are shown in Table 5-3 below. The average of these three values is 7.3 µg/m^3, which is below the SIL of 7.8 µg/m^3 (3 ppb)[1].

Table 5-3
Comparison Of Maximum Modeled Impacts During Normal Operation And PSD Significant Impact Levels for SO_2
(2008-2010 Meteorological Data) (Revised 3/12/12)

Year	Maximum 1-hour SO_2 Impact, µg/m^3
2008	7.2
2009	8.0
2010	6.7
3-year Average	7.3

Notes:
1 This is an interim SIL and has not been formally adopted by EPA

APPENDIX B

APPROVAL OF HEALTH RISK ASSESSMENT

Rule 1200 Health Risk Assessment Report

Site ID:	00471
Application:	001251
Project Engineer:	Steven Moore
Toxics Risk Analyst:	Michael Kehetian
HRA Tools Used:	AERMOD (09292) / HARP On-Ramp / HARP (1.4d)
Report Date:	August 30, 2011

Health Risk Assessment (HRA) evaluation for the Pio Pico Energy Center Project (PPEC)

A health risk assessment (HRA) was evaluated for the Pio Pico Energy Center Project (PPEC) by Sierra Research on behalf of Apex Power Group, LLC. The project is for a 300 megawatt power plant consisting of three simple cycle General Electric LMS 100 natural gas turbines and a cooling tower to be located in Otay Mesa on the southeast instersection of Alta Road and Calzada de la Fuente Road.

The following review references supporting documentation contained in the application for certification provided to the California Energy Commission (CEC) dated February 9, 2011, along with additional supplemental information requested by the District and received on March 8, 2011. The HRA was reviewed for adherence to the Office of Environmental Health Hazard Assessment (OEHHA), Air Resources Board (ARB), and District Rule 1200 guidelines.

Rule 1200 requires the HRA address the increases in potential to emit (PTE) associated with any new or modified emission units. The emission increases for the PPEC are associated with the following sources:

- Three simple cycle turbines each maximally rated at 890.2 MMBtu/hr and equipped with an oxidation catalyst to control volatile organic compounds (VOC) and carbon monoxide (CO) emissions. The oxidation catalyst is assumed to reduce toxic air contaminant (TAC) emissions by 50% during normal operations. The turbines are also equipped with a selective catalytic reduction (SCR) system to control oxides of nitrogen.

- A cooling tower producing aerosol particulate matter emissions from the evaporation of water drift droplets. Using a partial-dry cooling system, the drift eliminator reduces the drift loss rate to 0.001%.

The operating scenarios evaluated to determine the maximum potential health impacts include acute risk from startups and shutdowns, cancer and chronic risk from normal full load operations, the 8-hour hazard index, and health impacts for the commissioning year.

- Annual Emissions - Each turbine operates for 4,000 hours at full load plus 500 startups and 500 shutdowns (4,337.5 hours).

- Hourly Emissions – Each turbine has one startup for 30 minutes with the remainder of the hour at full load. A shutdown for each turbine is for 10.5 minutes with the remainder of the hour at full load.

Worst-Case Potential Health Impacts

Category	Health Impact	Rule 1200 Significance Level
Maximum Incremental Cancer Risk—Resident (per million)	0.094	1.0 or 10 (with TBACT)
Maximum Incremental Cancer Risk—Worker (per million)	0.014	1.0 or 10 (with TBACT)
Total Chronic Noncancer Health Hazard Index	0.011	1.0
Total Acute Noncancer Health Hazard Index	0.11	1.0
Total 8-Hour Noncancer Health Hazard Index	0.42	1.0
Sub-Chronic Lead Exposure Risk (ug/m^3)	5.5E-07	0.12 (ARB Standard)

The reported cancer, chronic, 8-hour, and acute worst-case potential health impacts are at the point of maximum impact (PMI) which is the maximum impact point beyond the facility boundary. The presented worker cancer risk is a conservative ratio of residential exposure assumed to be at the PMI (8/24 hours per day, 245/365 days per year, and 40/70 years).

To determine the worst-case health impacts, modeling consisted of three years (2006, 2007, and 2008) of Otay Mesa meteorological data. For all health impacts, the 2006 meteorological data produced the worst-case results by a small margin.

Cancer risk at the PMI is primarily due to formaldehyde (~49%) and noninhalation exposure to benzo[a]pyrene (~21%) along with dibenz[a,h]anthracene (~13%). The location of the PMI is modeled grid receptor 10443, UTM NAD 83 Zone 11 coordinates 509796 E and 3603904 N.

The chronic health hazard index (HHI) to the respiratory system is mainly due to formaldehyde (~48%) and ammonia (~33%).

Acute risk to the eye endpoint is due to formaldehyde (~79%) and acrolein (~12%). The acute PMI HHI is located at grid receptor 8377, 508696 E and 3604889 N.

On June 18, 2008, the Scientific Review Panel approved OEHHA's Air Toxics Hot Spots Program Technical Support Document (TSD) for the Derivation of Noncancer Reference Exposure Levels (REL) as mandated by the Children's Environmental Health Protection Act of 1999. In addition to revising the chronic and acute health data for several chemicals, a newly added 8-hour hazard index was created. For this project and referencing the Consolidated Table of OEHHA and ARB Approved Risk Assessment Health Values updated on February 14, 2011, 8-hour RELs exist for acetaldehyde, acrolein, and formaldehyde. Since existing OEHHA draft guidance indicates the 8-hour RELs are not target organ specific, the worst-case 8-hour hazard index listed above is the combined total for acetaldehyde, acrolein, and formaldehyde.

The maximum 1-hour lead concentration is estimated to be 5.5E-07 ug/m^3 which is much less than the 30-day High Exposure Scenario approval level of 0.12 ug/m^3 in the ARB Risk Management Guidelines for Lead, 2001. Although the hourly emissions rate equal to 3.6E-09 g/s is ten times less than the 30-day, 2.1E-08 g/s, the results are using the 1-hour averaging period dispersion factor which is significantly higher than what the guidelines require, a 30-day average, so the results are overly conservative.

Emission Factors

Emission factors reference the U.S. EPA AP-42 (Table 3.1-3) and California Air Toxic Emission Factor (CATEF) database for toxic compounds. The turbines are proposed to be equipped with an oxidation catalyst reducing the emission factors by 50% during normal operations. The emission factor for ammonia was calculated based on the proposed permit limit.

Toxic Air Contaminant	Emission Factor Uncontrolled (lb/MMscf)	Source	Emission Factor Controlled (lb/MMBtu)
ACETALDEHYDE	4.08E-02	AP-42	2.00E-05
ACROLEIN	6.53E-03	AP-42	3.21E-06
AMMONIA	7.0	SDAPCD	6.87E-03
BENZENE	1.22E-02	AP-42	5.99E-06
BUTADIENE, 1,3-	4.39E-04	AP-42	2.15E-07
ETHYL BENZENE	3.26E-02	AP-42	1.60E-05
FORMALDEHYDE	9.17E-01	CATEF	4.50E-04
HEXANE-N	2.59E-01	CATEF	1.27E-04
NAPHTHALENE	1.33E-03	AP-42	6.53E-07
PAHs			
ACENAPHTHENE	1.90E-05	CATEF	9.32E-09
ACENAPTHYENE	1.47E-05	CATEF	7.21E-09
ANTHRACENE	3.38E-05	CATEF	1.66E-08
BENZO[a]ANTHRACENE	2.25E-05	CATEF	1.11E-08
BENZO[a]PYRENE	1.39E-05	CATEF	6.82E-09
BENZO[e]PYRENE	5.44E-07	CATEF	2.67E-10
BENZO[b]FLUORANTHENE	1.13E-05	CATEF	5.54E-09
BENZO[k]FLUORANTHENE	1.10E-05	CATEF	5.40E-09
BENZO[g,h,i]PERYLENE	1.37E-05	CATEF	6.72E-09
CHRYSENE	2.52E-05	CATEF	1.24E-08
DIBENZ[a,h]ANTHRACENE	2.36E-05	CATEF	1.15E-08
FLUORANTHENE	4.32E-05	CATEF	2.12E-08
FLUORENE	5.80E-05	CATEF	2.85E-08
INDENO(1,2,3-cd)PYRENE	2.36E-05	CATEF	1.15E-08
PHENANTHRENE	3.13E-04	CATEF	1.54E-07
PYRENE	2.77E-05	CATEF	1.36E-08
PROPYLENE	7.71E-01	CATEF	3.78E-04
PROPYLENE OXIDE	2.96E-02	AP-42	1.45E-05
TOLUENE	1.33E-01	AP-42	6.53E-05
XYLENES	6.53E-02	AP-42	3.20E-05

Emissions – Normal Operations (Each Turbine, 4337.5 hours)

Toxic Air Contaminant	Emission Factor Controlled (lb/MMBtu)	Emissions (lb/hr)	Emissions (lb/yr)
ACETALDEHYDE	2.00E-05	1.78E-02	7.72E+01
ACROLEIN	3.21E-06	2.86E-03	1.24E+01
AMMONIA	6.87E-03	6.12E+00	2.66E+04
BENZENE	5.99E-06	5.33E-03	2.32E+01
BUTADIENE, 1,3-	2.15E-07	1.92E-04	8.32E-01
ETHYL BENZENE	1.60E-05	1.42E-02	6.18E+01
FORMALDEHYDE	4.50E-04	4.01E-01	1.74E+03
HEXANE-N	1.27E-04	1.13E-01	4.90E+02
NAPHTHALENE	6.53E-07	5.81E-04	2.52E+00
PAHs			
ACENAPHTHENE	9.32E-09	8.30E-06	3.60E-02
ACENAPTHYENE	7.21E-09	6.42E-06	2.78E-02
ANTHRACENE	1.66E-08	1.48E-05	6.40E-02
BENZO[a]ANTHRACENE	1.11E-08	9.87E-06	4.28E-02
BENZO[a]PYRENE	6.82E-09	6.07E-06	2.64E-02
BENZO[e]PYRENE	2.67E-10	2.38E-07	1.03E-03
BENZO[b]FLUORANTHENE	5.54E-09	4.94E-06	2.14E-02
BENZO[k]FLUORANTHENE	5.40E-09	4.81E-06	2.08E-02
BENZO[g,h,i]PERYLENE	6.72E-09	5.98E-06	2.60E-02
CHRYSENE	1.24E-08	1.10E-05	4.78E-02
DIBENZ[a,h]ANTHRACENE	1.15E-08	1.03E-05	4.46E-02
FLUORANTHENE	2.12E-08	1.89E-05	8.18E-02
FLUORENE	2.85E-08	2.53E-05	1.10E-01
INDENO(1,2,3-cd)PYRENE	1.15E-08	1.03E-05	4.46E-02
PHENANTHRENE	1.54E-07	1.37E-04	5.94E-01
PYRENE	1.36E-08	1.21E-05	5.26E-02
PROPYLENE	3.78E-04	3.37E-01	1.46E+03
PROPYLENE OXIDE	1.45E-05	1.29E-02	5.60E+01
TOLUENE	6.53E-05	5.81E-02	2.52E+02
XYLENES	3.20E-05	2.85E-02	1.24E+02

Hourly TAC emissions during startup and shutdown are scaled up as a ratio of volatile emissions from normal operations as determined by the applicant to account for overall combustion conditions and limited/non-operational control from the oxidation catalyst. Toxic emissions during an hour including a shutdown are the highest as are the worst-case acute health impacts.

Emissions – Scaled VOCs for Startup and Shutdown

Operating Mode	VOC Emissions (lb/hr)	Ratio of Normal Operations
Normal Operations	2.28	--
Startup	5.81	2.55
Shutdown	6.53	2.86

Emissions – Shutdown (Worst-Case)

Toxic Air Contaminant	Emission Factor Controlled (lb/MMBtu)	Emissions (lb/hr)
ACETALDEHYDE	2.00E-05	5.10E-02
ACROLEIN	3.21E-06	8.18E-03
AMMONIA	6.87E-03	6.12E+00
BENZENE	5.99E-06	1.53E-02
BUTADIENE, 1,3-	2.15E-07	5.49E-04
ETHYL BENZENE	1.60E-05	4.08E-02
FORMALDEHYDE	4.50E-04	1.15E+00
HEXANE-N	1.27E-04	3.24E-01
NAPHTHALENE	6.53E-07	1.66E-03
PAHs		
ACENAPHTHENE	9.32E-09	2.38E-05
ACENAPTHYENE	7.21E-09	1.84E-05
ANTHRACENE	1.66E-08	4.23E-05
BENZO[a]ANTHRACENE	1.11E-08	2.83E-05
BENZO[a]PYRENE	6.82E-09	1.74E-05
BENZO[e]PYRENE	2.67E-10	6.80E-07
BENZO[b]FLUORANTHENE	5.54E-09	1.41E-05
BENZO[k]FLUORANTHENE	5.40E-09	1.38E-05
BENZO[g,h,i]PERYLENE	6.72E-09	1.71E-05
CHRYSENE	1.24E-08	3.15E-05
DIBENZ[a,h]ANTHRACENE	1.15E-08	2.94E-05
FLUORANTHENE	2.12E-08	5.40E-05
FLUORENE	2.85E-08	7.25E-05
INDENO(1,2,3-cd)PYRENE	1.15E-08	2.94E-05
PHENANTHRENE	1.54E-07	3.93E-04
PYRENE	1.36E-08	3.48E-05
PROPYLENE	3.78E-04	9.64E-01
PROPYLENE OXIDE	1.45E-05	3.70E-02
TOLUENE	6.53E-05	1.66E-01
XYLENES	3.20E-05	8.17E-02

Commissioning TAC emissions rates use those from normal operations assuming no control from the oxidation catalyst. The reported cancer, chronic, and acute commissioning worst-case potential health impacts are at the PMI. Cancer risk conservatively assumes 70 year exposure to simultaneous one year commissioning of all three turbines which is a total of 336 hours (112 hours per year for each turbine).

Commissioning Health Impacts

Category	Health Impact
Maximum Incremental Cancer Risk—Resident (per million)	0.0007
Total Chronic Noncancer Health Hazard Index	0.003
Total Acute Noncancer Health Hazard Index	0.027

The partial dry cooling tower operates annually for 4,337.5 hours, a water circulation rate of 14,000 gallons per minute (GPM), and 4.67 cycles of concentration. The maximum total dissolved solids (TSD) is 5,600 ppmw. The concentration for each TAC in the make-up water is determined from the highest water samples collected from the Otay Water District's Ralph W. Chapman Water Recycling Facility effluent in 2007, 2008, and 2009.

Based on a drift rate of 0.001% at the circulators cooling water, which results in maximum particulate emissions of 15.8 pounds per day and 1.43 tons per year, maximum toxic emissions from the cooling tower are:

Emissions - Cooling Towers (Each of the 12 Cells)

Toxic Air Contaminant	Concentration (ug/liter)	Emissions (lb/hr)	Emissions (lb/yr)
ARSENIC	1.80E+00	4.91E-09	2.12E-05
CARBON TETRACHLORIDE	2.10E+00	5.73E-09	2.48E-05
CHLORINE	2.30E+05	6.28E-04	2.72E+00
CHROMIUM	2.80E+00	7.64E-09	3.32E-05
COPPER	6.50E+00	1.77E-08	7.70E-05
FLUORIDE	6.60E+02	3.00E-06	1.30E-02
LEAD	8.60E-01	2.35E-09	1.02E-05

Air Dispersion Modeling

The US Environmental Protection Agency (EPA) AERMOD Dispersion Model (Version 09292) was used to predict concentration impacts using an emissions rate input of 1 g/s.

The District's Monitoring & Technical Services (M&TS) Division provided the AERMET preprocessor files used which included the following three years (2006, 2007, and 2008) of meteorological data:

Surface Data – Otay Mesa-Paseo International Monitoring Station.
Upper Air Data – MCAS Miramar Monitoring Station.

For all health impacts, the 2006 meteorological data predicted the worst-case results by a small margin.

The dispersion results, X/Q (ug/m^3)/(g/s), were imported into ARB's Hotspots Analysis Reporting Program (HARP, Version 1.4d) via HARP On-Ramp to calculate actual chemical concentrations and resulting health impacts.

The dispersion modeling included a course 250-meter spacing grid extending out 10 km to assess the extent of maximum impacts. Refined 25-meter resolution receptor grids surrounding the areas of maximum impacts in addition to along the facility fenceline property boundary is sufficiently dense.

Release Parameters – Modeled Operating Modes

Operating Mode	Ambient Temperature (deg F)	Exhaust Temperature (deg F)	Exhaust Velocity (m/s)
Startup/Shutdown	30	820	19.86
Hot Peak	110	802	27.01
Average Peak	63	785	28.11
Cold Peak	30	754	27.98
Hot Low	122	825	22.56
Average Low	63	831	19.89
Cold Low	30	820	19.86

Release Parameters – Normal Operations (Worst-Case, Cold Peak)

Release Parameter	Value
Stack Height (ft)	100
Stack Diameter (ft)	14.5
Temperature deg F	754
Exhaust Velocity (fps)	91.81

Release Parameters – Startup/Shutdown, Commissioning, 8-Hour (Worst-Case, Cold Low)

Release Parameter	Value
Stack Height (ft)	100
Stack Diameter (ft)	14.5
Temperature deg F	820
Exhaust Velocity (fps)	65.16

Release Parameters – Cooling Towers

Release Parameter	Value
Stack Height (ft)	22
Stack Diameter (ft)	13
Temperature deg F	86
Exhaust Velocity (fps)	33.73

Risk Calculations

The HRA was reviewed using ARB's Hotspots Analysis and Reporting Program (HARP), Version 1.4d, referencing the OEHHA Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments, August 2003.

- Inhalation Breathing Rates and Exposure Duration: For calculating residential cancer risk over 70 years with inhalation as one of the two dominant pathways, the ARB Derived (Adjusted) Analysis Method was used which incorporates the minimum 80^{th} percentile breathing rate equal to 302 Liters/Kilogram-day in accordance with the recommended interim risk management policy for inhalation-based residential cancer risk.

  The worker cancer risk is a conservative ratio of residential exposure (8/24 hours per day, 245/365 days per year, and 40/70 years).

  In accordance with the OEHHA Guidance Manual, *Calculating Cancer Risk Using Different Exposure Durations*, Section 8.2.2, *B. Worker*, a ground level concentration (GLC) adjustment factor was not applied to calculate occupational cancer risk since potential emissions are continuous (24 hours a day, 7 days per week).

- Noninhalation Exposure: Cancer and chronic health impacts include the required noninhalation pathways of dermal contact and soil ingestion per the OEHHA Guidance Manual, *Determination of Noninhalation (Oral) Cancer Risk*, Section 8.2.4, and *Noncancer Chronic Health Impacts from the Oral Route*, Section 8.3.2.

  In addition to the exposure pathways of dermal contact and soil ingestion, residential cancer risk conservatively includes the rural home grown produce pathway with a human ingestion fraction equal to 15%.

  The drinking water and fish consumption pathways using the default fraction of 1.0 (fraction of ingested fish and drinking water from contaminated source) were included in the analysis for the Otay Lake Reservoir.

- Deposition Rate: In accordance with the OEHHA Guidance Manual, *Criteria for Exposure Pathway Evaluation*, Section 5.2, noninhalation exposure used the OEHHA deposition rate equal to 0.05 meters per second, which conservatively assumes particulate matter of less than or equal to 10 microns in diameter (PM_{10}).

- The acute hazard index was calculated using the conservative default simple concurrent maximum approach. At each receptor, the maximum hourly dispersion factors for the entire period are summed from all sources assuming these impacts occur simultaneously at the same location. The more refined approach processes the meteorological data hourly variation dispersion impacts from different sources which for a given receptor will not necessarily be at their maximums at the same time.

APPENDIX C

PERMIT CONDITIONS

PIO PICO ENERGY CENTER (PPEC) 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, the applicant shall maintain and operate the equipment and any associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. [Rule 21 and 40 CFR §60.11]

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 Application No. APCD2010-APP-001251. [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. Prior to the initial startup date for any of the three combustion turbines, the applicant shall surrender to the District Class A Emission Reduction Credits (ERCs) in an amount equivalent to 84.5 tons per year of oxides of nitrogen (NOx) to offset the net maximum allowable increase of 70.4 tons per year of NOx emissions for the three combustion turbines described in District Application No. APCD2010-APP-001251. [Rule 20.3(d)(8)]

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

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 acquire, 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 21]

COMBUSTION TURBINE CONDITIONS

Definitions

10. For purposes of determining compliance with the emission limits of this permit, a shutdown period is the 11 minutes period preceding the moment at which fuel flow ceases. [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 30 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. 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 are 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]

14. For each combustion turbine, the commissioning period is the period of time commencing with the initial startup, also known as the first fire, of that turbine and ending after 112 hours of turbine operation, or the date the pemittee notifies the District the commissioning period has ended. For purposes of this condition, the number of hours of turbine operation is defined as the total unit operating minutes during the commissioning period divided by 60. [Rule 20.3(d)(1)]

15. For each combustion turbine, a unit operating day, hour, and minute mean the following:
    a. A unit operating day means any calendar day in which the turbine combusts fuel.
    b. A unit operating hour means any clock hour in which the turbine combusts fuel for any part of the hour or for the entire hour.
    c. A unit operating minute means any clock minute in which the turbine combusts any fuel.

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

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

General Conditions

17. The exhaust stacks for each combustion turbine shall be at least 100 feet in height above site base elevation. [Rules 20.3(d)(2) and 1200]

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

19. Unless otherwise specified in this permit or the District approved CEMS Protocol, 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

20. 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]

21. 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]

22. 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 except as specified in the District approved CEMS Protocol [Rules 69.3, 69.3.1, and 20.3(d)(1)]

23. 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 2.5 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen averaged over a 1-clock-hour period, except during commissioning, startup, and shutdown periods for that turbine.
[Rule 20.3(d)(1)]

24. When a combustion turbine is operating, the emission concentration of carbon monoxide (CO) shall not exceed 4.0 ppmvd corrected to 15 % oxygen, averaged over a 1-clock-hour period, except during commissioning, startup, and shutdown periods for that turbine.
[Rule 20.3(d)(1)]

25. 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, startup, and shutdown periods for that turbine. For purposes of determining compliance based on the CEMS, the District approved VOC/CO surrogate relationship, the CO CEMS data, averaged over a 1-clock-hour period be used. The VOC/CO surrogate relationship shall be verified and/or modified, if necessary, based on source testing. [Rule 20.3(d)(1)]

26. When a combustion turbine is operating, the ammonia concentration (ammonia slip), shall not exceed 5.0 ppmvd corrected to 15 % oxygen, except during commissioning, startup, and shutdown periods for that turbine. [Rule 1200]

27. 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 13.9 ppmvd calculated over each clock-hour period and corrected to 15% oxygen, except during startup and shutdown periods, 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]

28. 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 23.2 parts per million by volume on a dry basis (ppmvd) calculated over each clock-hour period and corrected to 15% oxygen, except during startup and shutdown periods, 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]

29. 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 startup and shutdown periods, 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]

30. For each rolling 4-unit-operating- hour 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 4-unit-operating-hour period. The hourly emission concentration limit and emission rate limit shall be 15 ppmvd corrected to 15% oxygen and 0.43 lb/MWh, respectively at all times during the clock hour. 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 startup and shutdown 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. [40 CFR Part 60 Subpart KKKK]

31. The emissions of particulate matter less than or equal to 10 microns in diameter (PM10) shall not exceed 5.5 pounds per hour for each combustion turbine. [Rule 20.3(d)(2)]

32. 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]

33. 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]

34. Mass emissions from each combustion turbine of oxides of nitrogen (NOx), calculated as NO_2; carbon monoxide (CO); and volatile organic compounds (VOC), calculated as methane, shall not exceed the following limits, except during commissioning, startup, and shutdown periods for that turbine. A 1-clock-hour averaging period for these limits shall apply to CEMS data.

Pollutant	Emission Limit, lb/hour
a. NOx	8.2
b. CO	8.0
c. VOC	2.3

[Rule 20.3(d)(2)]

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

Pollutant	Emission Limit, lb/event
a. NOx	22.5
b. CO	17.9
c. VOC	4.7

[Rule 20.3(d)(1)]

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

Pollutant	Emission Limit, lb/event
a. NOx	6.0
b. CO	47.0
c. VOC	3.0

[Rule 20.3(d)(1)]

37. The oxides of nitrogen (NOx) emissions from each combustion turbine shall not exceed 50 pounds per hour and total aggregate NOx emissions from all combustion turbines combined shall not exceed 150 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 more turbines are operating, including, but not limited to, emissions during commissioning, startup, and shutdown periods. [Rule 20.3(d)(2)]

38. The carbon monoxide (CO) emissions from each combustion turbine shall not exceed 75 pounds per hour and total aggregate CO emissions from all combustion turbines combined shall not exceed 225 pounds per hour measured over each 1-clock-hour period. This emission limit shall apply during all times that one or more turbines are operating, including, but not limited to emissions during commissioning, startup, and shutdown periods. [Rule 20.3(d)(2)(i)]

39. Beginning with the earlier of the initial startup dates for any combustion turbine, aggregate emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide (NO_2); carbon monoxide (CO); volatile organic compounds (VOCs), calculated as methane; particulate matter less than or equal to 10 microns in diameter (PM10); and oxides of sulfur (SOx), calculated as sulfur dioxide (SO_2), from the combustion turbines described in District Application No. APCD2010-APP-001251, except emissions from emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d) (1), shall not exceed the following limits for each rolling 12-calendar-month period:

	Pollutant	Emission Limit, tons per year
a.	NOx	70.4
b.	CO	96.4
c.	VOC	19.4
d.	PM10	35.8
e.	SOx	4.1

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, startup, and shutdown periods. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

40. The cooling tower shall be equipped with a mist eliminator designed to achieve a drift rate of 0.001% or less. 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 mist eliminator. In addition, the maximum total dissolved solids (TDS) concentration of the water used in the cooling tower shall not exceed 5,600 ppm. The TDS concentration shall be verified through quarterly testing of the water by a certified lab using an EPA approved method. [Rule 20.3(d)(1)]

41. 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, calculated as methane; PM10; and SOx, calculated as SO_2, in tons, from each emission unit described in District Application No. APCD2010-APP-001251, except for emissions from 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. The recorded emissions shall be calculated in accordance with an emission calculation protocol approved by the District. A proposed emission calculation protocol to calculate the emissions from each emission unit shall be submitted to the District for approval not later than 90 calendar days before the earlier of the initial startup dates for either of the three combustion turbines. Where applicable, this protocol may rely in whole or in part on the CEMS Protocol or other monitoring protocols required by this permit. [Rules 20.3(d)(3), 20.3(d)(8) and 21]

42. 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, calculated as methane; PM10; and SOx, calculated as $SO_{2,}$ in tons from all the emission units described in District Application No. APCD2010-APP-001251 combined, except for emissions from 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]

Ammonia - SCR

43. 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; the catalyst volume, space velocity and area velocity at full load; and control efficiencies of the SCR and the oxidation catalyst CO at temperatures between 100 ºF and 1000 ºF at space velocities corresponding to 100% load. Such information may be submitted to the District as trade secret and confidential pursuant to District Rules 175 and 176. [Rules 20.3(d)(1) and 14]

44. When a combustion turbine is operating, ammonia shall be injected at all times that the associated selective catalytic reduction (SCR) system outlet temperature is 575 degrees Fahrenheit or greater. [Rules 20.3(d)(1)]

45. Continuous monitors shall be installed on each SCR system prior to their initial operation to monitor or calculate, and record the ammonia solution injection rate in pounds per hour and the SCR outlet temperature in degrees Fahrenheit for each unit operating minute. The monitors shall be installed, calibrated and maintained in accordance with a District approved protocol, which may be part of the CEMS Protocol. This protocol, which shall include the calculation methodology, shall be submitted to the District for written approval at least 90 calendar 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)]

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

47. 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

48. All source test or other tests required by this permit shall be performed by the District or by an independent contractor and witnessed 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, a proposed test protocol shall be submitted to the District for written approval at least 60 calendar days prior to source testing. Additionally, the District shall be notified a minimum of 30 calendar 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]

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

50. 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 calendar 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]

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

    a. Measurements of NOx and CO concentrations and emissions and oxygen (O_2) concentration shall be conducted in accordance with U.S. Environmental Protection Agency (EPA) methods 7E, 10, and 3A, respectively, and District source test Method 100, or alternative methods approved by the District and EPA.

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

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

    d. Measurements of PM10 emissions shall be conducted in accordance with EPA Method 5 and 202 or alternative methods approved by the District and EPA. For purposes of this permit, all the particulate matter measured shall be considered to be PM10.

    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.

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

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

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

52. A renewal source test and a NOx and CO Relative Accuracy Test Audit (RATA) shall be periodically conducted on each combustion turbine to demonstrate compliance with the NOx, CO, VOC and ammonia emission standards of this permit and applicable relative accuracy requirements for the CEMS systems using District approved methods. The renewal source test and the NOx and CO RATAs shall be conducted in accordance with the applicable RATA frequency requirements of 40 CFR75, Appendix B, Sections 2.3.1 and 2.3.3. The renewal source test shall be conducted in accordance with a protocol complying with all the applicable requirements of the source test protocol for the Initial Emissions Source Test. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

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

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

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

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

55. 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]

56. 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, in conjunction with ASTM D3588-98, Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, 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]

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

CONTINUOUS MONITORING

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

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

    a. Hourly average(s) concentration of oxides of nitrogen (NOx) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the NOx limits of this permit;
    b. Hourly average concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), necessary to demonstrate compliance with the CO limits of this permit;
    c. Percent oxygen (O_2) in the exhaust gas for each unit operating minute;
    d. Hourly 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. Daily mass emissions of oxides of nitrogen (NOx), in pounds;
    g. Calendar monthly mass emissions of oxides of nitrogen (NOx), in pounds;

h. Rolling 4-unit-operating-hour average concentration of oxides of nitrogen (NOx) corrected to 15% oxygen, in parts per million (ppmvd);
i. Rolling 4-unit-operating-hour average oxides of nitrogen (NOx) emission rate, in pounds per megawatt-hour (MWh);
j. Calendar quarter, calendar year, and rolling 12-calendar-month period mass emissions of oxides of nitrogen (NOx), in tons;
k. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds;
l. Hourly mass emissions of carbon monoxide (CO), in pounds;
m. Daily mass emission of carbon monoxide (CO), in pounds;
n. Calendar monthly mass emission of carbon monoxide (CO), in pounds;
o. Rolling 12-calendar-month period mass emission of carbon monoxide (CO), in tons;
p. Average concentration of oxides of nitrogen (NOx) and carbon monoxide (CO)uncorrected and corrected to 15% oxygen, in parts per million (ppmvd), during each unit operating minute;
q. Average emission rate in pounds per hour of oxides of nitrogen (NOx) and carbon monoxide (CO) during each unit operating minute.

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

60. 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]

61. No later than the earlier of 90 unit operating days or 180 calendar days after each combustion turbine commences commercial operation, a Relative Accuracy Test Audit (RATA) and other required certification tests shall be performed an completed on the that turbine's NOx CEMS in accordance with 40 CFR Part 75 Appendix A and on the CO CEMS in accordance with 40 CFR Part 60 Appendix B. The RATAs shall demonstrate that the NOx and CO CEMS comply with the applicable relative accuracy requirements. At least 60 calendar days prior to the test date, the 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. For purposes of this condition, commences commercial operation is defined as the first instance when power is sold to the electrical grid. [Rules 69.3, 69.3.1, and 20.3(d)(1) and 40 CFR Part 60 Subpart KKKK, and 40 CFR Part 75]

62. A monitoring plan in conformance with 40 CFR 75.53 shall be submitted to U.S EPA Region 9 and the District at least 45 calendar days prior to the Relative Accuracy Test Audit (RATA), as required in 40 CFR 75.62. [40 CFR Part 75]

63. 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 Part 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]

64. 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 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]

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

66. 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. [H&S §42706]

67. 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 the CEMS Protocol approved by the District. [Rule 19.2]

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

69. 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 VOC/CO surrogate relationship that shall be used to demonstrate compliance with all VOC emission limits. This protocol can be provided as part of the Initial Source Emissions Test Protocol. [Rule 20.3(d)(1)]

70. 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]

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

    a. Date and time;
    b. Natural gas flow rate to the combustion turbine during each unit operating minute, in standard cubic feet per hour;
    c. Total heat input to the combustion turbine based the fuels higher heating value during each unit operating minute, in million British thermal units per hour (MMBtu/hr);
    d. Higher heating value of the fuel on an hourly basis, in million British thermal units per standard cubic foot (MMBtu/scf);
    e. Combustion turbine electrical energy output during each unit operating minute in gross megawatts hours (MWh);

    The values of these operational characteristics shall be recorded each unit operating minute. The monitors shall be installed, calibrated, and maintained in accordance with the 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]

72. At least 90 calendar days prior to initial startup of the each combustion turbine, the applicant shall submit a turbine operation 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]

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

COMMISSIONING

74. 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)]

75. 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 startup and shutdown periods, the emissions of NOx and CO during startup and shutdown periods, and the emissions of NOx and CO during steady state operation. This report shall also detail any turbine or emission control equipment malfunction, upset, repairs, maintenance, modifications, or replacements affecting emissions of air contaminants that occurred during the commissioning period. All of the following continuous monitoring information shall be

reported for each minute and, except for cumulative mass emissions, averaged over each hour of operation:

a. Concentration of oxides of nitrogen (NOx) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);
b. Concentration of carbon monoxide (CO) uncorrected and corrected to 15% oxygen, in parts per million (ppmvd);
c. Percent oxygen (O_2) in the exhaust gas;
d. Mass emissions of oxides of nitrogen (NOx), in pounds;
e. Cumulative mass emissions of oxides of nitrogen (NOx) in each startup and shutdown period, in pounds;
f. Cumulative mass emissions of carbon monoxide (CO) in each startup and shutdown period, in pounds
g. Mass emissions of carbon monoxide (CO), in pounds;
h. Total heat input to the combustion turbine based on the fuel's higher heating value, in million British thermal units per hour (MMBtu/hr);
i. Higher heating value of the fuel on an hourly basis, in million British thermal units per standard cubic foot (MMBtu/scf);
j. Gross electrical power output of the turbine, in megawatts hours (MWh) for each hour; and
k. SCR outlet temperature, in degrees Fahrenheit; and

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)]

76. 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.

In addition, the applicant shall notify the District when: (1) construction is complete by submitting a Construction Completion Notice before operating any unit that is the subject of this permit, (2) each combustion turbine first combusts fuel by submitting a First Fuel Fire Notice within five calendar days of the initial operation of the unit, and (3) each combustion turbine first generates electrical power that is sold by providing written notice within 5 days of this event. [Rules 24 and 21 and 40 CFR Part 75, 40 CFR Part 60 Subpart KKKK, 40 CFR Part §60.7, 40 CFR Part 63 Subpart YYYY, and 40 CFR Part §63.9]

REPORTING

76. The permittee shall file semiannual reports in accordance with 40 CFR §60.4375. [40 CFR Part 60 Subpart KKKK]

77. Each semiannual report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Each such semiannual compliance report shall be postmarked or delivered no later than January 30 or July 30, whichever date is the first date following the end of the semiannual reporting period. [40 CFR Part 60 Subpart KKKK and Rule 21]

78. All semiannual compliance reports shall be submitted to the District Compliance Division [40 CFR §60.7]

APPENDIX D

EMISSION REDUCTION CREDITS

Summary of Emission Reduction Credits (ERCs) Proposed as Offsets

ERC Certificate No.	Original Issue Date	Type	Pollutant	ERC Amount, tons per year	NOx Equivalent Amount, tons per year	Location of Emission Reductions	Description Emission Reduction	Current Owner
00019-01	4/8/2011	A	NOx	29.2	29.2	990 Bay Blvd Chula Vista, CA 91911	Shut down of Units 3 & 4	Dynegy South Bay, LLC
00019-03	4/8/2011	A	VOC	16.2	8.1	990 Bay Blvd Chula Vista, CA 91911	Shut down of Units 3 & 4	Dynegy South Bay, LLC
00039-01	8/11/2011	A	NOx	24.6	24.6	990 Bay Blvd Chula Vista, CA 91911	Shut down of Units 1 & 2 and CT	Dynegy South Bay, LLC
00039-03	8/11/2011	A	VOC	11.2	5.6	990 Bay Blvd Chula Vista, CA 91911	Shut down of Units 1 & 2 and CT	Dynegy South Bay, LLC
090819-01	9/22/2006	A	VOC	18.7	9.35	7757 St. Andrews Ave San Diego, CA 92154	Reduction in emissions from furniture coating operations	IG&E GP, LLC
090819-02	9/22/2006	A	VOC	18.7	9.35	7757 St. Andrews Ave San Diego, CA 92154	Reduction in emissions from furniture coating operations	IG&E GP, LLC
070823-02	11/19/1999	A	VOC	5.3	2.65	850 Lagoon Drive Chula Vista, CA 91910	Shut down of vapor degreasing and cold solvent cleaners	Rohr, Inc.
070823-03	6/17/2003	A	VOC	0.2	0.1	Brown Field San Diego, CA 92126	Shut down of aircraft turbine test cells	Rohr, Inc.
070823-01	6/17/2003	A	NOx	1.1	1.1	Brown Field San Diego, CA 92126	Shut down of aircraft turbine test cells	Rohr, Inc.