GALATI | BLEK LLP

455 Capitol Mall Suite 350
Sacramento CA 95814
Tel • 916.441.6575
Fax • 916.441.6553

DOCKET	
07-AFC-9	
DATE	JUN 26 2009
RECD.	JUN 26 2009

June 26, 2009

California Energy Commission
Docket Unit
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: **FINAL DETERMINATION OF COMPLIANCE (FDOC) FOR CANYON POWER PLANT DOCKET NO. (07-AFC-9)**

Enclosed for filing with the California Energy Commission is the original **FINAL DETERMINATION OF COMPLIANCE (FDOC)**, for the Canyon Power Plant Docket No.(07-AFC-9).

Sincerely,

Marie Mills

Marie Mills

June 24, 2009

Eric Solorio, Project Manager
California Energy Commission
Siting, Transmission and Environmental Protection Division
1516 Ninth Street, MS-15
Sacramento, CA 95814-5512

Subject: Final Determination of Compliance (FDOC) for Canyon Power Plant (CPP) Proposed 200 Megawatt Power Plant Project (Facility ID No. 153992), to be located at 3071 E. Miraloma Avenue, Anaheim, CA 92805 (07-AFC-9)

Dear Mr. Solorio:

This is in reference to the City of Anaheim's Canyon Power Plant (CPP) proposed Power Plant Project Application for Certification (AFC) and Title V Application for a Permit to Construct filed with the California Energy Commission (CEC) and the South Coast Air Quality Management District (AQMD), respectively. As you know, the City of Anaheim has proposed to construct a 200 megawatt (MW) power plant, located at 3071 E. Miraloma Avenue, Anaheim, CA 92805.

On February 25, 2009 the AQMD issued the Preliminary Determination of Compliance (PDOC) to the CPP project. At this time the AQMD has conducted further analysis of the project and considered all comments received during the comment period. Based on our evaluation, AQMD is issuing a Final Determination of Compliance (FDOC) indicating CPP complies with all applicable air quality Rules and Regulations and other AQMD requirements, including emissions offsets requirements of AQMD Rule 1303(b)(2). The purpose of this letter is to transmit our evaluation and the FDOC to CEC and to list the revisions which will be made to the PDOC issued on February 25, 2009, based on our further analysis and comments the AQMD has received from both CEC and the City of Anaheim. The USEPA did not provide comments.

In addition, please note that Attachment A is a summary of the additional minor revisions based on comments received from CEC which will be reflected in the FDOC. Attachment B is a summary of the AQMD's comments on the Preliminary Staff Assessment.

If you have any questions regarding this project, please contact Mr. John Yee at (909) 396-2531 jyee@aqmd.gov. For any questions regarding this letter and the FDOC, please contact Mr. Michael D. Mills, Senior Manager at (909) 396-2578 mmills@aqmd.gov.

Sincerely,

Mohsen Nazemi, P.E.
Deputy Executive Officer
Engineering and Compliance

MN:MDM:vl

cc: Steve Sciortino, City of Anaheim
Scott A. Galati, Galati Blek LLP
Barry Wallerstein, AQMD (w/o enclosures)
Kurt Wiese, AQMD (w/o enclosures)
Barbara Baird, AQMD (w/o enclosures)
Mike Mills, AQMD (w/o enclosures)

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

(FDOC Cover Letter)

ATTACHMENT A

RESPONSE TO COMMENTS FROM THE CEC ON THE PRELIMINARY DETERMINATION OF COMPLIANCE

Comments on PDOC Conditions

1. Facility Conditions – CEC stated that Condition K67.5 in Section D should also be placed in Section H of the Facility Permit similar to Facility Conditions F9.1, F14.1 and F24.1.
   Conditions F9.1, F14.1, and F24.1 are facility conditions, which apply to the entire facility and thus appear automatically in both Sections D and H. Condition K67.5 is a device condition that applies to device E30 only. Device E30 is included in Section D only; thus, condition K67.5 appears in Section D only.

2. Facility Conditions – CEC stated that 40CFR Part 68 referenced in Condition F24.1 does not apply to this project and should be deleted.
   AQMD staff agrees and Condition F24.1 will be deleted from the facility permit.

3. Condition A63.2 – CEC stated that this condition should be removed
   Condition A63.2 was appropriately removed from the PDOC when the scope of the project changed, but inadvertently left on the facility permit. Condition A63.2 will be deleted from the facility permit.

4. Condition E193.1 – CEC stated that this condition should not be incorporated into the Staff Assessment as CEC believes the condition is redundant.
   AQMD believes this condition is not redundant and will continue to require the condition as part of the Title V Facility Permit and the words "air quality" will not be removed from condition E193.1.

5. Condition D29.2 – CEC stated that to be consistent with Condition K40.1, the time frame for source test submittal should be changed to 60 days.
   Condition D29.2 will be revised to require the ammonia source test results to be submitted to the AQMD within 60 days after the test date rather than 45 days.

6. Condition I296.1 and I296.2 RTC Zone Designation – CEC requests the addition of Zone 1 to the permit conditions.
   The comment suggests that the term "Zone 1" be added to these two conditions to clarify that only Zone 1 RTCs are allowed for this facility. On the facility permit, Section A: Facility Information already specifies the zone is "coastal," which is the same as Zone 1. (The zone designation is "inland" for zone 2.) Consequently, there is no need to repeat the requirement in the conditions I296.1 and I296.2. Further, the AQMD's RECLAIM administration team implements the RTC trades and ensures the RTCs are from the correct zone.

7. Conditions A99.1 and A195.1 – CEC stated that the NOx Emission Concentration Limit should be changed to 2.3 ppmv
   The comment states that the NOx emission concentration limit noted in these two conditions should be 2.3 ppm, as stipulated to by the applicant and used by the District in

the NOx emissions and RTC requirement calculations, rather than the 2.5 ppm value shown in these two conditions. These two conditions are based on 2.5 ppm, because that remains the BACT/LAER limit which is the maximum NOx emission concentration, averaged over one hour, which the turbines are required to not exceed.

The 2.3 ppm is used in the NOx emissions and RTC requirement calculations because the NOx emissions concentration averaged over one year is expected to be lower than the 2.5 ppm hourly average limit. The 2.3 ppm is guaranteed by the turbine manufacturer and expected to provide a reasonable estimate of the actual emission increase.

Comments on Engineering Evaluation

8. <u>Rule 1304 Offset Exemption Discussion – CEC stated that AQMD is inconsistent in its implementation of the Superior Court decision concerning use of Rule 1304 exemptions and that Rule 1304 (d)(3) is being applied to the water cooling towers</u>

The first comment is that, although the PDOC states the District cannot issue permits using any Rule 1304 offset exemptions pursuant to a Superior Court decision, the Rule 1304(d)(3) offset exemption appears to have been applied to the cooling tower PM_{10} emissions. The NSR requirements, including offsets requirements, do not apply to the cooling tower because NSR requirements only apply to permitted equipment. The cooling tower is exempt from permitting pursuant to Rule 219(d)(3). Therefore, an offset exemption is not applicable.

On page 61, under *Offset Requirements/NSR Entries*, the PDOC states: "Rule 1303(b)(2) requires a net emission increase in emissions of any nonattainment air contaminant from a new source to be offset unless exempt from offset requirements pursuant to Rule 1304." To provide clarification, the following will be inserted: "'Source' is defined by Rule 1302(ao) to mean "any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air contaminant. This includes any permit unit at any non-RECLAIM facility and any device at a RECLAIM facility."

The second comment is that the basis of the offset calculation for the emergency engine should be changed from the 52 hours of operation used in the PDOC to the permitted 200 hours, the same as was used for the RECLAIM credit calculation. For non-RECLAIM facilities, the District policy is to use 50 hours of operation (or 52 hours to simplify the operating schedule) for the offset calculations, including for NOx, because the NSR rules in Regulation XIII do not specify a basis for the operating schedule. For RECLAIM facilities, Rule 2005(d) specifies the RECLAIM credit calculation shall be based on the potential to emit or on a permit condition limiting the source's emissions. Thus, the RECLAIM credit calculation was based on 200 hours pursuant to the limit set by condition C1.1.

9. <u>Page 46 – Table 10 – CEC statess that the NOx and SO_2 Average Emission Rates are not consistent and do not reflect the levels stipulated by the applicant</u>

The first comment is that the average NOx emission rates presented in PDOC Table 10 were not the final applicant stipulated values. Accordingly, the AQMD followed up with the applicant. The applicant characterized the outdated values as a text error and provided the correct values on 4/21/09. PDOC Table 10 and the NOx emissions and RTC requirement calculations have been revised to reflect the corrected values.

The second comment is that the worse-case short-term SO2 emissions should be based on the SoCalGas sulfur CPUC tariff sheet limit value of 0.75 grains/100 scf, instead of the 1.0 grains/100 scf. As the 1.0 grains/100 scf was used for modeling only, not emissions calculations, the minor overestimate provided conservative modeling results.

10. <u>Page 61 to 71 – CEC stated that the AQMD Offset Requirements/NSR Entries which use rounding procedures propagates errors in determining the offset requirements.</u> This comment suggested that the AQMD determine offsets requirements on a facility-wide basis instead of a permit unit basis. The AQMD has determined offsets requirements for this project on a facility project basis.

ATTACHMENT B

AQMD COMMENTS ON THE PRELIMINARY STAFF ASSESSMENT

1. Pg. 4.1-3: Air Quality Table 1--Laws, Ordinances, Regulations, and Standards (LORS)
For 40 CFR 60 Subpart KKKK, Air Quality Table 1 indicates the NOx emissions limit is 15 ppm at 15% O_2. According to Table 1 to Subpart KKKK of Part 60, the NOx emission standard is 25 ppm at 15% O2 for a new turbine firing natural gas, with a heat input at peak load > 50 MMBtu/h and ≤ 850 MMBtu/h.

2. Pg. 4.1-21: Air Quality Table 13—SCAQMD 30-Day Average Daily Emissions (lbs/day per turbine)
Air Quality Table 13 indicates the SCAQMD 30-Day Average for SO2 is 1.44 lb/day. The 30-day average is 1.2 lb/day, as indicated on pg. 64 of the PDOC. The 1.44 lb/day value is the product of the 1.2 lb/day multiplied by the 1.2 offset ratio.

3. Pg. 4.1-30: Applicant's Proposed Mitigation, Emissions Controls
The PSA states the PDOC conditions provide that the BACT emissions limit for NOx is 2.3 ppmvd at 15% O_2. Table 31—Simple Cycle Gas Turbine MSBACT/LAER Requirements on pg. 81 of the PDOC states the BACT emissions limit for NOx remains 2.5 ppmvd at 15% O_2. Further, conditions A99.1 and A195.1 reflect the 2.5 ppmvd BACT limit.

4. Pg. 4.1-31: Air Quality Table 18—Canyon SCAQMD Offset Requirement Summary (lbs)
Air Quality Table 18 indicates the number of RECLAIM Trading Credits (RTCs) (lbs/year) required for the project is 27,542. Pg. 98 of the PDOC states the number of NOx RTCs required per normal operating year, including the RTCs required for the black start engine, is 30,252. For the FDOC, the number of RTCs will be revised to 29,956 to reflect the correction of the turbine emission rate for NOx from 4.05 lb/hr to 3.98 lb/hr. The correction for the NOx emission rate was received from the CEC and City of Anaheim after the issuance of the PDOC.

5. Pg. 4.1-32: Air Quality Table 20—PM_{10} Offsets Proposed for Canyon
Pg. 4.1-57: Staff Condition AQ-SC7
The credit numbers (certificate numbers) listed in Air Quality Table 20 for the offset source location at 2211 E. Carson St, Long Beach, are for Commonwealth Aluminum Concast (CAC), the originator of the ERCs. The change of ERC owner applications have subsequently been processed by the AQMD. Consequently, CAC certificate nos. AQ008497 – AQ008504 have been converted to CPP certificate nos. AQ009027, AQ009029, AQ009031, AQ009033, AQ009035, AQ009037, AQ009039, AQ009041. CAC certificate nos. In addition, CAC certificate nos. AQ008516 – AQ008523 have been converted to CPP certificate nos. AQ009043, AQ009045, AQ009047, AQ009049, AQ009051, AQ009053, AQ009055, AQ009057. Also, CAC certificate nos. AQ008682 – AQ008689 have been converted to CEC certificate nos. AQ009325, AQ009327, AQ009329, AQ009331, AQ009333, AQ009335, AQ009337, AQ009339. For the FDOC, Table 40C – ERC Certificate Nos. and History will be updated to reflect the processing of the change of ERC owner applications. These same comments apply to staff condition AQ-SC7.

The paragraph following Air Quality Table 20 states the actual offset ratio is 1.21:1 based on maximum annual PM_{10} emissions of 14,536 lbs/yr. Pg. 72 of the PDOC indicate the maximum annual emissions for all four turbines is 14,352 lbs/yr.

6. Pg. 4.1-43—Rule 407-Liquid and Gaseous Air Contaminants
The PSA states the CTGs would meet the BACT limit of 6.0 ppmvd @ 15 percent O2 for CO. Table 31—Simple Cycle Gas Turbine MSBACT/LAER Requirements on pg. 81 of the PDOC states the BACT emissions limit for CO is 4.0 ppmvd at 15% O_2, for this project. The District has sufficient test results for initial and periodic monitoring source testing for LM6000 turbines installed at existing power plants to demonstrate the 4.0 ppmvd to be achieved in practice.

7. Pg. 4.1-46—Regulation XVII-Prevention of Significant Deterioration (PSD)
The PSA states the District is not currently delegated authority for PSD permitting by U.S.EPA. As discussed on pp. 111-112 of the PDOC, on 7/25/07, the EPA and AQMD signed a new "Partial PSD Delegation Agreement."

8. Pg. 4.1-49—Condition A99.1 and A195.1
Pg. 4.1-60—CEC Condition AQ-2 (corresponds to A99.1)
Pg. 4.1-61—CEC Condition AQ-4 (corresponds to A195.1)
The PSA states condition A99.1 provides relief from the 2.3 ppm NOx limit during commissioning, startup and shutdown, and condition A195.1 provides the averaging time for the 2.3 ppm NOx. As stated in the PDOC, conditions A99.1 and A195.1 references the 2.5 ppm NOx BACT limit.

9. Pg. 4.1-60—CEC Condition AQ-3 (corresponds to A99.4 and A99.5)
The FDOC will revise condition A99.5 to reflect the correction of the turbine emission rate for NOx from 4.05 lb/hr to 3.98 lb/hr. The emission limit of 11.65 lbs/MMCF NOx applicable after commissioning will be changed to 11.53 lbs/mmcf.

10. Pg. 4.1-67—CEC Condition AQ-14 (corresponds to I296.1)
The FDOC will revise condition I296.1 to reflect the correction of the turbine emission rate for NOx from 4.05 lb/hr to 3.98 lb/hr. The RTCs required prior to the 1st year will change from 9,746 lbs/yr 9677 lbs/yr. The RTCs required prior to subsequent years will change from 6,960 lbs/yr 6886 lbs/yr.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT *ENGINEERING AND COMPLIANCE DIVISION*	PAGES 138	PAGE 1
	APPL. NO. 476650, -651, -654, -656, -657, -659, -660, -661, -663,-665, -666, 481185	DATE ~~16/2119/2009~~6/24/2009
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY

ENGINEERING EVALUATION
FOR A NEW 200 MW POWER PLANT

CANYON POWER PLANT
201 S. ANAHEIM BLVD.
ANAHEIM, CA 92805-3821

FACILITY ID: 153992

EQUIPMENT LOCATION: 3071 E. Miraloma Ave.
Anaheim, CA 92806-1809

Contact: Suzanne Wilson, City of Anaheim, 714-765-4112

EQUIPMENT DESCRIPTION

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE SPECIFIC RULES					
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, PORTABLE, ARCHITECTURAL COATING	E30			VOC: (9) [RULE 1113, 11-8-1996; RULE 1113, 7-13-2007; RULE 1171, 11-7-2003; RULE 1171, 2-1-2008]	K67.5
RULE 219 EXEMPT EQUIPMENT, HAND WIPING OPERATIONS	E32			VOC: (9) [RULE 1171, 11-7-2003; RULE 1171, 2-1-2008]	

* (1)	Denotes RECLAIM emission factor	(2)	Denotes RECLAIM emission rate
(3)	Denotes RECLAIM concentration limit	(4)	Denotes BACT emissions limit
(5)(5A)(5B)	Denotes command & control emission limit	(6)	Denotes air toxic control rule limit
(7)	Denotes NSR applicability limit	(8)(8A)(8B)	Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc)
(9)	See App B for Emission Limits	(10)	See Section J for NESHAP/MACT requirements

** Refer to Section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY CONDITIONS

F9.1 Except for open abrasive blasting operations, the operator shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated No. 1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or

(b) Of such opacity as to obscure an observer' s view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.

[RULE 401, 3-2-1984; RULE 401, 11-9-2001]

F14.1 The operator shall not use diesel fuel containing sulfur compounds in excess of 15 ppm by weight as supplied by the supplier.

Material safety data sheets for the diesel fuel shall be kept current and made available to District personnel upon request.

[RULE 431.2, 5-4-1990; RULE 431.2, 9-15-2000]

~~F24.1 Accidental release prevention requirements of Section 112(r)(7):~~

Formatted: Font color: Orange, Strikethrough

~~a). The operator shall comply with the accidental release prevention requirements pursuant to 40 CFR Part 68 and shall submit to the Executive Officer, as a part of an annual compliance certification, a statement that certifies compliance with all of the requirements of 40 CFR Part 68, including the registration and submission of a risk management plan (RMP).~~

~~b). The operator shall submit any additional relevant information requested by the Executive Officer or designated agency.~~

~~[RULE 40 CFR68 – Accidental Release Prevention, 5-24-1996]~~

DEVICE CONDITIONS

RULE 219 EXEMPT EQUIPMENT

K67.5 The operator shall keep records, in a manner approved by the district, for the following parameter(s) or item(s):

For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records for all coating consisting of (a) coating type, (b) VOC content as supplied in grams per liter (g/l) of materials for low-solids coatings, (c) VOC content as supplied in g/l of coating, less water and exempt solvent, for other coatings.

For architectural applications where thinners, reducers, or other VOC containing materials are added, maintain daily records for each coating consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 138	PAGE 3
ENGINEERING AND COMPLIANCE DIVISION	APPL. NO. 476650, -651, -654, -656, -657, -659, -660, -661, -663,-665, -666, 481185	DATE ~~16/2119/2009~~6/24/2009
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY

[~~RULE 1113, 11-8-1996; RULE 1113, 7-13-2007;~~ RULE 3004(a)(4) - Periodic Monitoring, 12-12-1997]

[Devices subject to this condition: E30]

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 1: POWER GENERATION					
SYSTEM 1: GAS TURBINES					
GAS TURBINE, NO. 1, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: 476651 GENERATOR, 50.95 MW	D1 [B2]	C3	NOX: MAJOR SOURCE	CO: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; CO: 4 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988] NOX: ~~80.26~~98.16 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; NOX: ~~11.5611.65~~ 11.53 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOX: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]; NOX: 25 PPMV NATURAL GAS (8) [40 CFR60 SUBPART KKKK, 7-6-2006] PM10: 0.1 GRAINS/SCF NATURAL GAS (5) [RULE 409, 8-7-1981]; PM10: 0.01 GRAINS/SCF NATURAL GAS (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 11 LBS/HR NATURAL GAS (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978] SO2: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997] SOX: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006] VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A63.1, ~~A63.2,~~ A99.1, A99.2, A99.3, A99.4, A99.5, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1 D29.2 D82.1 E193 I296.1, K40.1, K67.1
CO OXIDATION CATALYST, NO. 1, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME A/N: 476654	C3	D1 C4			

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

Formatted: Font color: Light Blue

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 138	PAGE 4
ENGINEERING AND COMPLIANCE DIVISION	APPL. NO. 476650, -651, -654, -656, -657, -659, -660, -661, -663,-665, -666, 481185	DATE ~~16/2119/2009~~6/24/2009
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
SELECTIVE CATALYTIC REDUCTION, NO. 1, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476654	C4	C3 S6		**NH3:** 5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.4, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
AMMONIA INJECTION	[B5]				
STACK, TURBINE NO. 1, HEIGHT: 86 FT; DIAMETER: 11 FT 8 IN A/N: 476651	S6	C4			
GAS TURBINE, NO. 2, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: 476656	D7	C9	NOX: MAJOR SOURCE	**CO:** 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; **CO:** 4 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988] **NOX:** ~~80.26~~98.16 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **NOX:** ~~11.5611.65~~ 11.53 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; **NOX:** 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]; **NOX:** 25 PPMV NATURAL GAS (8) [40 CFR60 SUBPART KKKK, 7-6-2006] **PM10:** 0.1 GRAINS/SCF NATURAL GAS (5) [RULE 409, 8-7-1981]; **PM10:** 0.01 GRAINS/SCF NATURAL GAS (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **PM10:** 11 LBS/HR NATURAL GAS (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978] **SO2:** (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997] **SOX:** 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006] **VOC:** 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A63.1, ~~A63.2,~~ A99.1, A99.2, A99.3, A99.4, A99.5, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1, D29.2, D82.1, E193.1, H23.1, I296.1, K40.1, K67.1
GENERATOR, 50.95 MW	[B8]				
CO OXIDATION CATALYST, NO. 2, BASF, 110 CUBIC FEET OF TOTAL CATALYST VOLUME	C9	D7 C10			

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
A/N: 476657					
SELECTIVE CATALYTIC REDUCTION, NO. 2, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476657 AMMONIA INJECTION	C10 [B11]	C9 S12		NH3: 5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.4, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 2, HEIGHT: 86 FT; DIAMETER: 11 FT 8 IN A/N: 476656	S12	C10			
GAS TURBINE, NO. 3, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: 476659 GENERATOR, 50.95 MW	D13 [B14]	C15	NOX: MAJOR SOURCE	CO: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; CO: 4 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988] NOX: ~~80.26~~98.16 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; NOX: ~~11.56~~11.65 11.53 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; NOX: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]; NOX: 25 PPMV NATURAL GAS (8) [40 CFR60 SUBPART KKKK, 7-6-2006] PM10: 0.1 GRAINS/SCF NATURAL GAS (5) [RULE 409, 8-7-1981]; PM10: 0.01 GRAINS/SCF NATURAL GAS (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 11 LBS/HR NATURAL GAS (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978] SO2: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997] SOX: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006] VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A63.1, ~~A63.2,~~ A99.1, A99.2, A99.3, A99.4, A99.5, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1 D29.2 D82.1 E193 I296.1, K40.1, K67.1
CO OXIDATION CATALYST, NO. 3, BASF, 110 CUBIC FEET OF TOTAL CATALYST	C15	D13 C16			

Formatted: Font color: Red

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 138	PAGE 6
ENGINEERING AND COMPLIANCE DIVISION	APPL. NO. 476650, -651, -654, -656, -657, -659, -660, -661, -663,-665, -666, 481185	DATE ~~16/2119/2009~~6/24/2009
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
VOLUME A/N: 476660					
SELECTIVE CATALYTIC REDUCTION, NO. 3, CORMETECH CMHT-21, 1012 CU. FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476660 AMMONIA INJECTION	C16 [B17]	C15 S18		NH3: 5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.4, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 3, HEIGHT: 86 FT; DIAMETER: 11 FT 8 IN A/N: 476659	S18	C16			
GAS TURBINE, NO. 4, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000PC SPRINT, SIMPLE CYCLE, 479 MMBTU/HR AT 46 DEG F, WITH INLET CHILLING, WITH WATER INJECTION WITH A/N: 476661 GENERATOR, 50.95 MW	D19 [B20]	C21	NOX: MAJOR SOURCE	**CO**: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; **CO**: 4 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988] **NOX**: ~~80.26~~98.16 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]; **NOX**: ~~11.56~~~~11.65~~ 11.53 LBS/MMSCF NATURAL GAS (1A) [RULE 2012, 5-6-2005]; **NOX**: 2.5 PPMV NATURAL GAS (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]; **NOX**: 25 PPMV NATURAL GAS (8) [40 CFR60 SUBPART KKKK, 7-6-2006] **PM10**: 0.1 GRAINS/SCF NATURAL GAS (5) [RULE 409, 8-7-1981]; **PM10**: 0.01 GRAINS/SCF NATURAL GAS (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; **PM10**: 11 LBS/HR NATURAL GAS (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978] **SO2**: (9) [40CFR 72 – Acid Rain Provisions, 11-24-1997] **SOX**: 0.06 LBS/MMBTU NATURAL GAS (8) [40CFR 60 Subpart KKKK, 7-6-2006] **VOC**: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A63.1, ~~A63.2,~~ A99.1, A99.2, A99.3, A99.4, A99.5, A195.1, A195.2, A195.3, A327.1, B61.1, D12.1 D29.2 D82.1 E193 I296 K67.1
CO OXIDATION CATALYST, NO. 4, BASF, 110 CUBIC FEET	C21	D19 C22			

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

Formatted: Font color: Red

Formatted: Font color: Light Blue

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
OF TOTAL CATALYST VOLUME A/N: 476663					
SELECTIVE CATALYTIC REDUCTION, NO. 4, CORMETECH CMHT-21, 1012 CU.FT.; WIDTH: 2 FT 6 IN; HEIGHT: 25 FT 9 IN; LENGTH: 18 FT WITH A/N: 476663 AMMONIA INJECTION	C22 [B23]	C21 S24		NH3: 5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.4, D12.2, D12.3, D12.4, E179.1, E179.2, E193.1
STACK, TURBINE NO. 4, HEIGHT: 86 FT; DIAMETER: 11 FT 8 IN A/N: 476661	S24	C22			
SYSTEM 2: INTERNAL COMBUSTION ENGINE					
INTERNAL COMBUSTION ENGINE, EMERGENCY POWER, DIESEL FUEL, CATERPILLAR, MODEL C-27, WITH AFTERCOOLER, TURBOCHARGER, 1141 BHP WITH A/N: 476666 FILTER, DIESEL PARTICULATES, CLEANAIR SYSTEMS PERMIT, MODEL FDA225, WITH HIBACK DATA LOGGING AND ALARM SYSTEM GENERATOR, 750 KW	D25 [B26] [B27]		NOX: PROCESS UNIT**	CO: 2.6 GRAM/BHP-HR DIESEL (4) [RULE 1703(a)(2)-PSD-BACT, 10-7-1988] NOX: 225.48 LBS/1000 GAL DIESEL (1) [RULE 2012, 5-6-2005] NOX + ROG: 4.8 GRAM/BHP-HR DIESEL (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005] PM10: 0.15 GRAM/BHP-HR DIESEL (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002] SOX: 0.005 GRAM/BHP-HR DIESEL (4) [RULE 1303(a)(1)-BACT, 5-10-1996, RULE 1303(a)(1), 12-6-2002]	C1.1, D12.5, E193.1, E193.2, E193.3, I296.2, K67.2, K67.3
SYSTEM 3: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, ~~FIXED ROOF~~ PRESSURE VESSEL, 19 PERCENT AQUEOUS AMMONIA, 10,000 GALS; DIAMETER: 7 FT; LENGTH: 42 FT A/N: 476665	D28				C157.1, E144.1, E193.1, K67.4
PROCESS 2: OIL WATER SEPARATION					
OIL WATER SEPARATOR, UNDERGROUND, EMULSIFIED OIL AND	D29				E193.1

Formatted: Font color: Red, Strikethrough

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
WATER, 550 GALS; DIAMETER: 3 FT 6 IN; LENGTH: 7 FT 9 IN A/N: 481185					

* (1)	Denotes RECLAIM emission factor	(2)	Denotes RECLAIM emission rate
(3)	Denotes RECLAIM concentration limit	(4)	Denotes BACT emissions limit
(5)(5A)(5B)	Denotes command & control emission limit	(6)	Denotes air toxic control rule limit
(7)	Denotes NSR applicability limit	(8)(8A)(8B)	Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc)
(9)	See App B for Emission Limits	(10)	See Section J for NESHAP/MACT requirements

** Refer to Section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

DEVICE CONDITIONS

GAS TURBINES

A63.1 The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
VOC	Less than or equal to ~~368~~129 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to ~~883~~299 LBS IN ANY CALENDAR MONTH
SOx	Less than or equal to ~~100~~34 LBS IN ANY CALENDAR MONTH

For the purposes of this condition, the above emission limits shall be based on the emissions from a single turbine.

The turbine shall not commence with normal operation until the commissioning process has been completed. Normal operation commences when the turbine is able to supply electrical energy to the power grid as required under contract with the relevant entities. The District shall be notified in writing once the commissioning process for each turbine is completed.

Normal operation may commence in the same calendar month as the completion of the commissioning process provided the turbine is in compliance with the above emission limits.

The operator shall calculate the monthly emissions for VOC, PM10, and SOx using the equation below.

Monthly Emissions, lb/month = (Monthly fuel usage in mmscf/month) * (Emission factors indicated below)

For commissioning, the emission factors shall be as follows: VOC, ~~2.31~~ 3.76 lb/mmcf; PM10, ~~10.91~~6.03 lb/mmcf; and SOx, ~~2.33~~0.68 lb/mmcf.

For normal operation, the emission factors shall be as follows: VOC, 2.59 lb/mmcf; PM10, 6.03 lb/mmcf; and SOx, 0.68 lb/mmcf.

For a month during which both commissioning and normal operation take place, the monthly emissions shall be the total of the commissioning emissions and the normal operation emissions.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition: D1, D7, D13, D19]

~~A63.2 The operator shall limit emission from this equipment as follows:~~

~~CONTAMINANT~~	~~EMISSION LIMIT~~
~~VOC~~	~~Less than or equal to 859 LBS IN ANY ONE YEAR~~
~~PM10~~	~~Less than or equal to 1996 LBS IN ANY ONE YEAR~~
~~SOX~~	~~Less than or equal to 272 LBS IN ANY ONE YEAR~~

~~For the purposes of this condition, the above limits shall be based on the emissions from a single turbine.~~

~~The operator shall calculate the monthly emissions for VOC, PM10, and SOx using the equation below.~~

~~Monthly Emissions, lb/month = (Monthly fuel usage in mmscf/month) * (Emission factors indicated below)~~

~~For commissioning, the emission factors shall be as follows: VOC, 2.31 lb/mmcf; PM10, 10.91 lb/mmcf; and SOx, 2.33 lb/mmcf.~~

~~For normal operation, the emission factors shall be as follows: VOC, 2.59 lb/mmcf; PM10, 6.03 lb/mmcf; and SOx, 0.68 lb/mmcf.~~

~~For a month during which both commissioning and normal operation take place, the monthly emissions shall be the total of the commissioning emissions and the normal operation emissions.~~

~~For the purposes of this condition, the annual emission limit shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12 month period beginning on the first day of each calendar month.~~

~~[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]~~

~~[Devices subject to this condition: D1, D7, D13, D19]~~

A99.1 The 2.5 PPM NOx emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. Commissioning shall not exceed 156 hours total. Each start-up shall not exceed 35 minutes. Each shutdown shall not exceed 10 minutes. The turbines shall be limited to a maximum of ~~129~~ 240 start-ups per year.

NOx emissions for an hour that includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence shall not exceed 14.27 lbs, and for the hour which includes a shutdown 4.07 lbs.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

For the purposes of this condition, start-up shall be defined as the start -up process to bring the turbine to full successful operation.

[RULE 1703(a)(2) – PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

A99.2 The 4.0 PPM CO emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. Commissioning shall not exceed 156 hours total. Each start-up shall not exceed 35 minutes. Each shutdown shall not exceed 10 minutes. The turbine shall be limited to a maximum of ~~129~~ 240 start-ups per year.

CO emissions for an hour that includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence shall not exceed 6.3 lbs, and for the hour which includes a shutdown 4.15 lbs.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

For the purposes of this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

[RULE 1703(a)(2) – PSD-BACT, 10-7-1988]

[Devices subject to this condition: D1, D7, D13, D19]

A99.3 The 2.0 PPM ROG emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. Commissioning shall not exceed 156 hours total. Each start-up shall not exceed 35 minutes. Each shutdown shall not exceed 10 minutes. The turbine shall be limited to a maximum of ~~129~~ 240 start-ups per year.

ROG emissions for an hour that includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence shall not exceed 1.29 lbs, and for the hour which includes a shutdown 1.27 lbs.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

For the purposes of this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D1, D7, D13, D19]

A99.4 The ~~80.26~~ 98.16 LBS/MMCF NOx emission limit(s) shall only apply during turbine commissioning during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

A99.5 The ~~11.56~~ ~~11.65~~ 11.53 LBS/MMCF NOx emission limit(s) shall only apply after turbine commissioning during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.

[RULE 2012, 5-6-2005]

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

Formatted: No underline

Formatted: Font color: Red

[Devices subject to this condition: D1, D7, D13, D19]

A195.1 The 2.5 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.

[RULE 1703(a)(2) – PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

A195.2 The 4.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.

[RULE 1703(a)(2) – PSD-BACT, 10-7-1988]

[Devices subject to this condition: D1, D7, D13, D19]

A195.3 The 2.0 PPMV ROG emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D1, D7, D13, D19]

A327.1 For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.

[RULE 475, 10-8-1976; RULE 475, 8-7-1978]

[Devices subject to this condition: D1, D7, D13, D19]

B61.1 The operator shall not use natural gas containing the following specified compounds:

Compound	Range	Grain per 100 scf
H2S	Greater than	0.25

This concentration limit is an annual average based on monthly samples of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H2S.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition: D1, D7, D13, D19]

D12.1 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the turbine.

The operator shall also install and maintain a device to continuously record the parameter being measured.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 2012, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

D29.1 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOX emissions	AQMD Laboratory Method 307-91	Not Applicable	Fuel sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District Method 5	4 hours	Outlet of the SCR serving this equipment
NH3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted after AQMD approval of the source test protocol, but no later than 180 days after initial start-up. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted when this equipment is operating at loads of 100, 75, and 50 percent, with the exception of PM10 testing. For PM10, the test shall be conducted when this equipment is operating at a load of 100 percent.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with preconcentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.

For the purpose of this condition, alternative test method may be allowed for each of the above pollutants upon concurrence of AQMD, EPA and CARB.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

D29.2 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

The test(s) shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

If the turbine is not in operation during one quarter, then no testing is required during that quarter.

The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted and the results submitted to the District within ~~45~~ ~~45~~ 60 days after the test date.

Formatted: Font color: Orange, Strikethrough

Formatted: Font color: Orange

Formatted: Font color: Orange, Strikethrough

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D1, D7, D13, D19]

D29.3 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	AQMD Laboratory Method 307-91	Not Applicable	Fuel sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District Method 5	4 hours	Outlet of the SCR serving this equipment

The test shall be conducted at least once every three years. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at loads of 100, 75, and 50 percent, with the exception of PM10 testing. For PM10, the test shall be conducted when this equipment is operating at a load of 100 percent.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with preconcentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.

For the purposes of this condition, alternative test method may be allowed for each of the above pollutants upon concurrence of AQMD, EPA, and CARB.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]

[Devices subject to this condition: D1, D7, D13, D19]

D82.1 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 90 days after initial startup of the turbine, in accordance with an approved AQMD Rule 218 CEMS plan application.

The operator shall not install the CEMS prior to receiving initial approval from AQMD. Within two weeks of the turbine start-up, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operated to measure CO concentrations over a 15 minute averaging time period.

[RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 218, 8-7-1981; RULE 218, 5-14-1999]

[Devices subject to this condition: D1, D7, D13, D19]

D82.2 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start-up of the turbine.

[RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005; RULE 2012, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 07-AFC-9 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, C4, D7, C10, D13, C16, D19, C22, D25, D28, D29]

H23.1 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart

NOx	40CFR60, SUBPART	KKKK
SOX	40CFR60, SUBPART	KKKK

[40 CFR 60 Subpart KKKK, 7-6-2006]

[Devices subject to this condition: D1, D7, D13, D19]

I296.1 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall prior to the 1st compliance year hold a minimum NOx RTCs of ~~66409746~~ 9677 lbs/yr. This condition shall apply during the 1st 12 months of operation, commencing with the initial operation of the gas turbine.

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the 1st compliance year, hold a minimum of ~~38296960~~ 6886 lbs/yr of NOx RTCs for the operation of the gas turbine.

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

Formatted: Font color: Red

In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.

The condition shall apply to each turbine individually.

[RULE 2005, 5-6-2007]

[Devices subject to this condition: D1, D7, D13, D19]

K40.1 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the heating content of the fuel, the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

K67.1 The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use during the commissioning period.

Natural gas fuel use after the commissioning period and prior to CEMS certification.

Natural gas fuel use after CEMS certification.

[RULE 2005, 5-6-2005]

[Devices subject to this condition: D1, D7, D13, D19]

SCR/CO CATALYSTS

A195.4 The 5 PPMV NH3 emission limit(s) is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following equation.

NH3 (ppmv) = [a-b*c/1E+06]*1E+06/b; where

a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at 15% O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

The operator shall use the above described method or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.

[RULE 1303(a)(1) – BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: C4, C10, C16, C22]

D12.2 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The calibration records shall be kept on site and made available to District personnel upon request.

The ammonia injection system shall be placed in full operation as soon as the minimum temperature at the outlet to the SCR reactor is reached. The minimum temperature is 540 deg F.

The ammonia injection rate shall remain between 6.83 gal/hr and 16 gal/hr.

[RULE 1303(a)(1) – BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: C4, C10, C16, C22]

D12.3 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature of the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The catalyst temperature range shall remain between 665 deg F and 870 deg F.

The catalyst inlet temperature shall not exceed 870 deg F.

The temperature range requirement of this condition shall not apply during start-up conditions of the turbine not to exceed 35 minutes per start-up. For this condition, start-up shall be defined as the start-up process to bring the turbine to full successful operation.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]

[Devices subject to this condition: C4, C10, C16, C22]

D12.4 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure drop across the catalyst shall not exceed 6 inches water column.

[RULE 1303(a)(1) – BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]

[Devices subject to this condition: C4, C10, C16, C22]

E179.1 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number D12-2
Condition Number D12-3

[RULE 1303(a)(1) – BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]

[Devices subject to this condition: C4, C10, C16, C22]

E179.2 For the purpose of the following condition number(s), continuous record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number: D12-4

[RULE 1303(a)(1) – BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; RULE 2005, 5-6-2005]

[Devices subject to this condition: C4, C10, C16, C22]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 07-AFC-9 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, C4, D7, C10, D13, C16, D19, C22, D25, D28, D29]

BLACK START ENGINE

C1.1 The operator shall limit the operating time to no more than 200 hour(s) in any one year.

The 200 hours in any one year shall include no more than 50 hours for maintenance and performance testing.

The duration of each test shall not exceed 38 minutes in any one hour.

[RULE 1110.2, 2-1-2008; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1401, 3-7-2008; RULE 1470, 6-1-2007; RULE 2012, 5- 6-2005; CA PRC CEQA, 11-23-1970; CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D25]

D12.5 The operator shall install and maintain a(n) non-resettable elapsed time meter to accurately indicate the elapsed operating time of the engine.

[RULE 1110.2, 2-1-2008; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1401, 3-7-2008; RULE 1470, 6-1-2007; RULE 2012, 5- 6-2005]

[Devices subject to this condition: D25]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 07-AFC-9 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, C4, D7, C10, D13, C16, D19, C22, D25, D28, D29]

E193.2 The operator shall operate and maintain this equipment according to the following requirements:

The operation of this engine beyond the 50 hours per year allotted for maintenance and performance testing shall be allowed only in the event of a loss of grid power or up to 30 minutes prior to a rotating outage, provided that the utility distribution company has ordered rotating outages in the control area where the engine is located or has indicated that it expects to issue such an order at a certain time, and the engine is located in a utility service block that is subject to the rotating outage.

Engine operation shall be terminated immediately after the utility distribution company advises that a rotating outage is no longer imminent or in effect.

This engine shall be operated for the primary purpose of providing a back up source of power to start a turbine.

[RULE 1110.2, 2-1-2008; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1401, 3-7-2008; RULE 1470, 6-1-2007; RULE 2012, 5- 6-2005]

[Devices subject to this condition: D25]

E193.3 The operator shall operate and maintain this equipment according to the following specifications:

The operator shall operate the diesel particulate filter system only with an operational HiBACK data logging and alarm system with backpressure and temperature monitors.

The HiBACK data logging and alarm system shall be programmed to provide a red warning signal and an audible alarm, whenever the engine backpressure reaches the maximum allowable backpressure of 40 inches of water. The engine backpressure shall not exceed 40 inches of water in operation.

The engine shall be operated at the load level required to achieve an engine exhaust gas temperature of 572 deg F (300 deg C) for passive regeneration of the diesel particulate filter for at least 30% of the operating time~~ or two hours, whichever is longer~~.

The engine shall not be operated below the passive regeneration temperature of 572 deg F for more than 240 consecutive minutes.

The operator shall regenerate the diesel particulate filter after every 12 cold starts or whenever a yellow warning signal indicating the backpressure is 10% below the maximum allowable backpressure of 40 inches of water is received from the HiBACK alarm system, whichever occurs first. Filter ~~In order to achieve filter regeneration, the operator shall operate the engine at the load required to achieve an exhaust temperature above 572 deg F until~~ regeneration is complete when the backpressure monitoring system indicates a normal backpressure reading.

The engine shall be shut down and the diesel particulate filter shall be cleaned whenever the backpressure reaches the maximum backpressure limit of 40 inches water. Cleaning shall be performed according to the manufacturer's recommendations in the installation and maintenance manual.

After every 200 hours of normal engine operation, the operator shall inspect the integrity of the diesel particulate filter and, if necessary, replace it.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D25]

I296.2 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall prior to the 1st compliance year hold a minimum NOx RTCs of 2412 lbs/yr. This condition shall apply during the 1st 12 months of operation, commencing with the initial operation of the black start engine.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the 1st compliance year, hold a minimum of 2412 lbs/yr of NOx RTCs for operation of the black start engine.

In accordance with Rule 2005(f), unused RTC's may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.

[RULE 2005, 5-6-2005]

[Devices subject to this condition: D25]

K67.2 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

An engine operating log shall be maintained which on a monthly basis shall list all engine operations in each of the following areas:

A. Emergency use hours of operation,

B. Maintenance and testing hours, and

C. Other operating hours, with a description of the reason for operation.

In addition, each time the engine is started manually, the log shall include the date of operation and the timer reading in hours at the beginning and end of operation. The log shall be kept for a minimum of five calendar years prior to the current year and made available to District personnel upon request. The total hours of operation for the previous calendar year shall be recorded some time during the first 15 days of January each year.

[RULE 1110.2, 2-1-2008]

[Devices subject to this condition: D25]

K67.3 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

The operator shall maintain records of diesel particulate filter inspections, replacements, and cleaning.

The operator shall maintain monthly records of the exhaust temperature, engine backpressure, and date and time for the duty cycle of the engine as downloaded from the HiBACK data logging and alarm system.

All records shall be maintained on file for a minimum of five years and made available to District personnel upon request.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D25]

AMMONIA TANK

C157.1 The operator shall install and maintain a pressure relief valve set at 25 psig.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D28]

E144.1 The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D28]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 07-AFC-9 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, C4, D7, C10, D13, C16, D19, C22, D25, D28, D29]

K67.4 The operator shall keep records in a manner approved by the Executive Officer, for the following parameter(s) or item(s):

The operator shall document an inspection each time the tank is filled to ensure the vapor recovery equipment is consistently and properly used.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D28]

OIL WATER SEPARATOR

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 07-AFC-9 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, C4, D7, C10, D13, C16, D19, C22, D28]

BACKGROUND AND FACILITY DESCRIPTION

Background

The Southern California Public Power Authority (SCPPA) is proposing to install a new natural gas fired peaker power plant, Canyon Power Plant (CPP), nominally rated at 200 megawatts. SCPPA is a consortium of municipalities and an irrigation district established by a Joint Powers Agreement to develop, construct, and operate electric generation and transmission projects. SCPPA will be the owner, but the City of Anaheim (COA), the sole participating member city, will be the operator.

The CPP will be strictly dedicated for generating power to serve the COA's retail customers. Current load/resource balances for the COA show a significant power shortage during the summer period. As a result the output will be utilized to serve native load within the COA and to meet resource adequacy requirements.

Facility Description

The new power plant will consist of four (4) identical combustion-turbine-generators (CTGs) for a total rated peak generating capacity of 1916 MMBTU/hr at 46 °F. The gas turbines will be General Electric LM6000PC Sprint units. Each turbine will drive a generator rated at 50.95 MW.

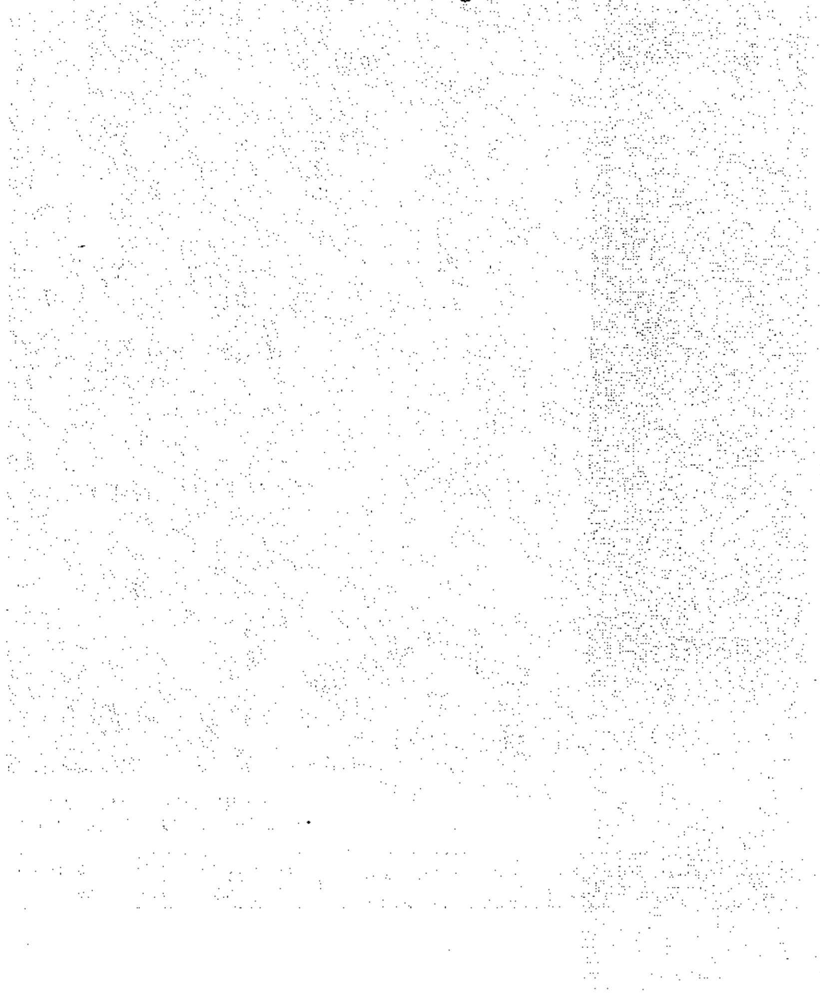
Each of the proposed CTGs will be configured in simple cycle; therefore, there will be no heat recovery steam generators (HRSG), duct burners, or steam turbines used at this plant. The net power generated, after deducting auxiliary power consumption, will be derived solely from the four generators. Four identical selective catalytic reduction (SCR) systems and CO oxidation catalysts will be utilized for control of NOx and CO emissions, respectively. One 10,000 gallon ammonia (NH_3) storage tank will store 19% aqueous ammonia which is part of the SCR process. A 4-cell mechanical draft evaporative chiller cooling tower will provide evaporative cooling for the inlet air to the CTGs to augment power production, and will operate during all hours of normal CTG operation. An 1141 bhp diesel emergency internal combustion engine (black start engine) will be used to start up the plant in the event of a loss of grid power. An oil water separator will be used to collect equipment washwater and rainfall.

Proposed Site

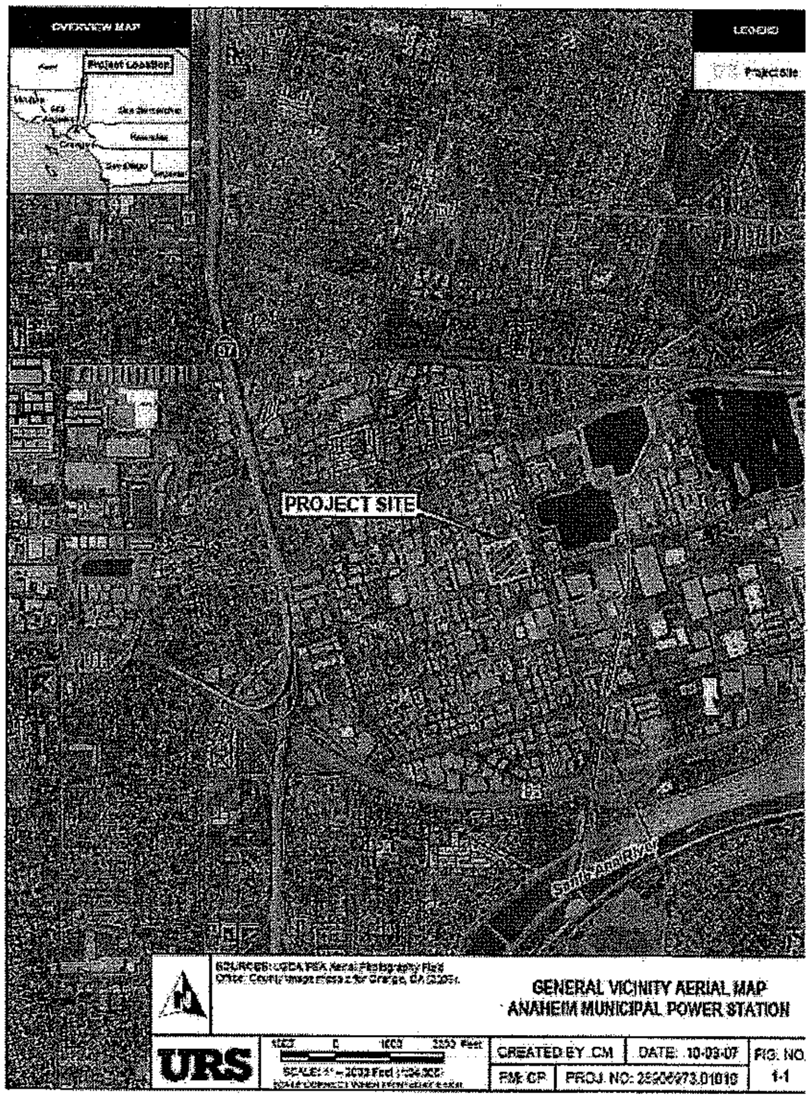
The proposed site is in northeastern Anaheim at 3071 E. Miraloma Avenue. The 9-acre site is located approximately 3.25 miles northeast of downtown Anaheim and 25 miles southeast of downtown Los Angeles. The vicinity of the proposed project is a developed, industrial area within Orange County. The principal land use for the site was food catering for a truck fleet, formerly operated by Orange County Food Service. The on-site structures, including the kitchen/warehouse building and maintenance garage, will be demolished as part of the CPP project.

The project site is located in a commercial and industrial area. To the east are several groundwater recharge facilities, including Kraemer Basin, operated and maintained by the OCWD. Aldelphia has a communication tower located within the parcel immediately west of the site. A fast food restaurant is located at the northwest corner of Kraemer Boulevard and East Miraloma Avenue. Four residential units are located approximately 1,200-2,130 feet from the center of the site. The closest residential unit is located approximately 1,200 feet west of the center of the site. The closest residential complex is 2,350 feet from the site and located on the southeast corner of Kramer Boulevard and Orangethorpe Avenue.

Below are the general vicinity aerial map for the proposed site, and a site plan showing the equipment layout.

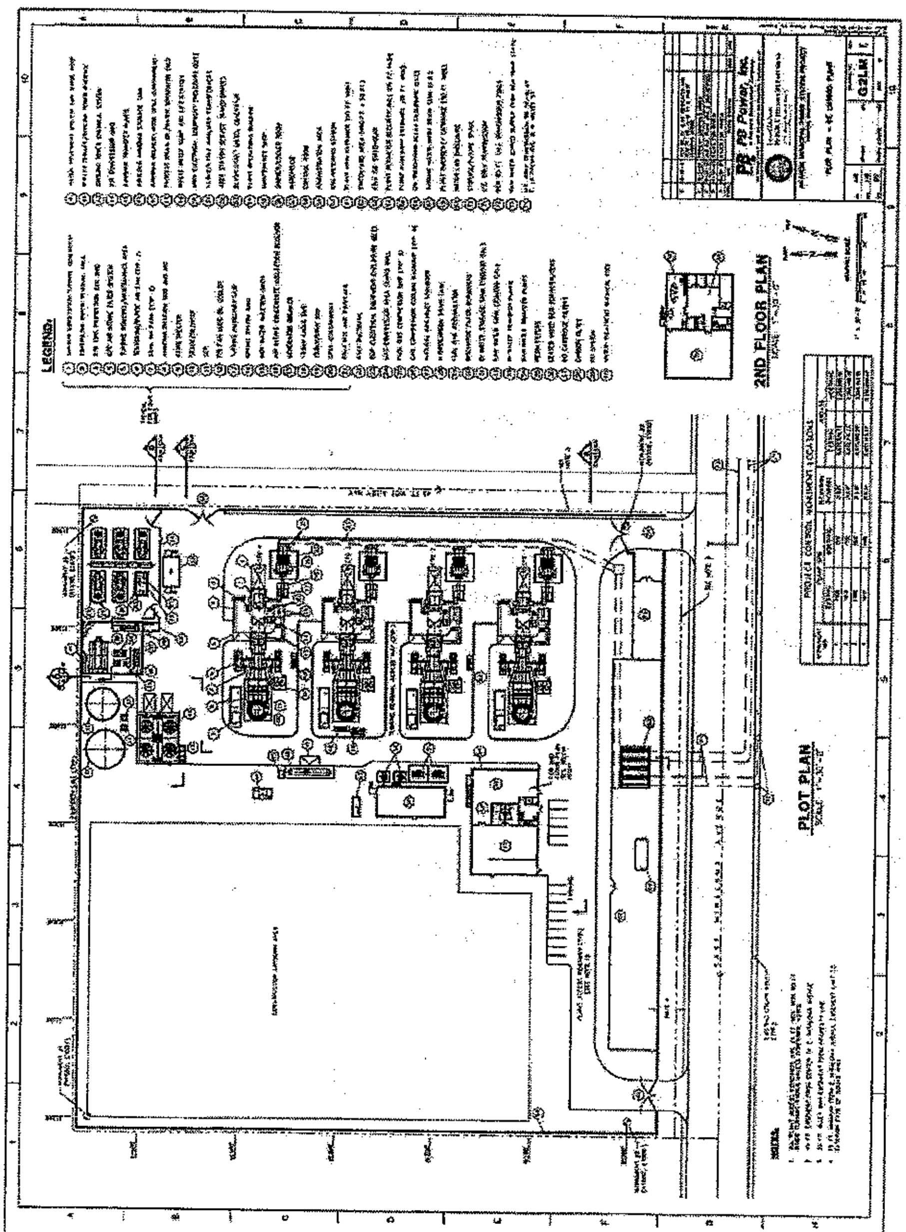


SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 138	PAGE 29
ENGINEERING AND COMPLIANCE DIVISION	APPL. NO. 476650, -651, -654, -656, -657, -659, -660, -661, -663,-665, -666, 481185	DATE ~~16/2119/2009~~6/24/2009
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY



layout..ut.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 138	PAGE 30
ENGINEERING AND COMPLIANCE DIVISION	APPL. NO. 476650, -651, -654, -656, -657, -659, -660, -661, -663,-665, -666, 481185	DATE ~~16/2119/2009~~6/24/2009
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY



<u>California Energy Commission</u>
The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger, including any related facilities such as transmission lines, fuel supply lines, and water pipelines. The CEC's 12-month permitting process is a certified regulatory program under the California Environmental Quality Act (CEQA) and includes various opportunities for public and inter-agency participation. The CEC's certification process subsumes all requirements of local, regional, state, and federal agencies required for the construction of a new plant. The CEC coordinates its review of the proposed facility with the agencies that will be issuing permits to ensure that its certification incorporates the conditions that are required by these various agencies. As the CPP will be rated at greater than 50 megawatts, it is subject to the CEC's 12-month certification process. As part of this process, SCPPA submitted an application for certification ("AFC") (07-AFC-9) to the CEC on December 28, 2007 seeking certification for the new power plant.

<u>District Applications Submitted</u>
In addition to the CEC certification process, SCPPA submitted the following applications to the District seeking Permits to Construct for the new power plant. (URS Corp. provided support in drafting the applications submitted to the CEC and the District.)

Table 1 - Applications for Permits to Construct Submitted to AQMD

Application No.	Submittal Date	Data Adequacy Date	Equipment Description	Rule 301 Schedule	Permit Processing Fee Submitted
476650	12/26/07	3/11/08	Initial Title V (1-20 devices)	N/A	$ 1,219.20
476651—**MASTER FILE**	12/26/07	3/11/08	GE LM6000PC Sprint Gas Turbine #1	D	$ 4071.37
476654	12/26/07	3/11/08	SCR/CO Oxidation Catalyst #1	C	$ 2,949.92
476656	12/26/07	3/11/08	GE LM6000PC Sprint Gas Turbine #2	D	$ 2035.69 (50%--identical)
476657	12/26/07	3/11/08	SCR/CO Oxidation Catalyst #2	C	$ 1474.96 (50%--identical)
476659	12/26/07	3/11/08	GE LM6000PC Sprint Gas Turbine #3	D	$ 2035.69 (50%--identical)
476660	12/26/07	3/11/08	SCR/CO Oxidation Catalyst #3	C	$ 1474.96 (50%--identical)
476661	12/26/07	3/11/08	GE LM6000PC Sprint Gas Turbine #4	D	$ 2035.69 (50%--identical)
476663	12/26/07	3/11/08	SCR/CO Oxidation Catalyst #4	C	$ 1474.96 (50%--identical)
476665	12/26/07	3/11/08	Ammonia Storage Tank	A	$ 1,170.20
476666	12/26/07	3/11/08	Emergency ICE (Black Start Engine)	B	$ 1,865.02
481185	4/9/08	4/24/08	Oil Water Separator	B	$ 1,865.02
				Total	$ 23,672.67

The cooling tower is exempt from permitting pursuant to Rule 219(d)(3), which exempts water cooling towers not used for evaporative cooling of process water or not used for evaporative cooling of water from barometric jets or from barometric condensers and in which no chromium compounds are contained. (A check for $23,672.67 was submitted on 12/26/07, and a check for $1865.02 was submitted on 4/9/08. The check for $23,672.67 included an overpayment of $1,865.02 for the exempt cooling tower, which was refunded.)

Table 1B—Fees in Addition to Permit Processing Fees

Description of Fees	Amount	Explanation
Air Quality Analysis and Health Risk Assessment (charged to A/N 476651)	$12,534.32~~6176.50~~	Rule 301 Table IIA—For Schedule D equipment (CTGs), the fee is $3,926.52 + T&M. T&M = Time and Material charged at $112.30 per hour above 35 hours. Air Quality Modeling Protocol review is 10 hours, and Air Quality Analysis and Health Risk Assessment Review (~~two~~ three submittals) is ~~80~~120 hours, for total of ~~90~~130 hours. $3926.52 + [(~~90~~130 hr – 35 hr) x $112.30/ hr] = $14,595.02. However, Table IIA states that the total combined fee for these reviews shall not exceed $12,534.32.~~6176.50~~
Public Notice Preparation and Publication (charged to A/N 476651)	$1,397.57	Rule 301 Table IIB—Footnote (a) states if Rule 212(g) and Title V notices are combined, pursuant to Rule 212(h), only Rule 212(g) publication fee applies. For Orange County, the fee for Rule 212(g) Notice is $1,397.57.
Title V Final Fee (charged to A/N 476650)	$804.60	Rule 301(l)(3)(B) Title V FINAL Fee Table—For 1-20 devices (counting C and D devices only), for time spent in excess of 8 hours, for work on or after July 1, 2008, the fee is $134.10/hr, up to a maximum total fee of $16,371.06. For the engineering evaluation and facility permit program input, the total hours spent to date are 14 hours. [(14 hr – 8 hr) x $134.10/hr = $804.60] *This is not the final total.*
Total	$14,736.49~~8378.67~~	

Changes of Project Scope

The original scope of the applications, dated 12/26/07, required the access of PM_{10} priority reserve credits from the Priority Reserve, which is governed by Rule 1309.1—Priority Reserve, amended August 3, 2007, because the facility-wide PM_{10} emissions would have been greater than 4 TPY. VOC and SOx would have been exempt from requiring offsets pursuant to the Rule 1304 offset exemption for facility-wide emissions of VOC and SOx less than 4 TPY. At the time of submittal of the applications, the adoption of ~~this~~ the latest amendment to Rule 1309.1 was under litigation. On July 28, 2008, the Superior Court of the State of California issued a writ of mandate vacating the District's approval of the Rule 1309.1 amendment and enjoining the District from undertaking any action to further implement these rules pending CEQA compliance. ~~Due to~~ Because of the legal issues surrounding Rule 1309.1, the access of PM_{10} priority reserve credits no longer appeared to be a viable option for the CPP project. Accordingly, the applicant proposed to reduce the annual operating hours and make other emissions related changes to reduce the annual PM_{10} emissions to below 4 TPY, thereby exempting the need for PM_{10} offsets pursuant to the Rule 1304 offset exemption for facility-wide emissions of PM_{10} less than 4 TPY.

On September 12, 2008, the applicant submitted a "Revised Permit to Construct/Permit to Operate Application for the Canyon Power Plant," dated September 2008, including revised modeling that superseded all prior modeling, to reflect the reduced project scope ("revised Application"). A letter, dated 9/18/08, was submitted by Steve Sciortino, the Integrated Resources Manager for the City of Anaheim Public Utilities Department and the responsible official for this project, formally requesting a change in scope to reduce the hours of operation.

Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Font: Not Bold

On October 30, 2008, the draft PDOC was sent to the applicant for preliminary review prior to commencement of the CEC, Title V and Rule 212(g) agency review and public notice periods. On November 5, 2008, the applicant was informed that a further development of the Superior Court decision was that the District cannot issue permits using any Rule 1304 offset exemptions, including the exemption for facility-wide emissions of VOC, SOx, and PM_{10} less than 4 TPY. Consequently, the draft PDOC was placed on hold until the applicant agreed to provide emission reduction credits (ERCs) for these pollutants.

Formatted: Font: (Default) Times New Roman, 11 pt, Font color: Auto, Subscript

On November 14, 2008, the applicant met with District staff and legal counsel to discuss the impact of this latest legal development on the project. The applicant was informed that before the District may proceed with the draft PDOC, a letter from the City of Anaheim will be required that indicated it intended to purchase and has included in its budget the funds to purchase the required ERCs and that it has arranged with specific sellers for the purchase of these ERCs. If the applicant proposes to make changes to the emissions, additional modeling would not be required if the proposed changes would result in decreased emission concentrations and decreased toxic risk compared to the previous evaluation.

On November 26, 2008, Mr. Sciortino submitted a letter formally requesting a second change in scope to further reduce the hours of operation and number of startups/shutdowns ("second revised Application") to minimize the number of ERCs that would be required. In addition, he submitted a marked up copy of the draft PDOC that had been sent to them for review on October 29, 2008.

The proposed scope will result in an increase in annual emissions for the turbines and cooling tower because annual operating hours will increase. For the previous project scope, for each turbine, the monthly emissions limits were based on the highest monthly emissions, which take place in the summer. The annual emissions limits, however, limited VOC, PM_{10}, and SOx emissions to less than 4 TPY to meet the offset exemption requirement, yet allow higher utilization during the summer and lower utilization during the remainder of the year. For the new proposed project scope, the monthly emissions limits have been reduced, but the annual emission limits are now the monthly emissions limits multiplied by 12 months. With these new operating restrictions, the annual operating schedule for each turbine and the cooling tower will increase. This is the only change in emissions that would require re-modeling.

On December 16, 2008, the applicant submitted a second revised modeling package to evaluate the effect of the increased annual emissions for the criteria and toxic pollutants from the four turbines and the cooling tower. For Rule 1303 compliance, AERMOD was re-run for pollutants with annual averaging times (PM_{10}, NO_2, and SO_2) for the increased criteria pollutant emissions from each turbine. For Rule 1401 compliance, the HARP analyses were re-conducted to predict the new cancer risk and chronic non-cancer health index for the increased toxic emissions from each turbine and the cooling tower.

On December 19, 2008, the applicant submitted a copy of the transaction confirmation documentation for the purchase of the required emission reduction credits for VOC, PM_{10}, and SOx. Some of the emission reduction credits for PM_{10} were in the form of short term credits. Since the short term credits are valid for all years into perpetuity, they will be converted into emission reduction credits by the District as part of the change of title process.

On January 6, 2009, the applicant submitted a second revised Table 3-5—Durations and Criteria Pollutant Emissions for Commissioning of a Single CTG, along with an analysis regarding the reasons for the corrections. Since these changes do not result in an increase in modeled emissions, re-modeling is not required.

Annual Operating Schedule

The annual operating schedule per turbine is shown in the table below. The original application requested 1001.5 hours with 129 startups and shutdowns for normal operations for both the commissioning year and subsequent normal operating years, and an additional 156 hours for commissioning for the commissioning year only.

The revised Application requested 446 hours with 129 startups and shutdowns for normal operations for the commissioning year, 602 hours with 129 startups and shutdowns for normal operations for subsequent normal operating years, and an additional 156 hours for commissioning for the commissioning year only.

~~The normal operating hours were originally proposed to be 1001.5 hours , but were changed to 446 hours for the commissioning year and to 602 hours for subsequent years by the revised Application.~~The second revised Application requested, for a normal operating year, 90 hours of operation and 20 startups and shutdowns per month, which sets the maximum monthly emissions for VOC, SOx, and PM_{10} for which emission reduction credits will be provided. This translates into 1080 hours of operation and 240 startups and shutdowns per year. For the commissioning year, the second revised Application requested 156 hours for commissioning. Further, the monthly emissions for the commissioning period will not exceed the maximum monthly emissions for VOC, SOx, and PM_{10} during normal operation. Based on those criteria, the maximum number of normal operating hours will be less than 990 hours.

Table 2--Proposed Annual Operating Schedules Per Turbine

	1st Year--Commissioning	**Subsequent Normal OperatingYears**
Normal Operations, Not Including Start-ups and Shut-downs	1001.5[1] 446[2]~~5 ???~~ **< 990**[3] **hours**	1001.5[1] ~~602~~ 602[2] **1080**[3] hours
Start-up	129[1,2] **240**[3] starts (35 min/start)	129[1,2] **240**[3] starts (35 min/start)
Shutdown	129[1,2] **240**[3] shutdowns (10 min/shutdown)	129[1,2] **240**[3] shutdowns (10 min/shutdown)
Normal Operations, including Start-ups and Shut-downs	1098.25[1] 542.75[2] **<1170**[3] hours	1098.25[1] 698.75[2] **1260**[3] hours
Commissioning[~~*~~4]	**156**[1,2,3] hours	**0**[1,2,3] hours

[1] Original application, 12/26/07
[2] Revised application, 9/12/08
[3] Second revised application, 11/26/08
[~~*~~4] Commissioning of each turbine will occur during the first year of operation only.

Major Source/RECLAIM/Title V Facility

The CPP will be a major source under Regulation XIII because ~~the~~ facility NOx emissions for both the commissioning year and subsequent normal operating years will be greater than the 10 TPY major source threshold for NOx. The major source thresholds and the corresponding facility emissions are summarized in the table below.

The major source thresholds and the corresponding facility emissions are summarized in the table below.

Table 3—Major Source Applicability

Pollutant	Major Source Threshold (TPY)	Facility Emissions—Commissioning Yr / Normal Operating Year[1]
NOx	10	~~20.70~~ 20.56 tpy / ~~15.13~~ 14.98 tpy~~14.49 tpy / 8.86 tpy~~
CO	50	14.40 tpy / 12.08 tpy~~12.07 tpy / 6.97 tpy~~
VOC	10	3.10 tpy / 3.10 tpy~~1.55 tpy / 1.73 tpy~~
PM10	70	7.0 tpy / 7.18 tpy~~3.997 tpy / 3.997 tpy~~
SOx	100	0.80 tpy / 0.82 tpy~~0.55 tpy / 0.45 tpy~~

[1] The annual emissions for the commissioning year and the normal operating year are from Tables 26 and 27, respectively, below.

Formatted Table
Formatted: Not Strikethrough
Formatted: Font: Not Bold
Formatted: Not Superscript/ Subscript
Formatted: Not Superscript/ Subscript
Formatted: Font: Bold
Formatted: Not Strikethrough
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Not Superscript/ Subscript
Formatted: Not Superscript/ Subscript
Formatted: Font: Bold
Formatted: Font: Bold
Formatted: Not Superscript/ Subscript
Formatted: Font: Bold
Formatted: Font: Bold
Formatted: Not Strikethrough
Formatted: Not Strikethrough, Superscript
Formatted: Font: Not Bold
Formatted: Not Strikethrough, Superscript
Formatted: Superscript
Formatted: Not Strikethrough
Formatted: Not Strikethrough, Superscript
Formatted: Font: Not Bold
Formatted: Font: Bold
Formatted: Font: Not Bold, Superscript
Formatted: Font: Bold
Formatted: Font: Bold
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font: Not Bold

The CPP is both a RECLAIM and Title V facility. CPP has opted into RECLAIM at this time since the NOx emissions are anticipated to be over 4 TPY. CPP is Title V because it will be a major source, and because it will be subject to the federal Acid Rain provisions as it will operate CTGs rated at above 25 MW.

PROCESS DESCRIPTION

1. <u>A/N 476651, 476656, 476659, 476661—Compression Turbine Generators Nos. 1 - 4</u>
   The four new simple cycle CTGs will be natural gas-fired General Electric LM6000PC Sprint Combustion Turbine Generators, rated at 50.95 MW. The LM6000 is a 2-shaft engine derived from the CF6-80C2 jet aircraft engine. The CTGs are equipped with evaporative inlet air cooling and water injection into the combustion zone. The inlet combustion air will be cooled via a chiller cooling tower system to increase turbine performance during high ambient temperature conditions. The CTGs also will have water injection spray evaporative inter-cooling between the low-pressure and high-pressure compressor sections as well as to the inlet of the low-pressure compressor to increase turbine performance.

   The water injection into the combustor also will suppress flame temperature and reduce the 1-hour average NOx concentration to 25 ppmvd at 15% oxygen prior to entry into the SCR. As discussed below, the SCR catalyst with ammonia injection will further reduce the NOx emissions to 2.3 ppmv, 1-hour average, dry basis at 15% O2, which is lower than the 2.5 ppmv BACT limit.

   <u>General Discussion of LM6000</u>
   The LM6000 gas turbine is essentially an aeroderivative turbine, meaning that it is a dual-rotor, "direct drive" gas turbine, derived from the CF6-80C2, high-bypass, turbofan aircraft engine. The LM6000 takes advantage of its parent aircraft engine's low-pressure rotor operating speed of approximately 3,600 rpm. The low-pressure rotor is the driven-equipment driver, providing for direct coupling of the gas turbine low-pressure system to the load (the electrical generator). The LM6000 gas turbine consists of a five-stage low-pressure compressor; a 14-stage high-pressure compressor, which includes six variable-geometry stages; an annular combustor with 30 individually replaceable fuel nozzles; a two-stage, air-cooled high-pressure turbine; and a five-stage low-pressure turbine with an overall pressure ratio of approximately 29 to 1. The LM6000 gas turbine has two concentric rotor shafts: the low pressure (LP) compressor and turbine form the LP rotor, and the high pressure (HP) compressor and turbine form the HP rotor. The LM6000 is equipped with an evaporative cooling system that will be used for cooling the combustion air, and each unit will use the LP turbine to power the output shaft with a direct coupling to the 3600-rpm generator for 60 Hz power generation. The generator is a synchronous, two-pole cylindrical rotor generator with forced air-cooling.

For purposes of performance, and to assist prospective buyers, the International Organization for Standardization (ISO) has developed a set of conditions for rating and comparing gas turbine engines. ISO conditions are as follows:

Table 4--ISO Conditions

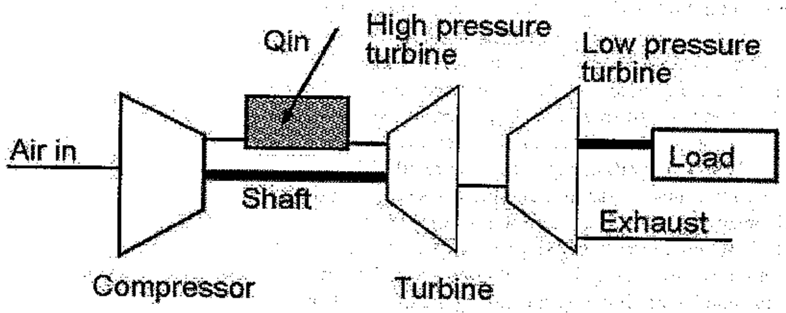
Parameters	Specifications
Ambient Temperature	15°C (59°F)
Barometric Pressure	14.70 psia (29.92 inches of Hg)
Relative Humidity	60%
Elevation	Sea level

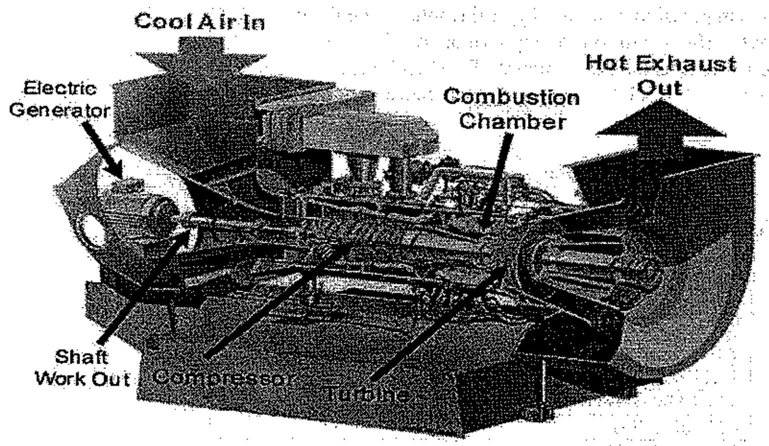
General Discussion of the Brayton Power Cycle

There are two power cycles that are generally used in the generation of electricity with turbines: the Rankine cycle (steam turbines), and the Brayton cycle (gas turbines). The Rankine cycle is used in most base load power plants which involve a combined cycle configuration as opposed to a simple cycle configuration. The Brayton cycle is the power cycle used for gas turbines, often used in peaking applications, as is the case with the CPP's proposed nominal 200 MW power plant. The Brayton cycle is an open cycle where ambient air is compressed to high temperature and pressure before it is fed to the combustion chamber. In the combustion chamber, the air-fuel mixture is ignited, dramatically increasing the temperature of the mixture. These hot gases are then expanded in a turbine, which can be coupled to an electric generator, as is the case with the CPP.

The LM6000 gas turbine operating on the Brayton Cycle configured with its dual concentric rotor shafts is shown in the generalized diagrams below, but the specific diagram configuration may vary slightly due to the use of the SPRINT technology.

Open Brayton Cycle with a Dual Rotor Shaft Arrangement





The above discussion focuses on the basics of the GE LM6000 gas turbine. However, the CPP is proposing to install a modified version of the LM6000. The four gas turbines that will be installed at the CPP are General Electric's LM6000PC Sprint model. The LM6000PC Sprint model is a more efficient engine due primarily to the incorporation of SPRINT technology. A discussion of the principles of SPRINT technology is provided below.

Discussion of SPRINT Technology

Unlike most gas turbines, the LM6000 is primarily controlled by the compressor discharge temperature in lieu of the turbine inlet temperature. Some of the compressor discharge air is then used to cool high-pressure turbine components. SPRINT, which stands for "spray intercooled" reduces compressor discharge temperature thereby allowing advancement of the throttle to significantly enhance power by 9 percent at ISO conditions and greater than 20 percent at 90°F (32 °C) ambient temperatures. The LM6000 Sprint system is composed of atomized water injection at both low-pressure compressor (LPC) and high-pressure compressor (HPC) inlet plenums. This is accomplished by using a high-pressure compressor, eighth-stage bleed air to feed two air manifolds, water-injection manifolds and sets of spray nozzles, where the water droplets are sufficiently atomized before injection at both LPC and HPC inlet plenums. Benefits of LM6000 Sprint generator-set include a generation capacity of up to 50 MW, development of full power within 10 minutes of start-up, multiple uses (peaking power, base loading, cycling), dual fuel capacity (distillate or natural gas), easy on-site maintenance, higher efficiency (~40%) than their heavy duty Frame counterparts (~32-34%). In summary, SPRINT technology uses spray intercooling to boost the power output of the basic LM6000 gas turbine by significantly increasing the mass airflow through cooling of the air during the compression process. Typical results range from approximately 9% more power output at ISO conditions to approximately 20% more power output on days when the ambient temperature is around 90°F. Therefore, as ambient temperature rises, the benefits of SPRINT technology become more significant.

Technical Specifications

The following table lists the technical specifications for the LM6000PC Sprint CTG.

Table 5—Combustion Turbine Generation Specifications[1]

Parameters	Specifications
Manufacturer	General Electric
Model	LM6000PC Sprint
Fuel Type	Public Utility Commission (PUC) Quality Natural Gas
Natural Gas Heating Value	1,012 BTU/scf
Gas Turbine Heat Input, HHV	479.2 MMBTU/hr at 46°F inlet with chiller
Maximum Fuel Consumption	475,000 SCFH[2]
Maximum Gas Turbine Exhaust Flow	215,000 DSCFM
Gas Turbine Exhaust Temperature	840 °F
Exhaust Moisture	12.5%
Maximum Gas Turbine Power Generation	50.95 MW gross
Net Plant Heat Rate, LHV	8842 BTU/kW-hr
Net Plant Heat Rate, HHV	9797 BTU/kW-hr
Net Plant Efficiency, LHV	38.6% LHV
Unabated NOx Emission Rate	25 ppmvd @ 15% O2

1 Values in this table are on a per-turbine basis.

2 Represents the maximum possible fuel consumption of the CTG, based on 479.2 MMBTU/hr heat input and 1,012 BTU/scf fuel heat content. However, the emission calculations will be based on a worst-case operating scenario as identified by the applicant, which may result in a lower fuel usage depending on the ambient temperature, the employment and rate of intercooling, water injection rates, and electrical load generated.

Electrical Interconnection and Process Water Supply

The net power generated by the CPP will be transmitted to COA's 69 kV transmission system though an onsite SF6 gas-insulated switchyard. A small amount of electrical power will be utilized onsite to power auxiliaries such as gas compressors, chillers, pumps, fans, and facility electrical loads including lighting and HVAC systems. Four new underground 69 kV circuits will leave the site. Two will proceed underneath and to the south side of East Miraloma Avenue approximately 100 feet to rise up and connect to the existing 69 kV overhead Vermont-Yorba lines via two new transition structures. The second two 69 kV underground circuits will proceed eastward approximately 4,000 feet in East Miraloma Avenue, turn south on Miller, then proceed approximately 3,000 feet to connect to the Dowling-Yorba 69 kV line at East La Palma Avenue.

The CPP will require process water primarily for the production of high purity demineralized and deionized water for CTG NOx injection, chilled water system cooling tower makeup, and miscellaneous plant domestic services. The process water will be recycled water supplied from the Orange County groundwater replenishment system (GWRS) via a new 2,185-foot-long, 14-inch pipeline utilizing a new offsite booster pump station. The water pipeline will run east of the site on the north side of East Miraloma Avenue for 1,850 feet to the new pumping station located north of the curb in the COA-owned easement of East Miraloma Avenue, then north 210 feet in new easement from the Orange County Water District (OCWD), then 125 feet easterly in new easement to the GWRS line on the western side of the Carbon Canyon Diversion Channel. There, it will connect to the 60-inch-diameter GWRS recycled water line at an existing 36-inch stub up. Water filtration and demineralization equipment will be used to make high-quality deionized water to operate the CTG water injection systems, CTG water wash, and CTG Sprint systems.

2. A/N 476654, 476657, 476660, 476663—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 1-4

Each CTG will be equipped with a selective catalytic reduction/CO oxidation catalyst system.

- *CO Oxidation Catalyst*

  The CO oxidation catalyst, located between the CTG and the SCR, will be used to control CO and VOC emissions. The catalyst will reduce CO emissions to 4 ppmv and the VOC to 2 ppmv, both 1-hour averages, dry basis at 15% O_2.

  The following table lists the technical specifications for the CO oxidation catalyst.

Table 6 - CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	Englehard/BASF
Model	Camet, washcoat on ss foil substrate
Catalyst Type	Pt on Al

Catalyst Life	10,000 hours or 5 years
Space Velocity	210,000 hr^{-1}
Catalyst Volume	110 ft^3
CO removal efficiency	75% or greater
CO at stack outlet	4.0 ppmvd at 15% O_2
VOC at stack outlet	2.0 ppmvd at 15% O_2
Minimum Operating Temperature	500°F
Exhaust gas velocity	11.7 ft/s

- *Selective Catalytic Reduction*
  The SCR catalyst will use ammonia injection in the presence of the catalyst to further reduce the NOx concentration in the exhaust gases. Diluted ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst. The resulting reaction will reduce NOx to elemental nitrogen and water, resulting in NOx concentrations in the exhaust gas at no greater than 2.3 ppmv at 15% O2 on a 1-hour average. The ammonia slip will be limited to 5 ppmvd at 15% O2. Each SCR will be vented through a dedicated stack, which is 11.7 ft diameter and 86 ft high.

  The ammonia injection is initiated after the thermocouple at the outlet of the NOx catalyst has a reading of 540°F or higher. The minimum temperature is required to protect the catalyst face from ammonia salt formation and deposition on a cold catalyst. (See condition D12.2.) The catalyst is designed for a temperature range of the specified operating scenarios, which range from 665°F at cold ambient/turndown up to a controlled temperature of 850°F (± 20°F). The catalyst is designed for continuous operation up to 870°F, with no more than 500 hours between 870°F and 932°F, and no more than 4 hours between 932°F and 1022°F. Prolonged operation for hours greater than indicated will reduce the catalyst's life expectancy and performance capability. (See condition D12.3.) The maximum expected pressure drop across the catalyst, based on the specified operating cases, is 6 inches w.c. (See condition D12.4.) The specified operating cases allow for a variation of ammonia flow rate from 52.8 lb/hr (6.83 gal/hr based on specific gravity of 0.9277) up to 124 lb/hr (16.03 gal/hr), based on 19% aqueous ammonia. (See condition D12.2.)

  The following table lists the technical specifications for the SCR.

Table 7 - Selective Catalytic Reduction Specifications

Catalyst Properties	Specifications
Manufacturer	Cormetech
Catalyst Description	Homogeneous extruded honeycomb with Ti-V-W
Catalyst Model No.	CMHT-21
Catalyst Volume	1,012 ft^3

Reactor Dimensions	18 ft wide x 25 ft tall x 2.5 ft deep
Guaranteed Life	Earliest of 10,000 hrs from first gas in or 66 months from contracted delivery.
Space Velocity	720,000 hr^{-1}
Area Velocity	39,600
Ammonia Injection Rate	52.8 -123.8 lb/hr
Ammonia Slip	5 ppm, 1 hour average at 15% O2
NOx removal efficiency	>90%
NOx at stack outlet	2.3 ppmv at 15% O_2
Exhaust Temperature	740-840°F
Pressure Drop	6 inches water column

- *Performance and Catalyst Life Warranties*
  - *Performance Warranty*

    The applicant has contracted with General Electric to provide four power blocks, which each are comprised of a LM6000PC Sprint CTG, associated control equipment, and CEM. GE provided a guarantee, dated 6/26/08, for controlled emissions levels, which are shown in the table below.

Table 8 --Warranted Emissions for Control Systems

Pollutants	Warranted Emissions
NOx	2.3 ppmvd at 15% O_2
CO	6 ppmvd at 15% O_2
VOC	2 ppmvd at 15% O_2
PM_{10}	3 lb/hr
NH_3	5 ppmvd at 15% O_2, dry basis

CO--The warranted emission rate of 6 ppmv is the same as the current BACT/LAER limit. The District, however, has determined that 4 ppmvd at 15% O2 is now sufficiently well demonstrated to be achieved in practice for simple cycle gas turbines. The applicant has confirmed with GE that the proposed CTGs will be able to meet the 4 ppmvd, but GE will not be providing a performance guarantee for that level. The issuance of the P/Cs will be based on 4 ppmvd.

VOC, and NH_3--The warranted emission rates are the same as the BACT/LAER limits.

NOx— The warranted emission rate of 2.3 ppmvd is lower than the 2.5 ppmvd BACT/LAER limit. The 2.3 ppmvd corresponds to the limit of 0.080 lb/MW-hr, corrected to ISO conditions, which was required by 1309.1(b)(5)(A)(iii). As explained above, Rule 1309.1 is no longer

Formatted: ~~Tab stops: 5.5", Left + Not at 3" + 6"~~

conditions limit emissions for an hour that includes a full startup, a 5 minute purge period, and the first 20 minutes of a restart.

During shutdowns, it is not technically feasible for the turbines to meet BACT limits during the entire shutdown because both water injection into the turbines and ammonia injection into the SCR reactor have ceased operation. (See Table 14A above for the shutdown emissions profile.) The SCR and CO catalysts, however, are still above ambient temperatures and continue to operate for a portion of the shutdown. To limit shutdown emissions, condition nos. A99.1, A99.2, and A99.3 limit each shutdown to 10 minutes and limit the number of shutdowns to ~~129~~240 per year. These conditions also set emissions limits for an hour which includes a shutdown.

- *~~CEQA~~ Top-Down BACT Analysis*

  The SCAQMD Best Available Control Technology Guidelines do not require a top-down BACT analysis for non-major polluting facilities. ~~CEQA, however,~~ However, major polluting facilities are subject to Lowest Achievable Emission Rate (LAER), which requires a top-down ~~BACT~~ analysis to identify the most stringent emission limitation or control technique that meets the definition of BACT. ~~Although the CEC is the lead agency for the CEQA analysis, the District has primary responsibility for BACT determination. Thus, the analysis will be performed by the District in this section.~~

  The following top-down BACT analysis is performed pursuant to the guidance provided in EPA's October 1990 Draft New Source Review Workshop Manual. ~~The guidance was for PSD sources, but is applicable to this CEQA analysis as well.~~

  The five steps of the process are:

  1. Identify all control technologies;
  2. Eliminate technically infeasible options;
  3. Rank remaining control technologies by control effectiveness;
  4. Evaluate most effective controls and document results; and
  5. Select BACT.

  Step One—Identify all control technologies.

  The three basic means of controlling NOx emissions from combustion turbines are wet combustion controls, dry combustion controls, and post-combustion controls. Wet and dry combustion controls act to reduce the formation of NOx during the combustion process, while post-combustion control remove NOx from the exhaust stream.

  The following potential control technologies were identified.

- Wet Combustion Controls
  Water/Steam Injection

- Dry Combustion Controls
  Dry low-NOx combustor design
  Catalytic combustors (e.g., XONON)

- Post-Combustion Controls
  Selective catalytic reduction (SCR)
  EMx system (formerly SCONOx offered by Goal Line Environmental)

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Step Two—Eliminate technically infeasible options.
The technical feasibility of the control options identified in step one is evaluated with respect to the source-specific factors.

Water/Steam Injection
Water or steam injection directly into the turbine combustor lowers the flame temperature in the combustor and thereby reduces thermal NOx formation. (Thermal NOx is created by the reaction at higher temperatures of the nitrogen and oxygen in the air.) Water injection typically reduces NOx to 25-42 ppmvd at 15% O_2, and steam injection reduces NOx to 15-25 ppmvd at 15% O_2. These wet injection techniques are among the most common NOx control techniques for combustion turbines. Thus, this technology is *technically feasible.*

Formatted: Font: Italic, No underline

Dry low-NOx combustor design
Dry low-NOx (DLN) combustors use lean, premixed combustion to keep peak combustion temperature low, thus reducing the formation of thermal NOx. The combustor is the space inside the gas turbine where fuel and compressed air are burned. The DLN minimize combustion temperatures by providing a lean premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The resulting lower temperatures reduce NOx formation. Combustors typically reduce NOx to 9-25 ppmvd at 15% O_2. Several turbine vendors have developed the DLN technology for their engines, including the GE LM6000PC Sprint turbine proposed for this project. Thus, this technology is *technically feasible.*

Formatted: Font: Italic, No underline

(DLN combustors, however, are not compatible with wet combustion controls. Either DLN or wet combustion controls may be used, but not both.)

Catalytic combustors (e.g., XONON)
Catalytic combustors use a catalyst integrated into the gas turbine combustor to limit temperature below the temperature where NOx is formed. Fuel is partially

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

combusted in the catalyst followed by compete combustion downstream in the burnout zone. Partial combustion in the catalyst produces no NOx, because the catalyst limits the temperature in the combustor and helps stave off the production of NOx. This technology has been commercially demonstrated under the trade name XONON. Each XONON combustor is customized to the particular turbine model and application and is defined through a collaborative effort with the turbine original equipment manufacturer to integrate the hardware into the design. General Electric and Kawasaki are the only turbine vendors to indicate the commercial availability of catalytic combustion systems at the present time, but only on small, less than 10 MW, turbines. Since the proposed turbines are 50 MW units, this technology is ***not technically feasible.***

Formatted: Font: Italic, No underline

Selective catalytic reduction (SCR)

Equipment and Process Description

SCR is a post-combustion technique that controls both thermal and fuel NOx emissions. The SCR process involves the injection of ammonia into the turbine exhaust gas streams by means of an ammonia injection grid upstream of the catalyst. The ammonia is a reducing agent that reacts with NOx and oxygen in the presence of a catalyst to form water vapor and nitrogen. The catalyst is not regenerated and requires periodic replacement. The proposed SCR is guaranteed to reduce NOx from 25 ppmvd to 2.3 ppmvd at 15% O_2, except during startup and shutdown events. A typical SCR system is comprised of a SCR reactor with catalyst, ammonia storage tank, and vaporization and injection equipment for the ammonia, a booster fan for the turbine exhaust gas, and instrumentation and control equipment.

Excess ammonia is required for efficient conversion of NOx to nitrogen, because of the imperfect distribution of the ammonia in the catalyst. Thus, a small amount of ammonia remains unreacted in the exhaust stream and is referred to as "ammonia slip." Ammonia slip increases as the catalyst ages, necessitating the use of increasing amounts of ammonia injection to maintain NOx concentrations at or below the design concentration. The ammonia slip from the proposed SCR is guaranteed to meet the BACT limit of 5.0 ppmvd @ 15% O_2, 1-hr average. The slip from a new catalyst is typically lower than the BACT limit. Ammonia is a precursor to PM_{10} emissions.

(A carbon monoxide (CO) oxidation catalyst for CO and VOC control is typically used in conjunction with the SCR. The CO oxidation catalyst oxidizes the CO and a portion of the VOC in the exhaust gas into carbon dioxide. The proposed CO oxidation catalyst is guaranteed to reduce the CO from 30 ppmvd to 6 ppmvd (4 ppmvd actual) and the VOC from 3 ppmvd to 2 ppmvd, all at 15% O_2, except during start-up and shut-down events.)

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Technical Feasibility Analysis

SCR systems have been widely used in simple-cycle natural gas turbine applications for many years, almost exclusively in conjunction with other wet or dry NOx combustion controls. Further, SCR systems are commercially available from several vendors. Thus, this technology is *technically feasible.*

Formatted: Font: Italic, No underline

EMx system (formerly SCONOx offered by Goal Line Environmental)

Equipment and Process Description

The EMx system is a proprietary catalytic oxidation and absorption technology available through EmeraChem LLC (formerly Goal Line Environmental Technologies) that uses a single catalyst, EMx catalyst, for the removal of CO, VOC, PM, and NOx. A secondary catalyst, ESx catalyst, is located upstream of the EMx catalyst to remove the sulfur dioxide in the turbine exhaust stream to prevent masking of the EMx catalyst. A typical EMx system is comprised of a catalyst rack and reactor housing with EMx and ESx catalysts, catalyst module inlet and outlet dampers, regeneration gas production and distribution system, regeneration gas condensing (or steam recovery) system (optional), SOx scrubbing system (optional), catalyst removal system, and instrumentation and control equipment.

EmeraChem submitted a proposal for an EMx system for the CPP project to the applicant. The applicant subsequently submitted to the District the ECM Technology White Paper, PB Power, July 2008. (See Appendix I in revised Application.) The proposed EMx system is guaranteed to reduce NOx from 25 ppmvd to 2.32 ppmvd at 15% O_2, the CO from 30 ppmvd to 6 ppmvd, the VOC from 3 ppmvd to < 1 ppmvd, and the PM from 3 lbs/hr to 2.1 lbs/hr, all at 15% O_2, except during startup and shutdown events. Also the EmeraChem's EMx system does not use any ammonia (NH_3) so there will be no ammonia slip emissions from the stack.

Formatted: Subscript

The EMx catalyst system removes CO, VOC, PM (new claim), and NOx with the same catalyst arranged in a module consisting of a number of isolatable chambers (10 for the CPP). As the turbine exhaust gas passes through the catalyst modules, the EMx catalyst oxidizes CO into CO_2, and VOC into CO_2 and water, which are vented to the atmosphere. With the oxidation of condensable organic compounds into CO_2 and water, and the reduction of SO_3 to SO_2 by the ESx catalyst (see below for discussion), two precursors of PM are reduced thereby reducing the formation of PM. As the NOx passes through the catalyst modules, NOx is oxidized to NO_2. The NO_2 is chemically absorbed onto the catalytic surface using a potassium carbonate (K_2CO_3) absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto and remain onto the catalyst surface until regeneration occurs.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

When all the potassium carbonate absorber coating has been converted to potassium nitrite and nitrate compounds, NOx can no longer be absorbed and the catalyst must be regenerated. Two out of the proposed ten catalyst chambers are designed to be in the regeneration cycle at any given time. Each chamber is required to be regenerated 5 to 7 minutes, every 20 to 28 minutes. Regeneration is achieved by isolating two chambers with dampers and injecting into the downstream end of the chambers a reducing atmospheric carrier, such as steam, containing a small amount of hydrogen gas. This regeneration gas flows upstream through the EMx catalyst chambers over the catalyst surface. The hydrogen in the regeneration gas reacts with the potassium nitrites and nitrates on the catalyst surface to form water, nitrogen and potassium hydroxide. The water and nitrogen are exhausted out the stack. The carbon dioxide in the turbine exhaust reacts with the potassium hydroxide to form potassium carbonate, which re-deposits onto the catalyst surface as the coating. No net gain or net loss of potassium carbonate occurs after the oxidation/absorption and regeneration cycle. The regeneration stream exits the upstream end of the EMx chambers, then continues through the ESx catalyst (see below), allowing the two catalysts to be regenerated simultaneously. After exiting the ESx catalyst, the regeneration gas is vented into the turbine exhaust duct downstream of the EMx system where it is vented to the atmosphere or sent to a condensate recovery system for steam and water recovery.

The small amount of sulfur dioxide in the turbine exhaust gas, if left untreated, will form potassium sulfate and mask the EMx catalyst and require removal of the catalyst for chemical washing to regain effectiveness. Consequently, a secondary catalyst system, ESx, is installed upstream of the EMx catalyst to reduce the SOx reaching the EMx catalyst. As the turbine exhaust gas passes through the ESx catalyst, the SO_2 is oxidized to SO_3, which is absorbed on the catalyst surface. Regeneration is achieved by passing the regeneration gas through the EMx catalyst (see above) and then the ESx catalyst where the SO_2 is released and exhausts with the regeneration gas. The ESx catalyst and regeneration process remove the SO_2 from the exhaust stream but do not destroy the SO_2.

Because the ESx catalyst is not 100 percent effective in the capture of sulfur compounds, the EMx catalyst will require periodic "washing" to revitalize the catalyst by removing sulfur and other contaminants which fouls the catalyst over time. The washing process uses de-ionized water and potassium carbonate solution to rejuvenate the catalyst to its original level of activity and prevent the need for frequent replacement. The process includes removal of the EMX catalyst, washing of the catalyst on-site, and re-installation of the washed catalyst. The projection is that removal, washing, and re-installation of the EMx catalyst will occur once or twice a year for the CPP. Further, the installation of a

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

70-foot high catalyst service elevator will be needed to facilitate the catalyst removal and replacement operations.

The regeneration gas used to remove the absorbed NOx and SOx is composed of hydrogen and steam. Consequently, additional equipment is required to generate the hydrogen and steam onsite. One, hydrogen generating equipment is required. EmeraChem has proposed two H_2Gen HGM 10000 units, which use electrical heaters to generate steam by reforming natural gas (methane) into H_2 and CO_2. In a warm-up cycle, this unit is at design output within two hours. A pressurized hydrogen storage tank would be required to provide the hydrogen supply to the regeneration system until full production can be reached. Two, steam generating equipment is required because a simple cycle gas turbine peaking unit does not produce steam. EmeraChem has proposed a natural gas fired steam boiler for the CPP project. The boiler operation will produce an additional amount of NOx, CO, VOC, and PM_{10} emissions as a result of the combustion of the natural gas. Also, from a cold plant startup condition, it will take time for the steam boiler to heat up and produce the necessary process steam which in turn is expected to lengthen the EMx system startup time. As the EMx system requires that each chamber be regenerated every 20 to 28 minutes, it appears that regeneration of at least two chambers would be required during the first hour of operation. Further, the California ISO is not required to provide any lead time prior to dispatching the CPP in emergency situations, although a minimum of 45-minute lead time is provided in all other situations. Although there is no startup time operating experience with the EMx system in simple cycle operation, it is expected that the EMx system could reasonable reach stack compliance in approximately one hour due to the potential lack of lead time provided by the California ISO and the complexity of the steam generation, hydrogen generation, and associated control systems.

The proposed EMx catalyst is designed to perform in the operating temperature range of 600 to 700 °F. Since the exhaust gas from the LM6000 PC Sprint will vary between 710 and 860 °F, large tempering air fans will be required to blow cold outside air into the exhaust stream (or adding an air to air exchanger to cool the exhaust stream to the required temperature) before entry into the catalyst. The tempering air volume that will be needed is approximately 30% of the total volume of the exhaust gases. This large quantity of tempering air will need to be thoroughly mixed with the exhaust gases in a relatively short distance to provide a homogenous gas mixture to the catalyst system for proper emission control.

As the CPP is a peaking power plant, it is expected that the CPP will only operate during the hottest part of the day and normally be off line during nighttime hours. Whether the EMx system will be able to withstand the frequent thermal cycling

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

from maximum to minimum temperature imposed on the structure and catalyst is unknown.

<u>Technical Feasibility Analysis</u>
If the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and technically feasible. The EMx system is currently installed on turbines at five facilities as of June 2008. The information presented in the table below is from "High Performance EMx™ Emission Control Technology for Fine Particles, NOx, CO and VOCs from Gas Turbines and Stationary IC Engines," June 2008, by Steven DeCicco and Thomas Girdlestone, EmeraChem Power, Knoxville, TN.

Table 33 –Current EMx Installations

Turbine & Fuel	Facility	Location/ Start-up Date	Operating Temperature °F	Permit Limit, NOx @ 15% O_2	Type of Facility
5 MW Solar Taurus 60 dual-fuel turbine	Wyeth BioPharma cogeneration facility Unit #2	Andover, MA/ September 2003	625 °F	2.5 ppmvd on gas 15 ppmvd on oil	Cogeneration
5 MW Solar Taurus 60 dual-fuel turbine	Montefiore Medical Center cogeneration facility	Bronx, NY/ June 2002	525 °F	2.5 ppmvd on gas 15 ppmvd on oil	Cogeneration
45 MW Alstom GTX100 gas turbine (Second identical turbine under construction)	Redding Electric municipal plant	Redding, CA/ June 2002	525 °F	2.0 ppmvd on gas	Combined Cycle
Two 15 MW Solar Titan 130 gas turbines	University of California cogeneration facility	San Diego, CA/ July 2001	425 °F	2.5 ppmvd on gas	Cogeneration
5 MW Solar Taurus 60 dual-fuel turbine	Wyeth BioPharma cogeneration facility Unit #1	Andover, MA/ 1999	625 °F	2.5 ppmvd on gas 15 ppmvd on oil	Cogeneration

32 MW GE LM2500 gas turbine	Sunlaw Federal cogeneration facility	Vernon, CA/ 1996	N/A	N/A	Cogeneration

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

The proposed CPP turbines are 50 MW simple cycle turbines. The current EMx installations are for cogeneration or combined cycle turbines, with the sizes ranging from 5 MW to 43 MW. A simple cycle turbine produces electricity without recovery of exhaust heat, and is typically used by electric utilities for generation of electricity during emergencies or during peak demand periods. A cogeneration turbine consists of a simple cycle turbine with a heat recovery steam generator (HRSG) that produces steam/hot water to deliver to other thermal processes at the site. A combined cycle gas turbine drives an electrical generator and the steam from the HRSG dries a steam turbine which also drives an electric generator. Thus, the control technology has ***not*** been installed and operated successfully on the type of source under review.

Formatted: Font: Italic, No underline

An undemonstrated technology is technically feasible, however, if it is available and applicable. The technology is available because EmeraChem has submitted a proposal for the CPP. A commercially available control option will be presumed applicable if it has been or is soon to be deployed on the same or a similar source type. There are currently no simple cycle power plants operating with an EMx system, nor are there any simple cycle power plant projects that have ordered an EMx system. Absent such a showing, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source type to which the technology has been based previously. For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which a the process technical had been applied previously.

Although cogeneration turbines, combined cycle turbines, and simple cycle turbines are all turbines, there are major differences in the operating parameters of the cogeneration and combined cycle turbines on which the EMx technology have been installed versus the simple cycle turbines proposed for the CPP. First, the cogeneration and combined cycle turbines produce steam, whereas the simple cycle turbines do not. Thus, a simple cycle turbine facility will be required to install a boiler or other steam producing equipment to produce the steam required for the regeneration gas. As explained above, the addition of the boiler may prolong a startup from the 35 minutes projected for the current project to one hour with the boiler. Second, the exhaust temperature from a simple cycle turbine is higher than from a cogeneration or combined cycle turbine. Therefore, large tempering fans will be required to blow cold air into the exhaust stream before entry into the catalyst, with the tempering air volume estimated to be approximately 30% of the total volume of the exhaust gases. It has not been demonstrated whether the large quantity of tempering air will be sufficiently mixed to produce the homogenous mixture required for the catalyst to operate properly. Third, simple cycle turbines require more rapid startups and shutdowns, and more frequent load changes than cogeneration or combined cycle turbines. It has not been demonstrated whether the EMx system will be able to withstand the frequent thermal cycling. Fourth, the EMx technology has not been installed on turbines rated at greater than 45 MW. It has not been demonstrated that the EMx technology can be successfully scaled up to the 50 MW rating of the proposed CTGs for the CPP. Therefore, the conclusion is that the EMx technology is ***not*** technically feasible.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted: Font: Italic, No underline

Step Three—Rank remaining control technologies by control effectiveness.
The remaining technically feasible control technologies are ranked by NOx control effectiveness in the table below.

Table 34—NOx Control Technology Alternatives

NOx Control Technology	NOx Emissions at 15% O_2	Environmental Impact	Energy Impacts
Water Injection	25-42 ppm	Increased CO/VOC	Decreased Efficiency
Steam Injection	15-25 ppm	Increased CO/VOC	Increased Efficiency
Dry Low-NOx Combustors	9-25 ppm	Reduced CO/VOC	Increased Efficiency
Selective Catalytic Reduction	> 90% reduction 1-2.5 ppm	Ammonia slip	Decreased Efficiency

Step Four—Evaluate most effective controls and document results.
Water injection with SCR, steam injection with SCR, and dry low-NOx combustors with SCR all result in NOx emissions of 1-2.5 ppm.

Step Five—Select BACT.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Because the controlled NOx emission rate will be 1-2.5 ppm with water injection with SCR, steam injection with SCR, or dry low-NOx combustors with SCR, these technologies are all considered BACT.

3. A/N 476665–Ammonia Storage Tank
The tank will be a pressure vessel with a pressure relief valve set at 25 psig to control breathing losses. The filling losses will be controlled by a vapor return line to the delivery vehicle. Use of a pressure vessel for storage and a vapor return line for transfer is considered BACT for an ammonia storage tank.

4. A/N 476666—Emergency ICE (Black Start Engine)
The BACT Guidelines for Non-Major Polluting Facilities sets forth under Equipment or Process: I.C. Engine, Stationary, Emergency, dated 10/3/08 Rev. 4, for Subcategory: Compression-Ignition, Other, the emissions limits for NOx + NMHC, SOx, CO, and PM. The guidelines also restrict operation to 50 hours for maintenance and testing and specify the parameters for allowed operation beyond the 50 hours in footnote 3. This engine is subject to Tier 2 standards.

As shown below, the emission levels comply with the Tier 2 standards.

Table 35—Engine BACT Requirements and Manufacturer's Specifications

	NOx + NMHC	SOx	CO	PM
BACT Limits ≥ 750 HP	Tier 2 4.8 g/bhp-hr	Diesel fuel with a sulfur content no greater than 0.0015% by wt. (Rule 431.2)	Tier 2 2.6 g/bhp-hr	Compliance with Rule 1470: ≤ 0.15 g/bhp-hr Tier 2 0.15 g/bhp-hr
AQMD Certified Emissions Levels	4.1 g/bhp-hr (0.02 g/bhp-hr ROG + 4.08 g/bhp-hr NOx)	Meets Rule 431.2.	0.75 g/bhp-hr	0.06 g/bhp-hr

The restriction of operation to 50 hours for maintenance and testing is implemented by condition no. C1.1, and the parameters for allowed operation beyond the 50 hours are set forth in condition no. E193.2.

Further, LAER requires a diesel particulate filter (DPF) for the engine. The most recent BACT determination requiring a DPF that is shown in the District's BACT database is for Claremont Manor. Although not listed in the BACT database, Mountain View Power has a diesel black start ICE (2155 bhp) with a filter already in operation. Thus, a DPF is considered achieved in practice. For example, the new CPV Sentinel power plant and the City of Riverside power plant expansion each are proposing a DPF.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

The engine will be controlled by a CleanAIR Systems PERMIT™ DPF. This DPF system is verified by CARB under Executive Order DE-05-002-01 to reduce emissions of diesel particulate matter consistent with a Level 3 device (greater than or equal to 85 percent reduction), with the use of low sulfur diesel with 15 ppm or lower sulfur content.

5. A/N 481185—Oil Water Separator
   BACT is not applicable because the VOC emissions are less than 1 lb/day.

- *Rule 1303(b)(1)–Modeling*
- *Rule 2005(b)(1)(B)-Modeling*

Rule 1303(b)(1) requires air dispersion modeling to substantiate that a new permit unit which results in a net emission increase of any nonattainment air contaminant at a facility will not cause a violation, or make significantly worse an existing violation according to Table A-2 of the rule, of any state or national ambient air quality standards at any receptor location in the District. The standards are for NO_2 (non-RECLAIM facility), CO, PM_{10}, and sulfate. Rule 2005(b)(1)(B) requires modeling for NO_2 for RECLAIM facilities.

Compliance determination is different for attainment and nonattainment pollutants. For the attainment pollutants, NO_2, CO, and SO_2, the project impact plus the background concentration should not exceed the most stringent air quality standard. For the non-attainment pollutant, $PM_{10,}$ the project impact should not exceed the significant change in air quality concentration.

The standards in Rule 1303 Table A-2, as amended December 6, 2005, are outdated. The modeling results provided by the applicant, see below, uses the current ambient air quality standards.

The applicant conducted modeling using the EPA AERMOD dispersion model (Version 07026). The surface meteorological data were obtained for the John Wayne Airport meteorological station in Santa Ana for calendar years 2002 through 2006. The upper air meteorological data were obtained from the Miramar Naval Air Station near San Diego for the same period. The background concentrations are the maximum recorded concentration at Anaheim-Pampas Lane station, Costa Mesa-Mesa Verde Drive station, La Habra station, Mission Viejo station, or Pico Rivera station for 2004-2006.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

1. A/N 476651, 476656, 476659, 476661—Combustion Gas Turbines Nos. 1 - 4
2. A/N 476654, 476657, 476660, 476663—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 1 - 4

The applicant provided a revised modeling analysis for air quality modeling and health risk assessment on September 12, 2008, for an individual turbine for normal operations, startup, and commissioning. Modeling is not required for the shutdown mode, because startup emissions are higher than shutdown emissions. The modeling was performed for NOx, CO, SO_x, and PM_{10}, even though CO is in attainment and thus exempt from modeling requirements.

Further, the modeling included the black start engine and the cooling tower. The black start engine is exempt from air quality modeling due to Rule 1304(a)(4) and Rule 2005(k)(5), and the cooling tower is exempt from air quality modeling because it is exempt from permitting. However, the CEC requires air quality modeling for the engine and cooling tower to demonstrate CEQA compliance.

The revised modeling analysis was supplemented with a second revised modeling analysis for air quality modeling and health risk assessment submitted on December 16, 2008, for the increased annual emissions for the turbines and cooling tower.

The District modeling staff reviewed the applicant's two modeling analyses for ~~both~~ air quality modeling and health risk assessment. The review concluded the air quality modeling results ~~is~~are acceptable. (See memorand~~um~~a from Sr. Manager Naveen Berry to Sr. Manager Mike Mills, dated 10/16/08 and 1/13/09.)

The table below presents the reasonable worst-case project emissions scenarios for each combination of pollutant and averaging times corresponding to an air quality standard or significance limit.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Table 36
Criteria Pollutant Sources and Emission Totals for the Worst-Case Project Emissions Scenarios for All Averaging Times

Averaging Time	Operating Equipment	Emissions in Pounds – Entire Period			
		Pollutant	Four CTGs	Black Start Engine	4-cell Chiller Cooling Tower
1-hour	NO_x and CO: One 35-minute startup (all CTGs) with remainder of period at normal operations (100% load, 59°F).	NO_x	57.08 (14.27 lb/hr[1])	12.06	-
	SO_2: 100% load operation (4 CTGs) at 59°F ambient temperature.	CO	25.20 (6.3 lb/hr[2])	5.79	-
	All: includes one 38-minute test of black start engine.[5]	SO_2	5.4[3]	0.006	-
3-hour	SO_2: Continuous 100% load operation (all CTGs) at 59°F ambient temperature, plus one 38-minute test of black start engine.	SO_2	16.28[3]	0.006	-
8-hour	CO: One 35-minute startup, turbine trip with no operation for 5 minutes followed by a 32-minute restart; one shutdown and the remainder of the period at normal operations (100% load, 59°F) (all CTGs), plus one 38-minute test of black start engine.	CO	143.74	5.79	-
24-hour	PM_{10}: Continuous full-load (all CTGs) at 59°F ambient temperature plus the emissions from 4-cell chiller cooling tower.	PM_{10}	268.0	0.33	0.86
	SO_2: Continuous full-load (all CTGs) at 59°F ambient temperature. All: includes one 38-minute test of black start engine.	SO_2	130.56[3]	0.006	-
Annual	All: each CTGs operates at full load for ~~602~~1080 hours at 49°F (cooler on), ~~129~~240 startups and shutdowns), plus operation black start engine (200 hours per year).	NO_x	~~15,146~~27,840	2,412	-
	PM_{10}: include the emissions from 4-cell	PM_{10}	~~7,983~~14,352	10.8	180.14

	chiller cooling tower for all hours of CTG operation.	SO_2	~~899.0~~1632[4]	~~1.14~~2.46	

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

1 Condition no. A99.1 limits the maximum hourly NOx startup emissions to 14.27 lb/hr.
2 Condition no. A99.2 limits the maximum hour CO startup emissions to 6.3 lb/hr.
3 1-hr, 3-hr, and 8-hr SO_2 are based on natural gas fuel sulfur content of 1.0 gr/100 scf.
4 Annual SO_2 is based on natural gas sulfur content of 0.25 gr/100 scf, which also is used for emission calculation.
5 Although the black start engine is exempt from air quality modeling due to Rule 1304(a)(4) and Rule 2005(k)(5), modeling is required ~~for~~by the CEC for CEQA compliance. Although the BACT limit of 4.8 g/bhp-hr, or 12.06 lb/hr, is used to calculate the required number of RTCs, the certified emission rate of 4.08 g/bhp-hr, or 10.27 lb/hr, is used for the modeling pursuant to CEC guidance. **The engine may be tested at the 10.27 lb/hr rate for up to 38 minutes in any hour without causing an exceedances of the California one-hour NO_2 standard. Consequently, condition no. C1.1 limits the duration of maintenance tests for this engine to 38 minutes ~~per test~~in any one hour.**

Formatted: Font: Bold

The modeling results for normal operation, startup, and commissioning for a single turbine are summarized below in Tables 37, 38, and 39.

Normal Operation

For NO_2, CO, and SO_2, the table below shows, during normal operation, the highest predicted concentration for any CTG plus the background concentration does not exceed the most stringent air quality standard. For PM_{10}, the highest predicted concentration for any CTG does not exceed the significant change in air quality concentration.

Table 37--Model Results – Normal Operation-Individual Turbine

Pollutant	Averaging Period	Maximum Predicted Concentration (µg/m³)				Background Concentration (µg/m³)[1]	Highest Predicted CTG Concentration Plus Background Concentration (µg/m³)	Most Stringent Air Quality Standard (µg/m³)	Significant Change in Air Quality Concentration (µg/m³)	Comply (Yes /No)
		CTG 1	CTG 2	CTG 3	CTG 4					
NO_2	1-hour	1.87	1.87	1.86	1.88	229.1	230.98	338		Yes
	Annual	0.016~~0~~ ~~.01~~	0.016~~0~~ ~~.01~~	0.016~~0~~ ~~.01~~	0.016~~0.~~ ~~01~~	46.7	46.71	56		Yes
CO	1-hour	1.99	1.99	1.98	2.00	8,510	8,512	23,000		Yes
	8-hour	1.41	1.42	1.42	1.41	4,544	4545.42	10,000		Yes
SO_2	1-hour	0.64	0.64	0.63	0.64	81.2	81.84	655		Yes
	3-hour	0.48	0.49	0.49	0.49	52	52.49	1,300		Yes
	24-hour	0.21	0.21	0.21	0.21	21	21.21	105		Yes
	Annual	0.001	0.001	0.001	0.001	5.3	5.3001	80		Yes
PM_{10}	24-hour	0.47	0.47	0.47	0.47				2.5	Yes
	Annual	0.009~~0~~	0.009~~0~~	0.009~~0~~	0.009~~0.~~				1	Yes

		~~.005~~	~~.005~~	~~.005~~	~~005~~				
PM2.5	24-hour	0.47	0.47	0.47	0.47			n/a	Yes
	Annual	0.0090 ~~.005~~	0.0090 ~~.005~~	0.0090 ~~.005~~	0.0090 ~~.005~~			n/a	Yes

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Startup

For NO_2 and CO, the table below shows, during startups, the highest predicted concentration for any CTG plus the background concentration does not exceed the most stringent air quality standard.

Table 38--Model Results – Startup-Individual Turbine

Pollu-tant	Avera-ging Period	Maximum Predicted Concentration (μg/m³)				Background Concentration (μg/m³)	Highest Predicted CTG Concentration Plus Background Concentration (μg/m³)	Most Stringent Air Quality Standard (μg/m³)	Comply (Yes /No)
		CTG 1	CTG 2	CTG 3	CTG 4				
NO_2	1-hour	7.80	7.87	7.85	7.77	229.1	236.97	338	Yes
CO	1-hour	2.95	2.95	2.93	2.95	8,510	8512.95	23,000	Yes
	8-hour	1.51	1.51	1.51	1.51	4,544	4545.51	10,000	Yes

Commissioning

Table 12 above presented stack exhaust flow rates and temperatures for individual CTG commissioning tests. The applicant conducted modeling for the tests that were expected to produce the highest offsite concentrations at ground level (i.e., the test with either the highest hourly emission rate and/or the test with the lowest exhaust flow and temperature). For NOx, the emissions per hour are highest for the "Baseload AVR Commissioning" test, while the highest CO emission rate corresponds to the test described as "first fire the unit and then shutdown to check for leaks, etc." Since the exhaust gas flow rate and temperature are both lowest and CO emissions are highest for the latter test, it represents the worst-case commissioning scenario for 1-hour and 8-hour impacts of that pollutant. However, NOx emissions for both tests were modeled to provide results for the highest emission case and the lowest plume rise case to ensure that maximum 1-hour ground-level impacts for NO_2 would be addressed.

For NO_2 and CO, the table below shows, during commissioning, the highest predicted concentration for any CTG plus the background concentration does not exceed the most stringent air quality standard. Moreover, all four CTGs may be commissioned simultaneously without causing the NO2 or CO ambient standards to be exceeded. The commissioning of one or two CTGs at a time, however, is a more likely scenario.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Table 39--Model Results – Commissioning – Individual Turbine

Modeling Scenario	Pollutant	Averaging Period	Maximum Predicted Impact All 4 CTGs (µg/m³)	Maximum Estimated Impact per CTG (µg/m³)				Background (µg/m³)	Max Predicted Impact All 4 CTGs + Background Concentration (µg/m³)	Most Stringent Air Quality Standard (µg/m³)	Comply (Yes/No)
				CTG 1	CTG 2	CTG 3	CTG 4				
First Fire	CO	1 hour	123	35.66	35.2	35.65	35.67	8,510	8,633	23,000	Yes
		8 hour	104	28.58	29.19	31.87	31.63	4,544	4,648	10,000	Yes
	NO_2	1 hour	29.1	8.52	8.54	8.65	8.66	229.1	258.2	338	Yes
Base Load AVR	NO_2	1 hour	58.5	16.7	15.7	14.8	13.4	229.1	287.6	338	Yes

3. <u>A/N 476665--Ammonia Storage Tank</u>
   Modeling is not required because there will be no emissions.

4. <u>A/N 476666—Emergency ICE (Black Start Engine)</u>
   Non-RECLAIM Emissions—This engine is exempt from modeling requirements per Rule 1304(a)(4), which exempts a source exclusively used as emergency standby equipment.

   RECLAIM Emissions—This engine is exempt from modeling requirements per Rule 2005(k)(5), which exempts equipment used exclusively on a standby basis.

5. <u>A/N 481185—Oil Water Separator</u>
   Modeling is not required for VOC emissions.

- <u>*Rule 1303(b)(2)-Offsets*</u>
- <u>*Rule 2005(b)(2)-Offsets*</u>
  Offset requirements are explained above in the section on <u>Emissions Calculations, Offset Requirements/NSR Entries</u>.

The number of ERCs and RTCs required for each application and the total number required for the project are shown in the table below.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Table 40A—ERCs and RTCs Required ~~1. A/N 476651, 476656, 476659, 476661 Combustion Gas Turbines Nos. 1 - 4~~

Formatted: Normal, Centered, Indent: Hanging: 0.25"

A/N	Equipment	NOx RTCs for Commissioning Year, lb/yr	NOx RTCs for Normal Operating Year, lb/yr	VOC ERCs, lb/day	PM_{10} ERCs, lb/day	SOx ERCs, lb/day
476651	Turbine No. 1	~~9746~~ 9677	~~6960~~ 6886	6~~5~~	12	2~~1~~
476654	SCR/CO Oxidation Catalyst No. 1	0	0	0	0	0
476656	Turbine No. 2	~~9746~~ 9677	~~6960~~ 6886	5	12	1
476657	SCR/CO Oxidation Catalyst No. 2	0	0	0	0	0
476659	Turbine No. 3	~~9746~~ 9677	~~6960~~ 6886	5	12	1
476660	SCR/CO Oxidation Catalyst No. 3	0	0	0	0	0
476661	Turbine No. 4	~~9746~~ 9677	~~6960~~ 6886	5	12	1
476663	SCR/CO Oxidation Catalyst No. 4	0	0	0	0	0
476665	Ammonia Tank	0	0	0	0	0
476666	Emergency ICE, black start engine	2412	2412	0	0	0
481185	Oil Water Separator	0	0	0	0	0

Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Underline
Formatted: Strikethrough
Formatted: Underline
Formatted: Strikethrough
Formatted: Underline, Font color: Orange
Formatted: Underline, Font color: Orange
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Underline, Font color: Orange
Formatted: Underline, Font color: Orange
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Underline, Font color: Orange
Formatted: Underline, Font color: Orange
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Underline, Font color: Orange
Formatted: Underline, Font color: Orange

	Total Project	~~41,396~~ 41,120	~~30,252~~ 29,956	~~21~~ 20	48	~~5~~ 4

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Underline
Formatted: Strikethrough
Formatted: Underline
Formatted: Strikethrough
Formatted: Underline, Font color: Orange
Formatted: Underline, Not Strikethrough
Formatted: Underline, Font color: Orange
Formatted: Strikethrough

A summary of the applicant's compliance with the RTC and ERC requirements to date is provided in the table below.

Table 40B—Compliance with RTC and ERC Requirements~~VOC, PM_{10}, SOx—Since the maximum annual facility emissions for these pollutants are less than 4 tpy, no offsets are required.~~

~~NOx—Condition no. I296.1 requires NOx RTCs of 6640 lb/yr for the commissioning year and 3829 lb/yr for normal operating years.~~

Pollutant	Total Project Requirement	Compliance Status
NOx	~~41,396~~ 41,120 lb RTCs--Commissioning Year	As explained in condition nos. I296.1 and I296.2, the applicant is not required to hold these RTCs until before the operation of the equipment. Accordingly, the RTCs acquisition and transfer have not taken place.
NOx	~~30,252~~ 29,956 lb RTCs--Normal Operating Year	As explained in condition nos. I296.1 and I296.2, the applicant is not required to hold these RTCs until before the operation of the equipment. Accordingly, the RTCs acquisition and transfer have not taken place.
SOx	4 lb/day ERCs	The applicant has provided the purchase contract for the following: 4 lb/day of coastal SOx ERCs. The change of title application for the ERCs have been submitted and are pending. (See Table 40C below for details on the ERC certificate nos. and history.)
ROG	20 lb/day ERCs	The applicant ~~has provided the purchase contract~~ holds ERC certificates for the following:

Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Red, Strikethrough

		20 lb/day of coastal ROG ERCs. ~~The two change of title application for the ERCs have been submitted and are pending.~~ (See Table 40C below for details on the ERC certificate nos. and history.)
PM_{10}	48 lb/day ERCs	The applicant ~~has provided the purchase contract~~ holds ERC certificates for the following: 23 lb/day + 16 lb/day of coastal PM10 STERCs (short term ERCs) for years 2008 through 2014 and 23 lb/day + 16 lb/day of coastal PM10 STERCs for year 2015 and all subsequent years thereafter into perpetuity. 8 lb/day + 1 lb/day of coastal PM10 ERCs ~~The three change of title applications for the ERCs and the 56 change of title applications for the STERCs have been submitted and are pending.~~ (See Table 40C below for details on the ERC certificate nos. and history.) ***As the STERCs will be used in aggregate like ERCs, they will not be subject to special requirements or permit conditions.***

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

Formatted: Not Strikethrough

Formatted: Underline

Formatted: Font color: Red

Formatted: Font color: Red, Strikethrough

2. ~~A/N 476654, 476657, 476660, 476663 – Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 1-4~~
   ~~No offsets required because there are no increases in emissions subject to offsets.~~

3. ~~A/N 476665 – Ammonia Storage Tank~~
   ~~No offsets required because there are no increases in emissions.~~

4. ~~A/N 476666 – Emergency ICE (Black Start Engine)~~
   ~~VOC, PM_{10}, SOx – This engine is exempt from offset requirements per Rule 1304(a)(4), which exempts a source exclusively used as emergency standby equipment.~~

   ~~NOx – RECLAIM does not provide an exemption. Thus, condition no. I296.2 requires NOx RTCs of 2412 lb/yr for the commissioning year and normal operating years.~~

5. ~~A/N 481185 – Oil Water Separator~~
   ~~No offsets required because there are no increases in emissions.~~

6. ~~Total Project~~
   ~~VOC, PM_{10}, SOx – No offsets required because the facility emissions for each will be less than 4 tpy.~~

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

~~NOx For the commissioning yr, NOx RTCs of 28,972 lb/yr are required. [(6640 lb/yr per turbine) (4 turbines) + 2412 lb/yr black start engine = 28,972 lb/yr]~~

~~For normal operating yr, NOx RTCs of 17,728 lb/yr are required. [(3829 lb/yr per turbine) (4 turbines) + 2412 lb/yr black start engine = 17,728 lb/yr]~~

A summary of the change of title applications submitted by CPP is shown in the table below. The table includes the application nos., date of purchase, amount of ERCs; seller name and certificate number; and originator name, certificate number and zone.

Table 40C—ERC Certificates Nos. and History

Formatted: Centered

Formatted: Font color: Red, Strikethrough

Formatted: Font: 12 pt, Bold

	Canyon Power Plant					Seller of ERCs		Originator of ERCs		
Emittent	Cert. No.	Title Change Appl. No.	Date of Purchase	ERC Type	Amount (lb/day)	Name	Cert. No.	Name	Cert. No.	Zone
SOx	~~Pending~~+ AQ008862	492640	12/2/08	ERC	4	Olduvai Gorge, LLC	AQ008836	CBS Corp.	AQ000006	01-Coastal
				SOx Total	4					
ROG	~~Pending~~+ AQ008840	492645	12/2/08	ERC	10	Grey K Fund LP	AQ007231	Ringier America, Inc.	AQ000479	01-Coastal
ROG	~~Pending~~+ AQ008842	492643	12/2/08	ERC	10	Grey K Fund LP	AQ007237	Allied Signal, Inc.	AQ000652	01-Coastal
				ROG Total	20					
PM_{10}	~~Pending~~+ AQ008838	492654	12/1/08	ERC	1	Linn Western Operating Inc	AQ007191	Deluxe Laboratories	AQ000615	01-Coastal
PM_{10}	~~Pending~~+ AQ008844	492646	12/2/08	ERC	4	Olduvai Gorge, LLC	AQ006700	Intl Light Metals Corp	AQ001180	01-Coastal
PM_{10}	~~Pending~~+ AQ008846	492639	12/2/08	ERC	4	Olduvai Gorge, LLC	AQ006557	Commercial Enameling Co	AQ002062	01-Coastal
PM_{10}	~~Pending~~+ AQ008864	492597	12/2/08	STERC	2	Olduvai Gorge,	AQ008409	Pechiney Cast Plate Inc	AQ007936	01-Coastal
PM_{10}	~~Pending~~+	492598		STERC			AQ008411		AQ007937	

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted Table

Formatted: Font color: Red, Strikethrough

Formatted: Underline

Formatted: Underline, Not Strikethrough, Not Superscript/ Subscript

Formatted: Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT *ENGINEERING AND COMPLIANCE DIVISION*	PAGES 138	PAGE 112
	APPL. NO. 476650, -651, -654, -656, -657, -659, -660, -661, -663,-665, -666, 481185	DATE ~~61/2119/2009~~6/24/2009
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY V. Lee	CHECKED BY

	Canyon Power Plant					Seller of ERCs		Originator of ERCs		
Emittent	Cert. No.	Title Change Appl. No.	Date of Purchase	ERC Type	Amount (lb/day)	Name	Cert. No.	Name	Cert. No.	Zone
	AQ008866				(STERC	LLC				
PM_{10}	~~Pending~~+ AQ008868	492599		STERC	Stream)		AQ008413		AQ007938	
PM_{10}	~~Pending~~+ AQ008870	492600		STERC			AQ008415		AQ007939	
PM_{10}	~~Pending~~+ AQ008872	492601		STERC			AQ008417		AQ007940	
PM_{10}	~~Pending~~+ AQ008874	492602		STERC			AQ008419		AQ007941	
PM_{10}	~~Pending~~+ AQ008876	492587		STERC			AQ008421		AQ007942	
PM_{10}	~~Pending~~+ AQ008878	492588		STERC			AQ008423		AQ007943	
PM_{10}	~~Pending~~+ AQ008907	492589	12/2/08	STERC	1	Olduvai Gorge, LLC	AQ008425	Pechiney Cast Plate Inc.	AQ007945	01-Coastal
PM_{10}	~~Pending~~+ AQ008909	492590		STERC	(STERC Stream)		AQ008427		AQ007946	
PM_{10}	~~Pending~~+ AQ008911	492591		STERC			AQ008429		AQ007947	
PM_{10}	~~Pending~~+ AQ008913	492592		STERC			AQ008431		AQ007948	
PM_{10}	~~Pending~~+ AQ008915	492604		STERC			AQ008433		AQ007949	
PM_{10}	~~Pending~~+	492605		STERC			AQ008435		AQ007950	

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted Table

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Emittent	Canyon Power Plant					Seller of ERCs		Originator of ERCs		
	Cert. No.	Title Change Appl. No.	Date of Purchase	ERC Type	Amount (lb/day)	Name	Cert. No.	Name	Cert. No.	Zone
PM$_{10}$	AQ008917 ~~Pending~~+	492607		STERC			AQ008437		AQ007951	
PM$_{10}$	AQ008919 ~~Pending~~+	492608		STERC			AQ008439		AQ007952	
PM$_{10}$	AQ008921 ~~Pending~~+	492661	12/2/08	STERC	7 (STERC Stream)	Olduvai Gorge, LLC	AQ008353	Pechiney Cast Plate Inc.	AQ007927	01-Coastal
PM$_{10}$	AQ008891 ~~Pending~~+	492659		STERC			AQ008395		AQ007928	
PM$_{10}$	AQ008893 ~~Pending~~+	492658		STERC			AQ008397		AQ007929	
PM$_{10}$	AQ008895 ~~Pending~~+	492657		STERC			AQ008399		AQ007930	
PM$_{10}$	AQ008897 ~~Pending~~+	492656		STERC			AQ008401		AQ007931	
PM$_{10}$	AQ008899 ~~Pending~~+	492655		STERC			AQ008403		AQ007932	
PM$_{10}$	AQ008901 ~~Pending~~+	492595		STERC			AQ008405		AQ007933	
PM$_{10}$	AQ008903 ~~Pending~~+	492596		STERC			AQ008407		AQ007934	
PM$_{10}$	AQ008905 ~~Pending~~+	492668	12/2/08	STERC	6	Olduvai Gorge.	AQ008010	Los Angeles Export Terminal	AQ007758	01-Coastal
PM$_{10}$	AQ009059 ~~Pending~~+	492667		STERC			AQ008012		AQ007759	

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted Table

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

Formatted: Underline, Font color: Red

	Canyon Power Plant					Seller of ERCs		Originator of ERCs		
Emittent	Cert. No.	Title Change Appl. No.	Date of Purchase	ERC Type	Amount (lb/day)	Name	Cert. No.	Name	Cert. No.	Zone
	AQ009061				(STERC	LLC		Inc		
PM_{10}	~~Pending~~[1] AQ009063	492666		STERC	Stream)		AQ008014		AQ007760	
PM_{10}	~~Pending~~[1] AQ009065	492665		STERC			AQ008016		AQ007761	
PM_{10}	~~Pending~~[1] AQ009067	492664		STERC			AQ008018		AQ007762	
PM_{10}	~~Pending~~[1] AQ009069	492663		STERC			AQ008020		AQ007763	
PM_{10}	~~Pending~~[1] AQ009071	492662		STERC			AQ008022		AQ007764	
PM_{10}	~~Pending~~[1] AQ009073	492660		STERC			AQ008024		AQ007765	
PM_{10}	~~Pending~~[1] AQ009027	493223	12/5/08	STERC	2	Olduvai	~~Pending~~[2] AQ008934	Commonwealth	AQ008497	01-
PM_{10}	~~Pending~~[1] AQ009029	493222		STERC		Gorge, LLC	~~Pending~~[2] AQ008936	Aluminum Concast	AQ008498	Coastal
PM_{10}	~~Pending~~[1] AQ009031	493221		STERC	(STERC Stream)		~~Pending~~[2] AQ008938		AQ008499	
PM_{10}	~~Pending~~[1] AQ009033	493224		STERC			~~Pending~~[2] AQ008940		AQ008500	
PM_{10}	~~Pending~~[1] AQ009035	493225		STERC			~~Pending~~[2] AQ008942		AQ008501	
PM_{10}	~~Pending~~[1]	493226		STERC			~~Pending~~[2]		AQ008502	

Formatted ... [1]
Formatted Table ... [2]
Formatted ... [3]
Formatted ... [4]
Formatted ... [5]
Formatted ... [6]
Formatted ... [7]
Formatted ... [8]
Formatted ... [9]
Formatted ... [11]
Formatted ... [13]
Formatted ... [15]
Formatted ... [10]
Formatted ... [12]
Formatted ... [17]
Formatted ... [14]
Formatted ... [16]
Formatted ... [18]
Formatted ... [20]
Formatted ... [19]
Formatted ... [21]
Formatted ... [23]
Formatted ... [22]
Formatted ... [24]
Formatted ... [26]
Formatted ... [25]
Formatted ... [27]
Formatted ... [28]

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

ENGINEERING AND COMPLIANCE DIVISION

APPLICATION PROCESSING AND CALCULATIONS

PAGES 138	PAGE 115
APPL. NO. 476650, -651, -654, -656, -657, -659, -660, -661, -663,-665, -666, 481185	DATE ~~61/2119/2009~~6/24/2009
PROCESSED BY V. Lee	CHECKED BY

	Canyon Power Plant					Seller of ERCs		Originator of ERCs		
Emittent	Cert. No.	Title Change Appl. No.	Date of Purchase	ERC Type	Amount (lb/day)	Name	Cert. No.	Name	Cert. No.	Zone
PM_{10}	AQ009037 ~~Pending~~+	493227		STERC			AQ008944 ~~Pending~~[2]		AQ008503	
PM_{10}	AQ009039 ~~Pending~~+	493228		STERC			AQ008946 ~~Pending~~[2]		AQ008504	
PM_{10}	AQ009041 ~~Pending~~+	493229	12/5/08	STERC	19 (STERC Stream)	Olduvai Gorge, LLC	AQ008948 ~~Pending~~[2]	Commonwealth Aluminum Concast	AQ008516	01-Coastal
PM_{10}	AQ009043 ~~Pending~~+	493231		STERC			AQ008950 ~~Pending~~[2]		AQ008517	
PM_{10}	AQ009045 ~~Pending~~+	493234		STERC			AQ008952 ~~Pending~~[2]		AQ008518	
PM_{10}	AQ009047 ~~Pending~~+	493233		STERC			AQ008954 ~~Pending~~[2]		AQ008519	
PM_{10}	AQ009049 ~~Pending~~+	493236		STERC			AQ008956 ~~Pending~~[2]		AQ008520	
PM_{10}	AQ009051 ~~Pending~~+	493237		STERC			AQ008958 ~~Pending~~[2]		AQ008521	
PM_{10}	AQ009053 ~~Pending~~+	493239		STERC			AQ008960 ~~Pending~~[2]		AQ008522	
PM_{10}	AQ009055 ~~Pending~~+	493240		STERC			AQ008962 ~~Pending~~[2]		AQ008523	
PM_{10}	AQ009057 ~~Pending~~+	493242	12/5/08	STERC	2	Olduvai Gorge,	AQ008964 ~~Pending~~[2]	Commonwealth Aluminum	AQ008682	01-Coastal
PM_{10}	AQ009325 ~~Pending~~+	493243		STERC			AQ008979 ~~Pending~~[2]		AQ008683	

Formatted ... [29]
Formatted Table ... [30]
Formatted ... [31]
Formatted ... [32]
Formatted ... [34]
Formatted ... [33]
Formatted ... [35]
Formatted ... [37]
Formatted ... [36]
Formatted ... [38]
Formatted ... [40]
Formatted ... [42]
Formatted ... [44]
Formatted ... [39]
Formatted ... [41]
Formatted ... [46]
Formatted ... [43]
Formatted ... [45]
Formatted ... [47]
Formatted ... [49]
Formatted ... [48]
Formatted ... [50]
Formatted ... [52]
Formatted ... [51]
Formatted ... [53]
Formatted ... [55]
Formatted ... [54]
Formatted ... [56]
Formatted ... [58]
Formatted ... [57]
Formatted ... [59]
Formatted ... [61]
Formatted ... [60]
Formatted ... [62]
Formatted ... [64]
Formatted ... [63]
Formatted ... [65]
Formatted ... [67]
Formatted ... [69]
Formatted ... [70]
Formatted ... [66]
Formatted ... [68]
Formatted ... [71]

	Canyon Power Plant					Seller of ERCs		Originator of ERCs		
Emittent	Cert. No.	Title Change Appl. No.	Date of Purchase	ERC Type	Amount (lb/day)	Name	Cert. No.	Name	Cert. No.	Zone
	AQ009327				(STERC Stream)	LLC	AQ008981	Concast		
PM_{10}	~~Pending~~[1] AQ009329	493244		STERC			~~Pending~~[2] AQ008983		AQ008684	
PM_{10}	~~Pending~~[1] AQ009331	493246		STERC			~~Pending~~[2] AQ008985		AQ008685	
PM_{10}	~~Pending~~[1] AQ009333	493247		STERC			~~Pending~~[2] AQ008987		AQ008686	
PM_{10}	~~Pending~~[1] AQ009335	493248		STERC			~~Pending~~[2] AQ008989		AQ008687	
PM_{10}	~~Pending~~[1] AQ009337	493249		STERC			~~Pending~~[2] AQ008991		AQ008688	
PM_{10}	~~Pending~~[1] AQ009339	493250		STERC			~~Pending~~[2] AQ008993		AQ008689	
				PM_{10} Total	**48**					

~~[1] The ERC certificate nos. for the CPP will be assigned once the District approves the change of title applications submitted by the CPP.~~

~~[2] The ERC certificate nos. for Olduvai Gorge, LLC will be assigned once the District approves the change of title applications submitted by Olduvai Gorge. The CPP purchased these STERCs from Olduvai Gorge, which in turn purchased them from Commonwealth Aluminum Concast. Therefore, the change of title applications for Olduvai Gorge will be processed before the change of title applications for CPP.~~

Formatted ... [72]
Formatted Table ... [73]
Formatted ... [76]
Formatted ... [74]
Formatted ... [75]
Formatted ... [78]
Formatted ... [77]
Formatted ... [79]
Formatted ... [81]
Formatted ... [80]
Formatted ... [82]
Formatted ... [84]
Formatted ... [83]
Formatted ... [85]
Formatted ... [87]
Formatted ... [86]
Formatted ... [88]
Formatted ... [90]
Formatted ... [89]
Formatted ... [91]
Formatted ... [93]
Formatted ... [92]
Formatted ... [94]
Formatted ... [95]
Formatted ... [96]

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Rule 1303(b)(3)-Sensitive Zone Requirements
Rule 2005(e)-Trading Zone Restrictions

Both rules provide that credits shall be obtained from the appropriate trading zone. Rule 1303(b)(3) is not applicable because offsets will not be required. Rule 2005(e) is applicable because RTCs will be required. Anaheim is located in Zone 1 (coastal). A facility in Zone 1 may only obtain RTCs from Zone 1. Compliance is expected.

Rule 1303(b)(4)-Facility Compliance

This new facility will comply with all applicable rules and regulations of the District, as required by this rule.

Rule 1303(b)(5)-Major Polluting Facilities
Rule 2005(g)—Additional Federal Requirements for Major Stationary Sources

- *Rule 1303(b)(5)(B) – Statewide Compliance*
- *Rule 2005(g)(1) – Statewide Compliance*

  Rule 1303(b)(5)(B) requires a demonstration that all major stationary sources are owned or operated by such person in the state are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Rule 2005(g)(1) requires the applicant to certify that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards.

  The owner is the SCPPA, a consortium. The operator/applicant is the City of Anaheim Public Utilities Dept. The District has interpreted these provisions to apply to the City of Anaheim Public Utilities Dept. A letter from Steve Sciortino, dated 7/3/08, certified that all sources under common ownership within the District are in compliance with all the applicable District Rules, variances, orders and settlement agreements. A list of facilities was received on 7/22/08. I checked each facility on the District's Compliance Tracking System and verified each facility is in compliance. The letter is more inclusive than required for Rules 1303(b)(5)(B) and 2005(g)(1), because the primary purpose was for compliance with Rule 1309.1, which is no longer applicable.

  The list of facilities with compliance status is presented in the table below.

Table ~~43~~41—Compliance Status of Stationary Sources Operated by Applicant

Facility ID	Facility	Location Address	Compliance Tracking System—In Compliance?
56940	City of Anaheim/ Comb Turbine Gen Station	1144 N. Kraemer Blvd. Anaheim, CA 92806	Yes
79365	Anaheim City Public Utilities Dept.	1411 N. Tustin Ave. Anaheim, CA 92807	Yes

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

80050	Anaheim City, Public Utilities Dept.	1664 S. Brookhurst St. Anaheim, CA 92804	Yes
124175	City of Anaheim, Public Utilities Dept.	1713 Clementine Anaheim, CA 92802	Yes
80049	Anaheim Public Utilities Dept., Env Svcs Div	2004 S. West St. Anaheim, CA 92802	Yes
132216	City of Anaheim	2204 E. Katella Ave Anaheim, CA 92806	Yes
66215	Anaheim City, Public Utilities Dept.	555 S. Silverado Way Anaheim, CA 92807	Yes
77894	Anaheim City, Public Utilities Dept.	770 S. Nohl Canyon Rd Anaheim, CA 92807	Yes
47831	Anaheim City, Public Utilities Dept.	6751 Walnut Canyon Rd Anaheim, CA 92807	Yes
66212	Anaheim City, Public Utilities Dept.	7020 E. Serrano Anaheim, CA 92803	Yes
80787	Anaheim City, Public Utilities Dept.	8103 E. Serrano Ave Anaheim, CA 92808	Yes
77049	Anaheim City, Public Utilities Dept.	826 E. Cerritos Ave Anaheim, CA 92805	Yes
77048	Anaheim City, Public Utilities Dept.	826 W. La Palma St. Anaheim, CA 92805	Yes
63088	City of Anaheim, Public Utilities Dept.	8315 E. Canyon Vista Anaheim, CA 92808	Yes
136278	City of Anaheim	847 S. East St. Anaheim, CA 92805	Yes
142820	City of Anaheim, Well #53	1211 S. Magnolia Ave Anaheim, CA 92804	Yes
5704	Anaheim City, Public Utilities Dept.	909 E. Vermont Ave. Anaheim, CA 92805	Yes

- *Rule 1303(b)(5)(C) – Protection of Visibility*
- *Rule 2005(g)(4)—Protection of Visibility*

Rule 1303(b)(5)(C) requires a modeling analysis for plume visibility if the net emission increase from a new or modified sources exceeds 15 tpy of PM_{10} or 40 tpy of NOx; and the location of the source, relative to the closest boundary of a specified Federal Class I area, is within the distance specified in Table C-1 of the rule. Rule 2005(g)(4) imposes the same requirements for NOx. Since the increases in PM_{10} and NOx emissions from the CPP project do not exceed the respective thresholds, these provisions are not applicable.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

- *Rule 1303(b)(5)(A) – Alternative Analysis*
- *Rule 2005(g)(2)—Alternative Analysis*
- *Rule 1303(b)(5)(D) – Compliance through CEQA*
- *Rule 2005(g)(3)—Compliance through CEQA*

For a new major polluting facility, Rule 1303(b)(5)(A) requires an analysis of alternative sites, sizes, production processes, and environmental control techniques and a demonstration that the benefits of the proposed project outweigh the environmental and social costs associated with that project. For a new RECLAIM major stationary source, Rule 2005(g)(2) requires an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction, or modification.

Rule 1303(b)(5)(D) specifies the requirements of subparagraph (b)(5)(A) may be met through compliance with CEQA. Rule 2005(g)(3) specifies the requirements of paragraph (g)(2) may be met through CEQA analysis.

The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. The CEC's 12-month permitting process is a certified regulatory program under CEQA and includes various opportunities for public and inter-agency participation. SCPPA submitted an AFC to the CEC on December 28, 2007 seeking certification for the new power plant. The AFC describes alternative site locations in Section 5.4, and alternative energy generation technologies in Section 5.5. The proposed site was determined to be the least environmentally sensitive site based on the proximity of sensitive receptors, biological resources and land use compatibility. The conventional simple-cycle combustion turbine technology using natural gas was determined to be the best available technology for a peaking plant service after a review of all feasible technologies that might be available for peaking load operation using a methodology that considered commercial availability, ability to implement, and cost-effectiveness.

Rule 1401 – New Source Review of Toxic Air Contaminants
Rule 2005(i) – RECLAIM Rule 1401 Compliance

Rule 1401 specifies limits for maximum individual cancer risk (MICR), cancer burden, and noncancer acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permits that emit toxic air contaminants. Rule 2005(j) requires compliance with Rule 1401 for NOx emissions.

Rule 1401 requirements are summarized below.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Table ~~40~~42 – Rule 1401 Requirements

Parameters	Rule 1401 Limits
MICR, without T-BACT	$\leq 1x10^{-6}$
MICR, with T-BACT	$\leq 1x10^{-5}$
Acute Hazard Index	≤ 1.0
Chronic Hazard Index	≤ 1.0
Cancer Burden	≤ 0.5

As discussed above, the applicant provided a revised modeling analysis for air quality modeling and health risk assessment on September 12, 2008, supplemented with a second revised modeling analysis submitted on December 16, 2008.

For the health risk assessments, ~~T~~the applicant performed a refined SCAQMD Tier 4 and OEHHA Tier 1 health risk assessment using the CARB Hotspots Analysis and Reporting Program (HARP), Version 1.4. As discussed above for the modeling, the District modeling staff reviewed the applicant's two modeling analyses for both air quality modeling and health risk assessment. The review concluded the health risk assessments ~~is~~are acceptable. (See memorandu~~m~~a from Naveen Berry to Mike Mills, dated 10/16/08 and 1/13/09.)

The HRA included an assessment of the maximum impact due to each permit unit, i.e., the highest MICR, HIC, and HIA *regardless of receptor location*, to demonstrate compliance with Rule 1401. The table below demonstrates all four turbines are in compliance with the MICR limit of 1 in a million, the chronic and acute hazard index limits of 1.0, and the cancer burden limit of 0.5. **Thus, the turbines will be in compliance with Rule 1401**. The table also confirms the risk for the cooling tower is less than one in a million and therefore exempt from permitting. The results for the black start engine are shown here for informational purposes only, because Rule 1401(g)(1)(F) exempts emergency ICEs.

Formatted: Font: Italic, No underline

Table ~~41~~43--Maximum Impacts due to Each Permit Unit

Permit Unit	Cancer Risk (per million)				Cancer burden (based on a 1 in 1 million risk)
	MICR	UTM Easting (m)	UTM Northing (m)	Description of location of impact	
Turbine 1	0.0061~~0.0053~~	422268	3748871	grid ~2.7 km northeast	0
Turbine 2	0.0061~~0.0052~~	422268	3748871	grid ~2.9 km northeast	0
Turbine 3	0.0061~~0.0052~~	422268	3748871	grid ~2.9 km northeast	0
Turbine 4	0.0061~~0.0053~~	422268	3748871	grid ~2.9 km northeast	0

Cooling Tower	0.0365~~0.0203~~	420287	3746910	northern property boundary	0
Black Start Engine	0.6090	420263	3746903	northern property boundary	0
Permit Unit	**Chronic Hazard Index**				
	HIC	**UTM Easting (m)**	**UTM Northing (m)**	**Description of location of impact**	
Turbine 1	0.0001	422268	3748871	grid ~2.7 km northeast	
Turbine 2	0.0001	422268	3748871	grid ~2.7 km northeast	
Turbine 3	0.0001	422268	3748871	grid ~2.7 km northeast	
Turbine 4	0.0001	422268	3748871	grid ~2.7 km northeast	
Cooling Tower	~~0.0039~~0.0070	420287	3746910	northern property boundary	
Black Start Engine	0.0004	420263	3746903	northern property boundary	
Permit Unit	**Acute Hazard Index**				
	HIA	**UTM Easting (m)**	**UTM Northing (m)**	**Description of location of impact**	
Turbine 1	0.0041	422672	3744681	grid ~3.1 km southeast	
Turbine 2	0.0041	422572	3744781	grid ~3 km southeast	
Turbine 3	0.0041	422572	3744781	grid ~3 km southeast	
Turbine 4	0.0041	422519	3744925	grid ~2.8 km southeast	
Cooling Tower	0.0004	420287	3746910	northern property boundary	
Black Start Engine	NA	NA	NA	NA	

Note: The following East package receptors are onsite, and thus the predicted risk is ignored at receptors 12322 and 12444-5.
Note: Only the east receptor package was examined since all of the peak impacts occurred there.
Note: Cancer burden based on a 1 in 1 million risk level. If the peak cancer risk is < 1 in a million then the cancer burden is 0.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Pursuant to the District's request, the HRA also included an assessment of the maximum residential and commercial impacts due to each permit unit, i.e., the highest MICR, HIC, and HIA for residential and commercial receptors. This information will be included in the public notice for this project for informational purposes. The HRA examined the nearest residences and offsite commercial facilities as it was not practical to identify every residence and/or business within 10 kilometers of the project. The results are summarized in the table below.

Table ~~42~~44–Maximum Residential and Commercial Impacts due to Each Permit Unit

Source	Cancer Risk (in 1 million)							
	Residential				Commercial			
	MICR	UTM Easting (m)	UTM Northing (m)	Description of location of impact	MICR	UTM Easting (m)	UTM Northing (m)	Description of location of impact
Gas Turbine No. 1	0.0052~~0.0045~~	422484	3749818	Harmony Home (~3.5 km NE)	2.94E-05~~2.51E-05~~	420292	3746942	Woodridge Press (~25m N of fence)
Gas Turbine No. 2	0.0053~~0.0046~~	422484	3749818	Harmony Home (~3.5 km NE)	2.91E-05~~2.49E-05~~	420183	3746896	Euro Sport Accessories Inc (~35m N of fence)
Gas Turbine No. 3	0.0053~~0.0046~~	422484	3749818	Harmony Home (~3.5 km NE)	2.82E-05~~2.41E-05~~	420374	3746808	Reel lumber service warehouse(~15m E of fence)
Gas Turbine No. 4	0.0053~~0.0046~~	422484	3749818	Harmony Home (~3.5 km NE)	2.79E-05~~2.38E-05~~	420374	3746808	Reel lumber service warehouse(~15m E of fence)
Black start Engine	0.0910	419925	3746623	Resident about 250 m west of fence	0.083	420292	3746942	Woodridge Press (~25m N of fence)
Cooling Tower	0.0065~~0.0036~~	420880	3746899	Resident about 500 m east of fence	0.011~~0.006~~	420292	3746942	Woodridge Press (~25m N of fence)

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Total Project	0.1000~~0.0969~~	419563	3746289	Resident about 700 m southwest of fence	0.09318~~0.0885~~	420292	3746942	Woodridge Press (~25m N of fence)

Chronic Non-cancer Hazard Index

Source	Residential				Commercial			
	HIC	**UTM Easting (m)**	**UTM Northing (m)**	**Description of location of impact**	**HIC**	**UTM Easting (m)**	**UTM Northing (m)**	**Description of location of impact**
Gas Turbine No. 1	0.0001	422484	3749818	Harmony Home (~3.5 km NE)	3.40E-06~~1.89E-06~~	420292	3746942	Woodridge Press (~25m N of fence)
Gas Turbine No. 2	0.0001	422484	3749818	Harmony Home (~3.5 km NE)	3.37E-06~~1.87E-06~~	420183	3746896	Euro Sport Accessories Inc (~35m N of fence)
Gas Turbine No. 3	0.0001	422484	3749818	Harmony Home (~3.5 km NE)	3.26E-06~~1.81E-06~~	420374~~420183~~	37468083[illegible]	Reel lumber service warehouse (~15m E of [illegible] ~~Sport Accessories Inc (~35m N of fence)~~
Gas Turbine No. 4	0.0001	422484	3749818	Harmony Home (~3.5 km NE)	~~1.79E-06~~3.22E-06	420374	3746808	Reel lumber service warehouse(~15m E of fence)
Black start Engine	0.0001	419925	3746623	Resident about 250 m west of fence	2.63E-04	420292	3746942	Woodridge Press (~25m N of fence)
Cooling Tower	0.0013~~0.0007~~	420880	3746899	Resident about 500 m east of fence	8.66E-03~~4.81E-03~~	420292	3746942	Woodridge Press (~25m N of fence)
Total Project	0.0014~~0.0008~~	420880	3746899	Resident about 500 m east of fence	0.00894~~0.0051~~	420292	3746942	Woodridge Press (~25m N of fence)

Formatted Table

Acute Non-cancer Hazard Index

Source	Residential				Commercial			
	HIA	**UTM Easting (m)**	**UTM Northing (m)**	**Description of location of impact**	**HIA**	**UTM Easting (m)**	**UTM Northing (m)**	**Description of location of impact**

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Gas Turbine No. 1	0.0040	420420	3750043	Atria Senior Living Group: Atria De Palma (~3km N)	7.02E-05	420344	3746992	Kraemer Auto Collision Center (~85m NE of fence)
Gas Turbine No. 2	0.0040	420420	3750043	Atria Senior Living Group: Atria De Palma (~3km N)	6.44E-05	420344	3746992	Kraemer Auto Collision Center (~85m NE of fence)
Gas Turbine No. 3	0.0040	420420	3750043	Atria Senior Living Group: Atria De Palma (~3km N)	5.94E-05	420344	3746992	Kraemer Auto Collision Center (~85m NE of fence)
Gas Turbine No. 4	0.0040	420420	3750043	Atria Senior Living Group: Atria De Palma (~3km N)	5.52E-05	420344	3746992	Kraemer Auto Collision Center (~85m NE of fence)
Black start Engine	0	NA	NA	NA	0	NA	NA	NA
Cooling Tower	0.0001	420186	3750043	Resident about 450 m south of fence	3.76E-04	420183	3746896	Euro Sport Accessories Inc (~35m N of fence)
Total Project	0.0161	420420	3750043	Atria Senior Living Group: Atria De Palma (~3km N)	0.00057	420183	3746896	Euro Sport Accessories Inc (~35m N of fence)

Note the CPP operates continuously and thus the default GLC and exposure assumptions were used to estimate the offsite worker cancer risk.

Rule 1470—Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines

This rule applies to new and in-use prime and emergency stationary compression ignition (CI) engines rated at greater than 50 bhp. As the black start engine is a new emergency stationary CI engine, the following discusses the applicable requirements.

- Rule 1470(c)(1)(A)(i)—This requires the use of CARB diesel fuel. The use of No. 2 diesel fuel will satisfy this requirement.

- Rule 1470(c)(2)(A)—This imposes requirements on new emergency ICEs located 500 ft or less from a school. As the nearest school, Melrose Elementary, is located 3749 ft away, these requirements are not applicable.

- Rule 1470(c)(2)(C)(i)(I)—This limits the diesel PM to 0.15 g/bhp-hr. As the AQMD-certified PM emissions level for this engine is 0.06 g/bhp-hr, this requirement is satisfied. Since the proposed CleanAIR Systems PERMIT™ Model FDA225 diesel particulate filter is CARB certified for 85% reduction, the PM emissions is anticipated to be further reduced to 0.009 g/bhp-hr.

- Rule 1470(c)(2)(C)(i)(III)—This limits engine operation to no more than 50 hours for maintenance and testing, which will be implemented by condition no. C1.1.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

REGULATION XVII – Prevention of Significant Deterioration

The federal Prevention of Significant Deterioration (PSD) has been established to protect deterioration of air quality in those areas that already meet the NAAQS. This regulation sets forth preconstruction review requirements for stationary sources to ensure that air quality in clean air areas does not significantly deteriorate while maintaining a margin for future industrial growth. Specifically, the PSD program establishes allowable concentration increases for attainment pollutants due to new or modified emission sources that are classified as major stationary sources.

Effective upon delegation by EPA, this regulation shall apply to preconstruction review of stationary sources that emit attainment air contaminants. On 3/3/03, EPA had rescinded its delegation of authority to the AQMD. On 7/25/07, the EPA and AQMD signed a new "Partial PSD Delegation Agreement." The agreement is intended to delegate the authority and responsibility to the District for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not set forth in AQMD Regulation XVII. The Partial Delegation agreement also did not delegate authority and responsibility to AQMD to issue new or modified PSD permits based on Plant-wide Applicability Limits (PALS) provisions of 40 CFR 52.21.

Rule 1701(b)(1) provides that BACT requirements applies to a net emission increase of a criteria air contaminant from a permit unit at any source. **Rule 1703(a)(2)** requires each permit unit to be constructed using BACT for each criteria air contaminant for which there is a net emission increase. The District is presently designated in attainment with NAAQS for sulfur dioxide, nitrogen dioxide, carbon monoxide, and lead. Consequently, BACT requirements for SOx, NOx, and CO reflected in the "Emissions and Requirements" column and in the permit conditions are tagged with "Rule 1703(a)(2) – PSD – BACT." The BACT analysis is presented above under the New Source Review discussion.

Rule 1701(b)(2) provides that all of the requirements of this regulation apply, except exempted in Rule 1704, to a new source or modification at an existing source where the increase in potential to emit is at least 100 or 250 tons of attainment air contaminants per year, depending on the source category. The 250 tpy threshold limit is applicable to the CPP, because it is not one of the 28 source categories subject to the 100 tpy threshold listed in Rule 1702(m)(1). One of the source categories subject to the 100 tpy threshold is a fossil fuel-fired steam electric plants of more than 250 million BTU/hr, but this refers to a combined cycle plant, not a simple cycle plant like the CPP. Because the maximum CO and NOx emissions during any year are below the 250 tons/yr threshold, the *CPP is **not** subject to PSD requirements other than the BACT requirements required by Rule 1701(b)(1).*

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted: Font: Italic, No underline

REGULATION XX—Regional Clean Air Incentives Market (RECLAIM)

- *Rule 2001--Applicability*
  NOx emissions are anticipated to exceed 4 TPY, which is the threshold for inclusion in the RECLAIM program. Although CPP would not have been subject to the RECLAIM requirements until it reported annual emissions of 4 TPY or more, it has opted into the RECLAIM program at this time via an opt-in letter, dated March 26, 2008, from Steve Sciortino. An advantage to entering the RECLAIM program at this point is that total facility emissions will be offset with RTCs at a 1-to-1 ratio before any operation (including testing) commences, instead of with ERCs at a 1.2-to-1 ratio before the P/Cs are issued.

- *Rule 2005—New Source Review for RECLAIM*
  See discussion above under New Source Review.

- *Rule 2012-RECLAIM Monitoring Recording and Recordkeeping Requirements*
  1. A/N 476651, 476656, 476659, 476661—Compression Turbine Generators Nos. 1 - 4
     Rule 2012(e)(1)(D) classifies a "peaking unit" as a "RECLAIM process unit." Rule 2012 Protocol-Attachment F-Definitions defines a "peaking unit" as "a turbine used intermittently to produce energy on a demand basis and does not operate more than 1300 hours per year." The CTGs fall under this definition as each CTG will operate 698.75 hours. The CTGs will be RECLAIM major NOx sources, however, based on Rule 2012(c)(1)(I), which classifies as a "major source" any NOx source or process unit required to be monitored and to report emissions with a CEMS. Each CTG is required to be equipped with a CEMs to verify compliance with the NOx BACT limit.

     Rule 2012(h)(5) provides that the Facility Permit holder of a new facility which elects to enter RECLAIM or a facility that is required to enter RECLAIM shall install all required or elected monitoring, reporting, and recording systems no later than 12 months after entry into RECLAIM. During the 12 months prior to the installation of

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

the required or elected monitoring, reporting and recordkeeping systems, the Facility Permit holder shall comply with the monitoring, reporting, and recordkeeping requirements of paragraphs (h)(2) and (h)(3) of this rule. (Condition D82.2 implements this requirement.) Paragraph (h)(2) provides that interim reports shall be submitted monthly for major and large sources. Paragraph (h)(3) provides that the Facility Permit holder shall install, maintain, and operate a totalizing fuel meter for each major source. Rule 2012, Appendix A, Chapter 2 states on pg. Rule 2012A-2-1 that major sources shall be allowed to use an interim reporting procedure to measure and record NOx emissions on a monthly basis according to the requirements specified in Chapter 3 for large sources. Chapter 3 states on pg. Rule 2012A-3-1 that the interim reporting is specified in subdivision D, paragraph 1. Paragraph 1, in turn, provides that the interim reporting shall be based on fuel usage and emission factor(s).

Thus, the facility permit is required to set forth the NOx emission factors for use in the interim reporting period before the CEMS is certified. Condition A99.4 specifies the interim emission factor for the commissioning period during which the CTGs are assumed to be operating at uncontrolled levels. From Table 15 above, the emission factor is ~~80.26~~ 98.16 lb/mmcf. Condition A99.5 specifies the interim emission factor for the normal operating period after commissioning has been completed and before the CEMS is certified, during which the CTGs are assumed to be operating at BACT levels. From Table 23 above, the emission factor is ~~11.56~~11.65 lb/mmcf.

2. A/N 476666—Emergency ICE (Black Start Engine)
The black start engine will be a RECLAIM process unit based on Rule 2012(e)(1)(D), which classifies as a "process unit" any emergency standby equipment.

The RECLAIM emission factor is based on the BACT limit, which is 4.80 g/bhp-hr for NOx + ROG. As BACT for NOx is not provided, the entire 4.8 g/bhp-hr is used as the emission factor.

EF = (4.8 g/bhp-hr) (1 lb/454 g) (1 hr/53.5 gal from Caterpillar specs)
(1000 gal/mgal) (1141 bhp) = 225.48 lb/mgal

REGULATION XXX – Title V
CPP is subject to the Title V requirements because it will be a major source and because it will be subject to the federal acid rain program as it will operate CTGs that are rated over 25 MW. Accordingly, an initial Title V application, A/N 476650, has been submitted. The Title V permit is required to contain the information specified under Rule 3004, including all emission limitations and operational requirements that assure compliance with all applicable regulations, any periodic monitoring requirements, and any necessary recordkeeping to

substantiate the facility's compliance status. As a new Title V facility, the proposed permit is subject to a 30-day public notice period (Rule 3006) and a 45-day EPA review and comment period (Rule 3003). In addition, any person may request a public hearing on the permit within 15 days of the publication of the notice (Rule 3006). The Title V public notice period ~~will~~ was anticipated to run concurrently with the Rule 212(g) public notice period for a single 30-day public comment period. (The Rule 212(g) public notice requirements are discussed above under *Rule 212-Standards for Approving Permits*.)

- ***Public Notice Distribution and Publication***

  On February 20, 2009, the AQMD e-mailed the Rules 212 and 3006 public notice, proposed Title V permit, and preliminary engineering analysis to the EPA , which started the 45-day EPA review and comment period.

  Also on February 20, 2009, the AQMD sent a copy of the application, draft permit, and engineering analysis to the Anaheim Main Public Library and AQMD library for display. On February 24, the AQMD mailed the public notice, with a stated distribution date of February 25, 2009, to approximately 2300 interested parties on the applicable CEC mailing lists and AQMD subscription lists. On February 25, the public notice was published in The Register as required by Rule 212(g)(2). Therefore, the 30-day public notice period started on February 25 and ended on March 27, 2009.

  On April 23, 2009, the applicant's representative finally mailed the public notice to addresses with ½ mile (not ¼ mile) radius of the project, as required by Rule 212(d). Therefore, since the public notice was drafted for Rule 212 and 3006, another 30-day public notice period started on April 23 and ended on May 23, 2009.

- ***EPA Comments***

  The EPA did not provide comments.

- ***Public Hearing Requests and Public Notice Comments***

  The City of Yorba Linda submitted a public hearing request, dated March 10, 2009. The City of Placentia submitted a public hearing request, dated March 12, 2009. (In addition, the City of Placentia submitted a comment letter, dated March 23, 2009, which stated that the project should incorporate a combined cycle system instead of simple cycle technology.) Both requests were submitted within the allowed 15-day period. Both requested further evaluation of project alternatives, specifically why Anaheim did not propose a combined cycle project. In addition, Yorba Linda questioned the contents and timing of SCPPA status reports submitted to the CEC, the contents of CEC status reports, the selection of documents posted on the CEC website, the timing of these postings, the economics of the project and why the number of start-ups had changed from the initial proposal. These requests were evaluated and found to not meet the public hearing criteria specified in Rule 3006(a)(1)(F). This subparagraph specifies that the request shall include all of the following information: (1) specific identification of the portion or

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"
Formatted: Underline
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red, Strikethrough
Formatted: Underline
Formatted: No underline
Formatted: Underline, Font color: Red
Formatted: Font: Italic
Formatted: Font: Italic
Formatted: Bullets and Numbering
Formatted: Font: Bold, Italic
Formatted: Indent: Left: 0.5"
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Light Blue
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Bullets and Numbering
Formatted: Indent: Left: 0.5"
Formatted: Font: Italic
Formatted: Bullets and Numbering
Formatted: Font: Italic
Formatted: Font: Bold, Italic
Formatted: Indent: Left: 0.5"

portions of the proposed permit or revision to which objection is made; (2) specific identification of the regulatory requirement or requirements, or provisions of these rules, with which the proposed permit or revision is inconsistent, and the reasons the inconsistency is believed to exist; (3) identification of proposed permit terms or conditions, if any, which would eliminate the inconsistency; and (4) a statement of the reason or reasons the requester believes a public hearing would clarify one or more issues involved in the permit decision. As the requests did not meet the public hearing criteria, a Title V public hearing was not required. However, in order to provide the Cities and the public in general an added opportunity to provide additional comments and input, AQMD decided to hold a Public Consultation meeting which was held as a joint public meeting with the CEC in the City of Anaheim on May 21, 2009. (See below for discussion on the meeting.)

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted: Font color: Red

The AQMD sent response letters to the City of Placentia and the City of Yorba Linda, both dated June 11, 2009. Both letters explained why the public hearing requests did not meet the public hearing criteria, but that a Public Consultation meeting had been held in response to the requests. The letters also explained that the evaluation of project alternatives, including alternative electricity generation technologies, are considerations under CEQA that are handled by the CEC. The AQMD, however, will consider the possibility of a combined cycle peaking power plant as part of its continued efforts in the development of latest BACT/LAER determinations.

In addition, the letter to the City of Yorba Linda explained that the AQMD does not have any control over the contents or timing of SCPPA status reports submitted to the CEC, or CEC status reports. The AQMD also does not have any control over which documents are posted on the CEC website or the timing of the postings. Further, economic issues are not air quality permitting or compliance issues that AQMD has any authority over and therefore cannot be addressed by the AQMD. Still further, the operating schedule, including the number of start-ups, is determined and proposed by the applicant. The AQMD, however, requires that the City of Anaheim comply with all applicable air quality rules and regulations under worst case or maximum emissions operating scenarios.

B&C Awnings, located at 3082 E. Miraloma Ave, Anaheim, submitted two letters, dated February 24, 2009 and March 14, 2009. The first letter expressed concerns regarding the air quality impact from the proposed project. The AQMD sent a response letter, dated March 11, 2009, which further elaborated the AQMD has conducted a thorough review and evaluation of the project for compliance with air quality rules and regulations. The second letter requested the following: (1) maximum levels of oxygen depletion, CO_2 and other pollution to be experienced during the worst case seasonal wind free conditions within a 200 yard radius, (2) copies of photovoltaic, recommendations, and non-polluting alternatives, (3) the degree to which the AQMD is prepared to compensate local business's and property owners for a further depreciation in property values, and (4)

Formatted: Subscript

applicable. The emissions calculations, the interim RECLAIM emission factor that will be used after commissioning but before CEMS certification, and the number of RTCs required, however, are based on the 2.3 ppmvd.

PM_{10}—BACT/LAER requires the use of use of PUC quality natural gas with sulfur content less than or equal to 1 grain/100 scf, but does not specify an emission limit. The warranted emission rate of 3 lb/hr corresponds to the limit of 0.060 lb/MW-hr, corrected to ISO conditions, which was required by Rule 1309.1(b)(5)(A)(iii). As explained above, Rule 1309.1 is no longer applicable.

- Catalyst Life Warranties
  The applicant provided a copy of the CO catalyst warranty and the NOx catalyst warranty. Both catalysts are guaranteed for a term of 5 years.

3. A/N 476665--Ammonia Storage Tank
The 10,000-gallon ammonia tank will provide ammonia to the four SCRs. Aqueous ammonia, 19% by weight, will be delivered by tanker truck. The maximum number of deliveries will be three per month, with each shipment varying between 6000 and 7000 gallons. The filling takes approximately 30 minutes. The filling losses will be controlled by a vapor return line to the delivery vehicle.

The tank will be a pressure vessel with a pressure relief valve set at 25 psig. Breathing losses are not expected under normal operating conditions, because the total vapor pressure of 19% aqueous ammonia at 80 deg F is 5.85 psia.

Each SCR will be equipped with an ammonia vaporization/injection skid. The aqueous ammonia will be vaporized, sprayed upstream of the SCR catalyst, and thoroughly mixing with the exhaust gas prior to entering the catalyst.

4. A/N 476666—Emergency ICE (Black Start Engine)
The ICE, Caterpillar, Model C-27, rated at 1141 BHP and fired on diesel, will serve as a black start engine. This engine is certified by the AQMD as an EPA Tier 2 engine until 12/31/2010. The engine is required to be permitted, rather than registered, because CPP is a RECLAIM/Title V facility.

The black start engine will be used only in emergency situations where grid power from the COA's 69 kV system is unavailable to start the CTGs. The black start engine will provide power to the turbine starter motors. Once the turbines are started and begin providing power to the grid, the black start engine is shut down.

The applicant initially requested 12 hours for engine testing and maintenance, with no limit for emergency operation. When explained that AQMD rules limit operation of an emergency ICE to 200 hours per year, the applicant accepted a 200 hours per year limit.

The engine will be controlled by a diesel particulate filter (dpf), which is required by LAER. The proposed CleanAIR Systems, Inc. PERMIT™ dpf, Model FDA225, is designed to control emissions from diesel engines. The proposed dpf will consist of 2 filters, each 15 inches diameter by 15 inches long. This dpf system is verified by CARB under Executive Order DE-05-002-01 to reduce emissions of diesel particulate matter consistent with a Level 3 device (greater than or equal to 85 percent reduction), with the use of low sulfur diesel with 15 ppm or lower sulfur content. As the dpf is CARB verified, a source test is not required. Thus, with the dpf, the PM emissions from the engine will be reduced from 0.15 g/bhp-hr to 0.0225 g/bhp-hr. (Although the CleanAIR Systems literature asserts VOC and CO are reduced by greater than 90%, this evaluation will not be based on those reductions because emissions reductions are CARB verified for PM only.)

The dpf, consisting of a catalyzed cordierite ceramic honeycomb with hundreds of parallel channels, is designed to reduce emissions of particulate (smoke), carbon monoxide and hydrocarbon. The catalyst on the ceramic walls oxidizes carbon monoxide into carbon dioxide, and hydrocarbons into water and carbon dioxide. The arrangement of the channels is such that the exhaust gases carrying the carbon particles are forced through the fine pores of the walls, which filter out the particles. As the carbon particles are collected on the ceramic walls, the backpressure on the engine will increase. If the temperature of the exhaust is equal to or greater than 300 °C (572 °F) for 30% of the duty cycle, the catalyst interacts with the collected particulates to burn the particulates into carbon dioxide and water vapor, which passes through the dpf. The process is called regeneration and cleans the dpf.

The CARB verification letter, dated 11/6/06, states that CleanAIR must install the HiBACK, a backpressure monitor, and indicator light on all engines fitted with a PERMIT™. The HiBACK is a microprocessor-based data logger and alarm system that records time, exhaust backpressure, and temperature while at the same time monitoring regeneration performance. The HiBACK will alert the operator if the filter is plugging, thus causing excessive backpressure on the engine. The backpressure must not exceed the specified limit set by the engine manufacturer, which is 40 inches of water for this engine.

The unit has three backpressure alarm outputs available. All outputs are programmable and pre-set **before** the unit is delivered.

Formatted: Font: Bold, No underline

Formatted: Font: Bold

- Output 1: Triggers a yellow LED. This output is set 10% below the maximum recommended backpressure and allows the user time to analyze data and service the dpf if needed.

Discussion: Condition no. E193.3 incorporates the use of this output by requiring regeneration when a yellow warning signal is received.

- Output 2: Set at the maximum recommended backpressure limit. When this level is reached a red LED is illuminated. User must shut down and service the dpf.

  Discussion: Condition E193.3 incorporates the use of this output. This condition requires the engine to be shut down and the dpf cleaned whenever the maximum backpressure is reached.

- Output 3: A voltage output that can be used to interface with the engine ECM to initiate a power de-rating mode, turn on an audible alarm, or send a signal to a remote operator.

  Discussion: Condition E193.3 incorporates the use of this output. An audible alarm will be turned on whenever the maximum backpressure is reached.

Further, CARB Executive Order DE-05-002-01 sets forth operational conditions to which the verification is subject. Compliance with each condition is discussed below.

a. The PM emission rate is 0.2 g/bhp-hr or less to the inlet of the dpf.

   Discussion: The certified PM emission rate for this engine is 0.06 g/bhp-hr.

b. The fuel is California diesel fuel with less than or equal to 15 ppm sulfur.

   Discussion: Facility condition F14.1 implements this requirement.

c. The maximum consecutive minutes at idle is 240 minutes.

   Discussion: Condition E193.3 implements this requirement.

d. The number of 10 minute idle sessions before regeneration is recommended is 12 consecutive sessions, and before regeneration is required is 24.

   Discussion: Condition E193.3 implements this requirement.

e. For filter regeneration, the engine must operate at a load level to achieve sufficient exhaust temperature (300 °C) for regeneration for 30% of the operating time or 2 hours, which is longer.

   Discussion: Condition E193.3 implements this requirement. According to Caterpillar, at 10% load, the exhaust temperature is expected to be 279 deg C.

According to the applicant, the engine will be capable of paralleling with plant bus and therefore a load can be imposed on the engine during maintenance operations. Since the stack temperature will not reach the minimum 300 deg C until the load is above approximately 15% load, the procedure will be to load the unit to 30% load (approximate exhaust temperature 390 deg C) to ensure complete catalyst regeneration. (The two hour requirement is not included in condition E193.3, because the engine is expected to be operated with the engine exhaust at or above 300 deg C 100% of the time and because it is limited to 38 minutes of operation in any one hour by condition C1.1.)

f. The number of hours of operation before cleaning or disposal of the filter is required is up to 5000 hours under normal operating conditions.

Discussion: As the cleaning to remove ash depends on the specific application and may occur before 5000 hours, condition E193.3 requires cleaning whenever the backpressure reaches the allowable maximum limit. The condition also requires a filter inspection and replacement, if necessary, after 200 hours of operation, which is equal to the allowed number of hours of operation per year. Over time, the filter may plug as it traps noncombustible ash, such as calcium, from the lube oil.

5. A/N 481185—Oil Water Separator

The oil water separator will be an underground storage tank, which will receive equipment washwater and stormwater that may be collected within several bermed areas. The equipment enclosed by the bermed areas will include the aqueous ammonia tank, four generator step-up transformers, five compressors, two service transformers and two station transformers. The valve allowing water to drain into the separator will normally be in a closed position. The water will only be allowed to drain into the separator after a visual inspection by the operator determines there is no oil sheen or other indication of a significant content of petroleum or other hazardous materials. If such materials are found to be present, a hazardous materials contractor will be contacted to come to the site and properly dispose of the captured liquid. After passing though the oil-water separator, the wastewater will flow into the sewer system.

The throughput is estimated at 55,000 gal/year, with a maximum emulsified oil content conservatively estimated as 10% by volume. The throughput is based on the average annual rainfall plus a quantity for equipment washing.

6. Rule 219 Exempt--Cooling Tower

A mechanical draft evaporative chiller cooling tower with a total of four cells will provide evaporative cooling for the inlet air to the CTGs to augment power production. The tower is exempt from permitting pursuant to Rule 219(d)(3), which exempts water cooling towers not used for evaporative cooling of process water and in which no chromium compounds are contained.

Rule 219(s)(2) provides an exception from the exemption when the risks are greater than 1 in a million. PM_{10} is released from the cooling tower through drift, which is water entrained by and carried with the air as fine droplets. The water droplets evaporate and leave the dissolved solids as PM_{10} emissions. As the analysis of the source water for the cooling tower identified trace levels of toxic inorganic particles, the applicant provided a health risk assessment for the cooling tower that indicates the risk is ~~0.029~~0.0365 in a million. As the health risk assessment has been approved by the District's modeling group, the cooling tower is exempt from permitting.

EMISSIONS CALCULATIONS

1. A/N 476651, 476656, 476659, 476661—Compression Turbine Generators Nos. 1 - 4
The CTGs will emit combustion emissions consisting of the five criteria pollutants and toxics. The four CTGs will have identical emissions.

a. Criteria Pollutants

- *Worst Case Operating Scenario*
To determine the worst case operating scenario that yields the highest controlled emissions, the applicant provided nine operating scenarios corresponding to a full range of possible turbine loads and ambient temperatures, which bound the expected normal operating range of each proposed CTG. The nine scenarios are presented in the revised Application in Table 3-2 (Revised)—1-Hour Operating Emission Rates and Stack Parameters for Individual CTG Operating Load Scenarios on pg 3-3, supplemented by the "Turbine Operating Scenarios" table in Appendix B. On April 21, 2009, the applicant submitted minor corrections to the NOx hourly emissions rates. ~~This~~ The aforementioned information is summarized in the two tables immediately below.

Formatted: No underline

Formatted: Font color: Red, Strikethrough

Table 9 - Operating Scenarios

Case No.	1	2	3	4	5	6	7	8	9
Ambient Temperature (°F)	109	109	109	59	59	59	38	38	38
Stack Diameter (ft)	11.67	11.67	11.67	11.67	11.67	11.67	11.67	11.67	11.67
Exhaust Flow (lb/hr)	1,066,554	907,936	764,619	1,080,197	963,857	832,416	1,085,651	992,555	867,866
CTG Load Level (%)	100	75	50	100	75	50	100	75	50
Evaporative Cooler	ON	ON	NONE	ON	NONE	NONE	NONE	NONE	NONE

Exhaust Temperature (°F)	841.6	858.9	832.6	838.6	785.5	754.2	836.7	759.9	710.4
Exit Velocity, ft/minute	5461.0	4710.7	3888.0	5518.1	4722.4	3975.9	5537.9	4763.1	3995.7

The operating scenarios are for three load conditions (50%, 75%, and 100%) at three ambient temperatures (38 °F, 59 °F, and 109 °F), with or without evaporative cooling of the inlet air to the turbines. For each scenario, GE provided the average hourly controlled emission rates, and stack and operating parameters for normal operation.

The five cases that resulted in the highest controlled emission rates are summarized in the table below.

Table 10 - Worst Case Operating Scenarios, Normal Operation

	1	2	4	5	7
Ambient Temperature, °F	109	109	59	59	38
CTG Load Level (%)	100	75	100	75	100
Evaporative Cooler	ON	ON	ON	NONE	NONE
Heat Consumed, (MMBTU/hr) – LHV	427.3	341.6	433.6	342.5	432.3
Heat Consumed, (MMBTU/hr) – HHV	473.6	378.6	480.6	379.6	479.2
Turbine Outlet Temperature (°F)	841.6	858.9	838.6	785.5	836.7
Average Emissions Rates, lbs/hr					
NOx at 2.3~~2~~ ppmvd BACT	~~3.99~~ 3.81	~~3.19~~ 2.94	~~4.05~~ 3.98	~~3.2~~ 2.94	~~4.03~~ 3.71
CO at 4.0 ppmvd BACT	4.19	3.34	4.24	3.34	4.23
VOC at 2.0 ppmvd BACT	1.19	0.95	1.20	0.95	1.20
PM_{10}	2.95	2.36	3.00	2.37	2.99
SO_2 short-term rate (1 grain/100 dscf)	1.34	1.07	1.36	1.07	1.35
SO_2 long-term rate (0.25 grain/100 dscf)	0.33	0.27	0.34	0.27	0.34
NH_3 at 5 ppmvd BACT	3.59	2.86	3.64	2.83	3.59

Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Underline, Font color: Red
Formatted: Underline
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red

Case 4 is the worst case operating scenario. These emissions rates are the same as BACT limits and correspond to the performance warranty levels, with the exception of CO. CO is at 4 ppmvd which is lower than the BACT limit and performance warranty level of 6 ppmvd.

- *Four Operational Modes*
  CTGs operate in four operational modes: commissioning, start-up, normal operation, and shutdown. The emissions from the four operating modes are calculated differently, but all will be based on the operating parameters for case 4.

The following table provides an explanation of the four operating modes.

Table 11--Operating Modes of the CTGs

Mode	Description
Commissioning	Commissioning is a one time event that occurs following installation of a CTG and prior to commercial operation. The facility follows a systematic approach to optimize the performance of a CTG and associated control equipment.
Start-up	Start-up occurs each time a CTG is started up. Start up emissions are higher than normal operation emissions because the control equipment has not reached optimal temperature to control to BACT levels.
Normal Operation	Normal operation occurs after the CTGs and the control equipment are working optimally. NOx is controlled to 2.3 ppmvd, CO to 4.0 ppmvd, and VOC to 2.0 ppmvd, all at 15% O_2.
Shutdown	Shutdown occurs each time a CTG is shut down. It starts at the initiation of the turbine shutdown sequence and ends with the cessation of CTG firing. Typically, during the shutdown process, the emission rates will be less than during the start-up process but may be slightly greater than during normal operation because both H_2O injection into the CTGs and NH_3 injection into the SCR reactor have ceased operation, but the catalysts remain at elevated temperatures and continue controlling for a portion of the shutdown.

- *Commissioning*
  Commissioning is performed immediately after installation of each CTG to optimize the operation of the turbomachinery and combustors, and to optimize and test the SCR/CO catalysts. The commissioning will be performed in a defined series of tests that will be conducted as follows.

- First fire the unit and then shutdown to check for leaks, etc.
- Synch and check emergency stop (e-stop)
- Additional automatic voltage regulator (AVR) commissioning
- Break-in run
- Dynamic commissioning of AVR and commission water injection and SPRINT
- Base load AVR commissioning

The NOx, CO, and VOC emission rates are higher during the commissioning period because the combustors may not be optimally tuned and the emissions are only partially abated as the water injection, CO catalyst, and SCR catalyst are installed and tested in stages. The total emissions, however, will depend on the load levels, which are typically less than 100%. The PM_{10} and SO_2 emission rates are the same as during normal operation, as these pollutants are not controlled.

Worst-case turbine commissioning emissions were estimated by assuming the control efficiency of the control systems will be zero during the commissioning tests. After consultation with GE, the PM_{10} emissions rate during commissioning was reduced from 4 lb/hr to 3 lb/hr in the revised Application.

For the second revised application, ~~T~~the applicant provided the duration and corresponding pollutant emission rates of each commissioning activity for a single CTG in Table 3-5 (Second Revised, revised on 1/05/09)—Durations and Criteria Pollutant Emissions for Commissioning of a Single CTG ~~on pg. 3-10 of the revised Application~~in a letter, dated January 6, 2009. This table corrected typographical errors in fuel use levels and VOC emissions levels, reduced the sulfur content from an erroneously high 0.82 gr/100 scf to 0.25 gr/100 scf, and adjusted the PM_{10} emissions for operating load. This table is reproduced below.

Table 12
Durations and Criteria Pollutant Emissions for Commissioning of a Single CTG

Activity	Duration (hours)	% Output at ISO	Fuel Gas Flow Rate (MMCF/hr)	Estimated Total Fuel usage (MMCF)	Exhaust Temp (°F)	Exhaust Flow Rate (acfm)	Total Pollutant Estimated Emission per Event (lbs)				
							NO_x	CO	VOC	PM_{10}	SO_2
1. First fire the unit and then shutdown to check for leaks, etc.	24	CI	0.0849~~0.0833~~	2.0371~~1.9032~~	694	199,271	200	822	27		

Formatted Table

2. Synch and check e-stop	18	SI	0.0849~~0.0833~~	1.5278~~1.4355~~	694	199,271	150	617	20	9.254	41.0
3. Additional automatic voltage regulator (AVR) commissioning	18	5%	0.1050~~0.1031~~	1.8906~~1.8065~~	726	218,499	261	329	8	11.454	1.35
4. Break-in run	12	5%	0.1050~~0.1031~~	1.2604~~1.2097~~	726	218,499	174	219	5	7.636	0.94
5. Dynamic commissioning of AVR and commission water injection and SPRINT	60	10 – 100%	0.1216 – 0.4644~~0.1194 – 0.4559~~	17.2168~~31.3871~~	713 – 843	239,475 – 513,911	1636	819	~~14~~42		
6. Base load AVR commissioning	24	100%	0.4644~~0.4559~~	11.1449~~5.1613~~	843	513,911	1023	409	30	67.272	7.632
Total emissions during commissioning	**156**			**35.0777~~42.90~~**			**3443**	**3213**	**~~99~~132**	**211.5468**	**23.9100**

Notes:
After SCR catalyst installation, the NOx emissions would be reduced by 82%, this applies to activities 2-6, thus NOx emissions presented in this table will be reduced by 82%.
After CO catalyst installation, the CO emissions would be reduced by 85%, this applies to activities 2-6, thus CO emissions presented in this table will be reduced by 85%.
CTG = combustion turbine generator
AVR = automatic voltage regulator
SCR = selective catalytic reduction
At ISO = ambient temperature of 59 °F, relative humidity of 60%, and sea level
CI = core idle mode of turbine operation, no load placed on unit
SI = synch idle mod of turbine operation, no load placed on unit

Formatted Table

Commissioning Hours--The applicant initially requested 104 hours for commissioning of each CTG, which will occur over a period not to exceed one month for each unit and up to four months for all units. To allow flexibility, the applicant subsequently requested **156 hours for the commissioning of each CTG which will occur over a period of a little over a month to 2.5 ~~1—2.5~~ months in order to comply with the monthly emission limits for VOC, PM10, and SOx in condition A63.1~~,~~. The commission for all four units may take ~~and~~ up to six months ~~for all units~~.** The 156-hour commissioning period is reflected in the table above.

For the purpose of modeling, all four CTGs were conservatively assumed to undergo worst-case commissioning testing simultaneously, although each CTG is expected to be tested individually. The results indicate that all four

CTGs may undergo testing without causing the NO_2 or CO ambient standards to be exceeded.

- *Start-up / Shutdown of CTGs*
  Start-ups begin with the initial firing and continue until each unit complies with the permitted emission concentration limits. During start-up operations, the turbine operates at elevated NOx, CO, and VOC average concentration rates due to the phased-in effectiveness of the SCR reactor and CO oxidation catalysts.

Shutdowns begin with the initiation of the turbine shutdown sequence and end with the cessation of turbine firing. Upon initiation of the shutdown process, water and ammonia injection will be discontinued. Thus, the emission rates will be less than during the start-up process but may be slightly greater than during normal operation because the catalysts remain at elevated temperatures.

Startup/Shutdown Cycles, Annual and Monthly--The applicant initially requested 514 startup/shutdown cycles per year among all four turbines, with an average of 128.5 cycles per year. As the New Source Review (NSR) rules will not allow bubbling of emissions among turbines, the applicant agreed to 129 startup/shutdown cycles per **year** for each turbine, for both the commissioning year and subsequent normal operating years. **Subsequently, the second revised Application requested a change to 240 startup/shutdown cycles per *year* for each turbine for all years.** In addition, a monthly emissions limit is required pursuant to Rule 1313(g) to establish a basis for calculating offset requirements. The applicant initially requested 124 startup/shutdown cycles per month among all four turbines, but agreed to a maximum of 31 startup/shutdown cycles per **month** for each turbine for all years. **Subsequently, the second revised Application requested a change to 20 startup/shutdown cycles per *month* for each turbine for all years.**

Formatted: Underline, Font color: Red
Formatted: Font: Not Bold
Formatted: No underline
Formatted: Font: Not Bold
Formatted: Font: Italic, No underline
Formatted: Font: Not Bold
Formatted: No underline
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Font: Italic, No underline

Startup Duration—The applicant initially requested 20 minutes per start-up but subsequently increased the duration to **35 minutes per start-up event.** The applicant initially requested the maximum hourly turbine startup emissions to accommodate a full start-up sequence of 20 minutes, later increased to 35 minutes, with the remainder of the hour consisting of normal operations. To allow flexibility, the applicant subsequently requested an increase in the maximum hourly turbine startup emissions to accommodate a full startup sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence.

Shutdown Duration—The applicant initially requested 8 minutes per shutdown but subsequently increased the duration to **10 minutes per shutdown event**.

Startup/Shutdown Emissions—The applicant provided two tables—Revised 72-Minute Sequence of Normal Startup and Emission Control with Turbine Trip and Restart, and Pollutant Emissions for a 10-Minute Shutdown Sequence for Individual Turbine--showing the minute-by-minute emissions for startups and shutdowns, respectively, in Appendix E of the revised Application. The relevant information is summarized in the two tables imm~~m~~ediately below.

Table 13
Revised Turbine Startup Sequence for a Normal 35–Minute Startup Event, Turbine Trip, Purge for 5 Minutes, then Restart

			Stack emissions per Turbine											
Time	CT	SCR	NOx		CO		ROG		PM10		SOx @ 0.25 gr		SOx @ 1 gr	
(min)	Δ time	Δ time	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total
0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	1		18.00	0.30	0.22	0.4	2.50	0.04	0.63	0.01	0.07	0.00	0.28	0.00
2			18.00	0.60	0.22	0.7	2.50	0.08	0.63	0.02	0.07	0.00	0.28	0.01
4			18.00	1.20	0.22	1.5	2.50	0.17	0.63	0.04	0.07	0.00	0.28	0.02
6	5		18.00	1.80	10.0	1.8	2.25	0.24	0.63	0.06	0.07	0.01	0.28	0.03
8	2		18.00	2.40	10.0	2.1	2.25	0.32	0.63	0.08	0.07	0.01	0.28	0.04
10			50.00	4.07	4.5	2.3	0.36	0.33	1.16	0.12	0.13	0.01	0.51	0.05
12		12	26.00	4.93	6.8	2.5	0.90	0.36	1.69	0.18	0.19	0.02	0.74	0.08
14			33.00	6.03	3.1	2.6	0.90	0.39	2.22	0.25	0.24	0.03	0.97	0.11
15		3	38.00	6.67	3.5	2.7	0.90	0.40	2.48	0.29	0.27	0.03	1.09	0.13
16			15.49	6.92	3.7	2.7	0.99	0.42	2.75	0.34	0.30	0.04	1.20	0.15
17	9		16.63	7.20	4.2	2.8	1.13	0.44	3.01	0.39	0.33	0.04	1.32	0.17
18			15.93	7.47	4.2	2.9	1.17	0.46	3.01	0.44	0.33	0.05	1.32	0.19
20			14.52	7.95	4.2	3.0	1.17	0.50	3.01	0.54	0.33	0.06	1.32	0.24
22			13.11	8.39	4.2	3.2	1.17	0.54	3.01	0.64	0.33	0.07	1.32	0.28
24			11.71	8.78	4.2	3.3	1.17	0.58	3.01	0.74	0.33	0.08	1.32	0.33
26			10.30	9.12	4.2	3.4	1.17	0.61	3.01	0.84	0.33	0.09	1.32	0.37
28			8.90	9.42	4.2	3.6	1.17	0.65	3.01	0.94	0.33	0.10	1.32	0.41
30			7.49	9.67	4.2	3.7	1.17	0.69	3.01	1.04	0.33	0.11	1.32	0.46
32			6.09	9.87	4.2	3.8	1.17	0.73	3.01	1.14	0.33	0.13	1.32	0.50
34			4.68	10.03	4.2	4.0	1.17	0.77	3.01	1.24	0.33	0.14	1.32	0.55

			Stack emissions per Turbine											
Time	CT	SCR	NOx		CO		ROG		PM10		SOx @ 0.25 gr		SOx @ 1 gr	
(min)	Δ time	Δ time	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total
35		18	3.98	10.09	4.2	4.1	1.17	0.79	3.01	1.29	0.33	0.14	1.32	0.57
36			0.00	10.09	0	4.1	0.00	0.79	0.00	1.29	0.00	0.14	0.00	0.57
38			0.00	10.09	0	4.1	0.00	0.79	0.00	1.29	0.00	0.14	0.00	0.57
40	5		0.00	10.09	0	4.1	0.00	0.79	0.00	1.29	0.00	0.14	0.00	0.57
40	0		0.00	10.09	0	4.1	0.00	0.79	0.00	1.29	0.00	0.14	0.00	0.57
41	1	0	18.00	10.39	22	4.4	2.50	0.83	0.63	1.30	0.07	0.14	0.28	0.57
42			18.00	10.69	10.0	4.6	2.33	0.87	0.63	1.31	0.07	0.14	0.28	0.58
43		2	6.80	10.81	10.0	4.8	2.33	0.91	0.63	1.32	0.07	0.15	0.28	0.58
44			6.80	10.92	10.0	4.9	2.33	0.95	0.63	1.34	0.07	0.15	0.28	0.59
46	5		6.80	11.15	10.0	5.3	2.33	1.03	0.63	1.36	0.07	0.15	0.28	0.60
48	2		6.80	11.37	10.0	5.6	2.33	1.10	0.63	1.38	0.07	0.15	0.28	0.60
50			18.90	12.00	2.2	5.7	0.45	1.12	1.16	1.42	0.13	0.16	0.51	0.62
52			9.83	12.33	3.3	5.8	0.90	1.15	1.69	1.47	0.19	0.16	0.74	0.65
54			12.47	12.75	3.1	5.9	0.90	1.18	2.22	1.55	0.24	0.17	0.97	0.68
56			15.49	13.26	3.7	6.0	0.99	1.21	2.75	1.64	0.30	0.18	1.20	0.72
57	9		16.63	13.54	4.2	6.1	1.13	1.23	3.01	1.69	0.33	0.19	1.32	0.74
58			15.78	13.80	4.2	6.1	1.17	1.25	3.01	1.74	0.33	0.19	1.32	0.76
60			14.10	14.27	4.2	6.3	1.17	1.29	3.01	1.84	0.33	0.20	1.32	0.81
72		15	3.98	15.07	4.18	7.12	1.17	1.52	3.01	2.44	0.33	0.27	1.32	1.07

Table 14A– Revised Turbine Shut-Down Sequence for a 10–Minute Shutdown

Stack emissions per turbine												
Time	NOx		CO		ROG		PM10		SOx @ .25gr		SOx @ 1gr	
(min)	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total	(#/hr)	# total
0	3.98	0.00	4.24	0.00	1.17	0.00	3.01	0.00	0.33	0.00	1.32	0.02
1	6.53	0.11	2.86	0.05	0.99	0.02	2.52	0.04	0.28	0.00	1.11	0.04
2	5.26	0.20	3.30	0.10	0.81	0.03	2.03	0.08	0.22	0.01	0.89	0.06
3	4.17	0.27	2.42	0.14	0.63	0.04	1.58	0.10	0.17	0.01	0.69	0.07
4	2.90	0.31	1.56	0.17	0.45	0.05	1.14	0.12	0.13	0.01	0.50	0.08
5	6.35	0.42	3.08	0.22	2.25	0.09	0.63	0.13	0.07	0.01	0.28	0.08
6	3.27	0.47	4.84	0.30	2.25	0.12	0.63	0.14	0.07	0.02	0.28	0.08
7	3.27	0.53	4.84	0.38	2.25	0.16	0.63	0.15	0.07	0.02	0.28	0.09
8	3.27	0.58	4.84	0.46	2.25	0.20	0.63	0.16	0.07	0.02	0.28	0.09
9	3.27	0.64	4.84	0.54	2.25	0.24	0.63	0.17	0.07	0.02	0.28	0.10
10	3.27	0.69	4.84	0.62	2.25	0.27	0.63	0.18	0.07	0.02	0.28	0.10

Startup and Shut Down Conditions--Condition nos. A99.1, A99.2, and A99.3 limit each startup to 35 minutes, each shutdown to 10 minutes, and the number of startups and shutdowns to ~~129~~ 240 per year. The conditions also set the emissions limits for NOx, CO, and ROG, respectively, for an hour which includes a full start-up sequence of 35 minutes, followed immediately by a turbine trip, a five minute purge period during which no fuel is burned, and the first 20 minutes of a restart sequence. The limits are from Table 13 above for cumulative emissions at 60 minutes. (The air quality modeling for the 1-hr averaging time for the start-up scenarios reflect these hourly emission rates for NOx (14.27 lb/hr) and CO (6.3 lb/hr).) These conditions also set the emissions limits for NOx, CO, and ROG, respectively for an hour which includes a shutdown. The limits are from Table 14B below.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Table 14B—Emissions for Hour that Includes a Shutdown

Duration	10 minutes Shutdown Emissions lb/event	50 minutes Normal Operating Hourly Emissions	Hourly Emissions for Hour with a Shutdown and 50 Minutes of Normal Operation
NOx	0.69	4.05 x 50/60 = 3.375	4.07
CO	0.62	4.24 x 50/60 = 3.53	4.15
VOC	0.27	1.2 x 50/60 = 1.0	1.27
PM_{10}	0.18	3.0 x 50/60 = 2.5	2.68
SO_2	0.02	0.34 x 50/60 = 0.28	0.3

- *Normal Operation*
  The emissions during normal operations are assumed to be fully controlled to Best Available Control Technology (BACT) levels, and exclude emissions due to commissioning, start up and shutdown periods, which are not subject to BACT levels.

Operating Hours, Annual and Monthly--The applicant initially requested 4006 hours of normal operation per year among all four turbines, **excluding** start-up and shut-down time. As the NSR rules will not allow bubbling of emissions among turbines, the applicant agreed to 1001.5 hrs per **year** of normal operation for each turbine. The revised Application reduced the annual operating hours for each turbine to 446 hours for the commissioning year and to 602 hours for subsequent normal operating years. (The number of annual operating hours proposed for the commissioning year is lower than that for the subsequent normal operating years to ensure that the facility-wide PM_{10} emissions remain at slightly below 4 TPY for all years.)

Formatted: Font: Bold, No underline

Formatted: Font: Bold, No underline

Formatted: Font: Not Bold

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Subsequently, the second revised Application revised the annual operating hours for each turbine to 1080 hours per year for a normal operating year, but did not request a limit for the commissioning year. For the commissioning year, the actual number of normal operating hours will depend on the actual duration of the commissioning because the total emissions per month from commissioning and/or normal operations will be limited by condition A63.1. The maximum number of normal operating hours will be less than 990 hours, based on 11 months of normal operations with a maximum of 90 hours per month. The reason is that, for VOC only, the total commissioning emissions of 132 pounds will be higher than the limit of 129 pounds set by condition A63.1 for a normal operating month. Thus, commissioning activities, if a full 156 hours is required, will be required to carry over to the next month (one day) once the VOC emissions reach the monthly limit of 129 lb/month.

A monthly emissions limit is required pursuant to Rule 1313(g) to establish a basis for calculating offset requirements. The applicant initially requested 279 hrs per **month** of normal operation for each turbine. **Subsequently, the second revised Application requested 90 hrs per *month* of normal operation for each turbine.**

Formatted: Font: Bold, No underline

Formatted: Font: Italic, No underline

- *Overview of Emissions Calculations*
  The emissions calculations for a power plant are complex because the emissions from the four operating modes must be included. The following sections will discuss hourly emissions, startup and shutdown emissions, daily emissions, monthly emissions, and annual emissions, as well as emission factors and permit condition limits. Finally, offset requirements for peaker plants and the calculation of NSR entries will be discussed.

  - *Hourly Emission Rates/Emission Factors*
    Commissioning
    As indicated in Table 12 above, the hourly emissions rate will vary depending on the stage of the commissioning and is not required to be determined.

    The commissioning period emission factors, however, are required for condition no. A63.1 ~~and A63.2~~ for VOC, PM10, and SOX, and condition no. A99.4 for NOx. For each pollutant, the emission factor is the total emissions for the commissioning period divided by the total fuel usage for the commissioning period, both of which are from Table 12 above. The table below shows the derivation of the emissions factors.

Table 15—Commissioning Emission Factors

Pollutant	Total Commissioning Emissions, lb	Total Commissioning Fuel Usage, mmcf	Emission Factor, lb/mmcf
NOx	3443	35.077~~42.9~~	~~80.26~~98.16
VOC	~~99~~132	35.077~~42.9~~	~~2.31~~3.76
PM_{10}	~~468~~211.5	35.077~~42.9~~	~~10.91~~6.03
SOx	~~100~~23.9	35.077~~42.9~~	~~2.33~~0.68

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Normal Operation

The maximum controlled hourly emission rates for normal operations that will be used to calculate turbine emissions are summarized in the table below. The emission rates are taken from Table 10 above for Case 4.

Table 16 – Maximum Hourly Emissions, Normal Operations, per CTG

Pollutants	Emission Rate, lb/hr
NO_x at 2.3 ppmvd	~~4.05~~ 3.98
CO at 4.0 ppmvd	4.24
VOC at 2.0 ppmvd	1.20
PM_{10}	3.00
SO_2 at 0.25 grain/100 dscf	0.34
NH_3 at 5 ppmvd	3.64

Formatted: Font color: Red, Strikethrough

Formatted: Underline, Font color: Red

For emissions calculations, the emissions rate for SO2 at 0.25 gr/100 dscf is used because that is the average natural gas sulfur content. Confirmation of this concentration limit is ensured by condition B61.1. The 1 gr/100 dscf is the maximum sulfur content that Southern California Gas Co. may legally provide.

- *Startup and Shutdown Emissions*

  The emissions per startup and shutdown events that will be used to calculate turbine emissions are summarized below in the table below.

Table 17 – Startup and Shutdown Emissions, per CTG

Pollutants	Startup, lbs/event	Shutdown, lbs/event
NOx	10.09	0.69
CO	4.10	0.62
VOC	0.79	0.27
PM_{10}	1.29	0.18
SOx at 0.25 gr/100 dscf	0.14	0.02

For startups, the lbs/event are taken from Table 13 above for cumulative emissions at 35 minutes, which is the duration of a startup.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

For shutdowns, the lbs/event are taken from Table 14A above for cumulative emissions at 10 minutes, which is the duration of a shutdown.

- *Daily Emissions per Turbine*
  The maximum daily emissions for normal operations are calculated to determine whether public notice is required under Rule 212(c)(2). ~~Permit~~ ~~c~~Condition A63.1~~s~~, however, will limit ~~annual and~~ monthly emissions, not daily emissions. The monthly emissions limits establish a basis for calculating offset requirements.

  Commissioning Month
  The maximum daily emissions for the commissioning month are not necessary to be determined.

  Normal Operating Month
  The maximum controlled daily emissions for normal operations are shown in the table below. These emissions are based on 22.5 hours normal operation and 2 startups (35-minute events) and 2 shutdowns (10-minute events). The normal operation emission rates are from Table 16, and the startup and shutdown emissions per event are from Table 17.

Table 18—Maximum Daily Emissions, per CTG

Pollutants	No. of Normal Operating Hrs	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shutdowns	lb/shutdown	Maximum Daily Emissions lb/day
NOx	22.5	~~4.05~~ 3.98	2	10.09	2	0.69	~~112.69~~ **111.11**
CO	22.5	4.24	2	4.10	2	0.62	**104.84**
VOC	22.5	1.2	2	0.79	2	0.27	**29.12**
PM_{10}	22.5	3.00	2	1.29	2	0.18	**70.44**
SOx	22.5	0.34	2	0.14	2	0.02	**7.97**

Formatted: Font color: Red, Strikethrough
Formatted: Underline, Font color: Red
Formatted: Font color: Red, Strikethrough
Formatted: Underline, Font color: Red

Maximum Daily Emissions, lb/day = (no. normal operating hours) (normal emission rate) + (no. startups) (lb/startup) + (no. shutdowns) (lb/shutdown)

- *Monthly Emissions per Turbine*
  Commissioning Month

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

~~The maximum commissioning month emissions are shown in the table below. The values are from Table 12, above, under "Total emissions during commissioning," totalized to 156 hours. The commissioning period will take 1 – 2.5 months per turbine, but the maximum monthly emissions will result when the commissioning is assumed to take one month.~~ The second revised Application requested that the maximum VOC, SOx, and PM_{10} in any one month during the commissioning period not exceed the maximum emissions during a normal operating month. The maximum emissions during a normal operating month are shown in Table 20, below, and will establish offset requirements. These maximum monthly emissions are reflected in condition A63.1 as 129 lb/month VOC, 299 lb/month PM_{10}, and 34 lb/month SOx. The total commissioning emissions are found in Table 12, above, under "Total emissions during commissioning," which is totalized to 156 hours. The total commissioning emissions are 132 lb VOC, 211.5 lb PM_{10}, and 23.9 lb SOx. The total commissioning emissions will be higher than the maximum normal operating month emissions for VOC, but not for SOx and PM_{10}. Thus, commissioning activities will be required to carry over to the next month (one day) once the VOC emissions reach the monthly limit of 129 lb/month.

The maximum monthly emissions during the commissioning period are shown in Table 19, below. These emissions are calculated by adjusting the total commissioning emissions from Table 12 such that the VOC emissions meet the 129 pounds limit.

Table 19 –Maximum Monthly Emissions, Commissioning, per CTG

Pollutants	Commissioning Emissions, lbs/month
NO_x	3443 x 129/132 = 3364.75~~3443~~
CO	3213 x 129/132 = 3139.98~~3213~~
VOC	132 x 129/132 = 129~~99~~
PM_{10}	211.5 x 129/132 = 206.69~~468~~
SO_x	23.9 x 129/132 = 23.36~~100~~

Normal Operating Month
The maximum normal operating month emissions are shown in the table below.

Table 20—Maximum Monthly Emissions, Normal Operations, per CTG

Formatted: Indent: Left: 0"

Pollutants	No. of Normal Operating	Normal Operation Emission	No. of Startups	lb/startup	No. of Shutdowns	lb/shutdown	Maximum Monthly Emissions

	Hrs	**Rate, lb/hr**					**lb/month**
NOx	90~~279~~	~~4.05~~ 3.98	20~~31~~	10.09	20~~31~~	0.69	~~580.10~~ 573.80~~1464.13~~
CO	90~~279~~	4.24	20~~31~~	4.10	20~~31~~	0.62	476.00~~1329.08~~
VOC	90~~279~~	1.2	20~~31~~	0.79	20~~31~~	0.27	129.20~~367.66~~
PM_{10}	90~~279~~	3.00	20~~31~~	1.29	20~~31~~	0.18	299.40~~882.57~~
SOx	90~~279~~	0.34	20~~31~~	0.14	20~~31~~	0.02	33.80~~99.82~~

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red, Strikethrough

Formatted: Underline, Font color: Red

Formatted: Font color: Red, Strikethrough

Maximum Monthly Emissions, lb/day = (no. normal operating hours) (normal emission rate) + (no. startups) (lb/startup) + (no. shutdowns) (lb/shutdown)

These emissions are based on the maximum of ~~279~~90 hours normal operation and ~~31~~20 startups and shutdowns per CTG requested by the applicant. This translates to 105 hr max/month.

(The public notice will include a table of maximum monthly emissions. For ammonia, the maximum monthly emissions are 382.2 lb/month, conservatively assuming that the ammonia is flowing at a constant rate of 3.64 lb/hr throughout the entire start-up and shutdown events. [Calculated as (3.64 lb/hr) (105 hr max/month) = 382.2 lb/month])

Permit Conditions—Monthly Emissions Limits

Condition A63.1 specifies the monthly emissions limits for VOC, PM_{10}, and SOx because Rule 1313(g) requires a monthly emission limit for non-attainment pollutants to establish a basis for calculating offset requirements. A monthly limit is not required for CO because it is in attainment and not a precursor to any nonattainment pollutant. A monthly limit is not required for NOx because the number of RECLAIM RTCs required are determined on an annual basis.

The maximum monthly emissions limits will be based on a normal operating month~~, which are higher than the maximum monthly emissions for the commissioning period~~ pursuant to the second revised Application. Since the commissioning period may take up to 2.5 months, there may be a month during which both commissioning and normal operations take place. The applicant has stated that the maximum normal month emissions, based on ~~279~~90 hours and ~~31~~20 startups and shutdowns, will be sufficient to cover a month in which commissioning and normal operations overlap. Thus condition A63.1 will limit VOC emissions to ~~368~~129 lb/month, PM_{10} to ~~883~~299 lb/month, and SO_x to ~~100~~34 lb/month.

- *Annual Emissions per Turbine*

Commissioning Year

The maximum commissioning year emissions can be calculated by adding the maximum commissioning month emissions from Table 19 to emissions for eleven months of normal operations from Table 21, as enforced by condition A63.1. The reason is that the commissioning can be accomplished in one month with a carryover to the next month (one day) and still meet the monthly limits for all months. -(Table 22 has been removed because it has been consolidated into Table 21.) ~~are the sum of: (1) commissioning period emissions and (2) normal operating emissions for the remainder of the year based on 446 hours of full load operation and 129 startups and shutdowns.~~

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

~~The commissioning period emissions are from Table 19 above. The normal operating emissions for the remainder of the commissioning year are calculated and shown in the table below.~~

~~Table 21 Normal Operating Emissions (Not Including Commissioning Emissions), Commissioning Year~~

~~Pollutants~~	~~No. of Normal Operating Hrs~~	~~Normal Operation Emission Rate, lb/hr~~	~~No. of Startups~~	
~~NOx~~	446	~~4.05~~	~~129~~	
~~CO~~	446	~~4.24~~	~~129~~	
~~VOC~~	446	~~1.2~~	~~129~~	
~~PM_{10}~~	446	~~3.00~~	~~129~~	
~~SOx~~	446	~~0.34~~	~~129~~	

~~The maximum annual emissions comprising of commissioning period emissions and normal operating emissions are calculated and shown in the table below.~~

~~Table 22 Maximum Total Annual Emissions, Commissioning Year~~

~~Pollutant~~	~~Commissioning Period, lb/yr~~	~~Normal Operating Annual Emissions, lb/yr~~	~~Total Commissioning Year Emissions, lbs/yr~~
~~NOx~~	~~3443~~	~~3196.92~~	~~6639.92 (3.32 tpy)~~
~~CO~~	~~3213~~	~~2499.92~~	~~5712.92 (2.86~~

			~~tpy)~~
~~VOC~~	~~99~~	~~671.94~~	~~770.94 (0.39 tpy)~~
~~PM_{10}~~	~~468~~	~~1527.63~~	~~1995.63 (1.0 tpy)~~
~~SOx~~	~~100~~	~~172.28~~	~~272.28 (0.14 tpy)~~

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Table 21 –Maximum Annual Emissions, Commissioning Year, per CTG

Pollutants	Commissioning Year Emissions, lb/yr
NO_x	3364.75 lb/commissioning month + (11 months) (~~580.1~~ 573.80 lb/month) = ~~9745.85~~ 9676.55 lb/yr (~~4.87~~ 4.84 tpy)
CO	3139.98 lb/commissioning month + (11 months) (476 lb/month) = 8375.98 lb/yr (4.19 tpy)
VOC	129 lb/commissioning month + (11 months) (129 lb/month) = 1548 lb/yr (0.77 tpy)
PM_{10}	206.69 lb/commissioning month + (11 months) (299 lb/month) = 3495.69 lb/yr (1.75 tpy)
SO_x	23.36 lb/commissioning month + (11 months) (34 lb/month) = 397.36 lb/yr (0.20 tpy)

Formatted Table
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red

Normal Operating Year
The maximum normal operating year emissions are shown in the table below. The emissions are ~~based on a maximum of 602 hours normal operation and 129 startups (35 min/startup) and shutdowns (10 min/shutdown), which total to 698.75 hrs/yr.~~ calculated by multiplying the maximum monthly emissions from Table 20~~-~~, as enforced by condition A63.1, by 12 months.

Table 23 –Maximum Annual Emissions, Normal Operating Year, with Emissions Factors, per CTG

Pollutants	Maximum Monthly Emissions, lb/month	Maximum Annual Emissions, lb/yr	Emission Factors, lb/mmcf
NOx	~~580~~ 573.80	~~6960~~ 6885.6 lb/yr (~~3.48~~ 3.44 tpy)	~~11.65~~ 11.53
CO	476	5712 lb/yr (2.86 tpy)	9.57
VOC	129	1548 lb/yr (0.77 tpy)	2.59
PM_{10}	299	3588 lb/yr (1.79 tpy)	6.03
SOx	34	408 lb/yr (0.20 tpy)	0.68

Formatted: Font color: Red, Strikethrough
Formatted: Underline, Font color: Red
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red
Formatted: Font color: Red
Formatted: Font color: Red, Strikethrough

The table above also shows the normal operating emission factors, which are required for condition nos. A63.1 ~~and A63.2~~ for VOC, PM_{10}, and SO_X, and condition no. A99.5 for NOx.

Emission Factor, lbs/mmcf = (lbs/yr) x (yr/~~698.75~~ 1260 hrs) x (2.11 hr/mmcf)

The 2.11 hr/mmcf is calculated as 913 Btu/scf (LHV) / 433.6 MMBtu/hr (LHV), with both values provided by the applicant.

Permit Conditions—Annual Emissions Limits
For NOx, condition I296.1 sets forth the RTCs required for the commissioning year and subsequent normal operating years. From Table 21 above, the RTCs required for the commissioning year are ~~9746~~ 9677 lb/yr. From Table 23 above, the RTCs required for subsequent normal operating years are ~~6960~~ 6886 lb/yr.

For VOC, PM_{10}, and SOx, a permit condition to explicitly limit annual emissions is not necessary. The annual emissions limits are the monthly emissions limits set forth in condition A63.1 multiplied by twelve months. ~~Condition A63.2 specifies the annual emissions limits for VOC, PM10, and SOx to ensure that the emissions from these pollutants are less than 4 tpy, thereby not requiring offsets pursuant to the Rule 1304(d)(1)(A) exemption. An annual limit is not required for CO because it is in attainment and not a precursor to any nonattainment pollutant, and because the emissions are not close to the PSD threshold of 250 tpy. An annual limit is not required for NOx because condition no. I296.1 specifies the number of RTCs required for the commissioning year (6640 lbs NOx) and subsequent normal operating years (3829 lbs NOx).~~

~~The annual emissions limit is based on the higher of the commissioning year emissions or the normal operating year emissions. Thus, condition A63.2 will limit VOC emissions to 859 lb/yr, PM10 to 1996 lb/yr, and SOx to 272 lb/yr. EPA requires that the annual emission limit shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12 month period beginning on the first day of each calendar month.~~

- *Offset Requirements/NSR Entries*
  The offset requirements for the different pollutants are described below.

VOC, SOx, and PM_{10}

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

Formatted: No underline

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

Rule 1303(b)(2) requires a net emission increase in emissions of any nonattainment air contaminant from a new source to be offset unless exempt from offset requirements pursuant to Rule 1304. "Source" is defined by Rule 1302(ao) to mean "any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air contaminant. This includes any permit unit at any non-RECLAIM facility and any device at a RECLAIM facility. Rule 1304(d)(1)(A) provides, in part, that any new facility that has a potential to emit less than 4 tons per year for VOC, SOx, or PM_{10} shall be exempt from offsets for those pollutants that are under the threshold. As discussed above, Rule 1304 exemptions, however, are not currently available because of the recent court decision. Therefore, CPP will be required to provide emission reduction credits (ERCs) for all increases in emissions from permitted equipment, based on a 30-day average, for these pollutants. ~~Since peaker power plants operate primarily during the summer, the District interpreted this provision to mean that offsets are not required for VOC, SOx, or PM10, if the maximum annual facility emissions for permitted equipment, calculated by summing the maximum emissions for the twelve months in a year, are less than 4 tpy for those pollutants. This method for deriving annual emissions is different from the normal NSR calculation method where the annual emissions is the maximum monthly emissions for any one month, calculated as the 30-day average, multiplied by twelve months. For peaker power plants only, the emissions for a pollutant is annualized over twelve months when the emissions are less than 4 TPY.~~

~~If the total project emissions for any of these pollutants exceed the 4 TPY threshold, however,~~

~~t~~The amount of offsets required for each ~~such~~ pollutant is determined using the 30-day average. The 30-day average is based on the higher of the emissions for a commissioning month or a normal operating month. According to the second revised Application, the emissions for the commissioning month now will be no higher than the emissions for a normal operating month. The offset ratio for emission reduction credits (ERCs) is 1.2-to-1. The applicant is required to hold the required amount of ERCs before the Permits to Construct may be issued. (As discussed above, ~~P~~priority reserve credits (PRCs) are not available because of the court decision on Rule 1309.1.)

~~Table 26 below sets forth the maximum annual facility emissions for the commissioning year, and Table 27 below sets forth the maximum annual facility emissions for a normal operating year. Both tables confirm that the maximum annual facility emissions for VOC, PM10 and SOx will be less than~~

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"
Formatted: Underline, Font color: Red
Formatted: Underline
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Underline

~~4 tpy for both the commissioning year and a normal operating year. **Therefore, no offsets will be required for VOC, PM_{10}, and SOx.** The emissions calculations will be performed accordingly.~~

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

CO
Since CO is an attainment pollutant and is not a precursor to any nonattainment pollutant, **offsets are not required**.

NOx
The facility has opted into RECLAIM. Rule 2205(b)(2) requires a new facility to sufficient RTCs to offset the total facility emissions for the first year of operation, at a 1-to-1 ratio. Specifically, equipment shall not be operated unless the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. Further, the equipment shall not be operated unless at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase. Thus, the emissions during the initial commissioning year and the emissions during subsequent normal operating years are required to be calculated to determine the number of RTCs required.

The NSR entries are calculated below.

- *Operating Schedule*
  Operating Schedule: 52 wks/yr, 7 days/wk, 24 hrs/day
  (Actual operating schedule will depend on the need for operation.)

  The maximum monthly emissions for each CTG are from Table 20, above.

The emissions calculations are for *each* CTG--

- *NO_x*
  Actual controlled = 2.3~~2~~ ppm = ~~4.05~~ 3.98 lb/hr
  Actual uncontrolled = 25 ppm with water injection = 43.64 lb/hr
  (provided by Express Integrated Technologies)

  To calculate control efficiency:
  Control efficiency = [(43.64 – ~~4.05~~ 3.98)/43.64] x 100%
  = ~~90.72%~~ 90.88%

  To calculate R2:
  Lb/day = [~~580.1~~ 573.80 lb/month (see Table 20)] (month/30 days)
  = ~~19.34~~ 19.13 lb/day

Formatted: Indent: Left: 1.5"
Formatted: Font: Italic
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Font: 18 pt
Formatted: Font color: Red, Strikethrough
Formatted: Indent: Left: 2.5", First line: 0.5"
Formatted: Font color: Red, Strikethrough
Formatted: Underline, Font color: Red
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red
Formatted: Font color: Red, Strikethrough
Formatted: Underline

Lb/hr = (~~19.34~~ 19.13 lb/day) (day/24 hr) = ~~0.81~~ 0.80 lb/hr

30-DA = (~~0.81~~ 0.80 lb/hr) (24 hr/day) = ~~19.44~~ 19.2 lb/day (from NSR Data Summary Sheet)

To calculate R1:

Lb/day, uncontrolled = (~~19.34~~ 19.13 lb/day) / (1-~~0.9072~~ 0.9088) = ~~208.41~~ 209.76 lb/day

Lb/hr, uncontrolled = (~~208.41~~ 209.76 lb/day) (day/24 hr) = ~~8.68~~ 8.74 lb/hr

Number of RTCs required:

Condition I296.1 sets forth the RTCs required for the commissioning year and subsequent normal operating years.

From Table 21 above, the RTCs required for the commissioning year are ~~9746~~ 9677 lb/yr.

From Table 23 above, the RTCs required for subsequent normal operating years are ~~6960~~ 6886 lb/yr.

~~To calculate R2 based on annualized operating schedule:~~

~~Lb/day, controlled = [6639.92 lb/yr (commissioning yr)] [yr/52 wk] [wk/7 days] = 18.24 lb/day~~

~~Lb/hr, controlled = [18.24 lb/day] [day/24 hr] = 0.76 lb/hr~~

~~30-DA = 18 lb/day~~

~~To calculate R1:~~

~~Lb/day, uncontrolled = (18.24 lb/day) / (1- 0.9072) = 196.55 lb/day~~

~~Lb/hr, uncontrolled = (196.55 lb/day) (day/24 hrs) = 8.19 lb/hr~~

- *CO*

Actual controlled = 4.0 ppm = 4.24 lb/hr

Actual uncontrolled = 53 ppm (provided by Express Integrated Technologies) = 56.18 lb/hr

To calculate control efficiency:

Control efficiency = [(56.18 – 4.24)/56.18] x 100% = 92.45%

To calculate R2:

Lb/day = [476 lb/month (Table 20)] (month/30 days) = 15.87 lb/day

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Underline, Font color: Red
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red
Formatted: No underline
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Red, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Underline
Formatted: Font color: Orange, Strikethrough
Formatted: Underline
Formatted: Font color: Orange, Strikethrough
Formatted: Underline, Font color: Orange
Formatted: Font color: Orange, Strikethrough
Formatted: Underline
Formatted: Font color: Orange, Strikethrough

Lb/hr = (15.87 lb/day) (day/24 hr) = 0.66 lb/hr

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

30-DA = (0.66 lb/hr) (24 hr/day) = 15.84 lb/day (from NSR Data Summary Sheet)

To calculate R1:
Lb/day, uncontrolled = (15.87 lb/day) /(1-0.9245) = 210.20 lb/day
Lb/hr, uncontrolled = (210.20 lb/day) (day/24 hr) = 8.76 lb/hr

ERCs required: None because CO is in attainment.
~~To calculate R2 based on annualized operating schedule:~~
~~Lb/day, controlled = [5707.76 lb/yr (commissioning yr)] [yr/52 wk] [wk/7 days] = 15.68 lb/day~~
~~Lb/hr, controlled = [15.68 lb/day] [day/24 hr] = 0.65 lb/hr~~
~~30-DA = 16 lb/day~~

~~To calculate R1:~~
~~Lb/day, uncontrolled = (15.68 lb/day) / (1- 0.9245) = 207.68 lb/day~~
~~Lb/hr, uncontrolled = (207.68 lb/day) (day/24 hrs) = 8.65 lb/hr~~

- *ROG*

Actual controlled = 2.0 ppm = 1.2 lb/hr
Actual uncontrolled = 3 ppm (provided by Express Integrated Technologies) = 1.8 lb/hr

To calculate control efficiency:
Control efficiency = [(1.8 – 1.2)/1.8] x 100% = 33.33%

To calculate R2:
Lb/day = [129.2 lb/month (Table 20)] (month/30 days) = 4.31 lb/day

Lb/hr = (4.31 lb/day) (day/24 hr) = 0.18 lb/hr

30-DA = (0.18 lb/hr) (24 hr/day) = 4.3~~2~~1 lb/day (from NSR Data Summary Sheet)

To calculate R1:
Lb/day, uncontrolled = (4.31 lb/day) /(1-0.3333) = 6.46 lb/day
Lb/hr, uncontrolled = (6.46 lb/day) (day/24 hr) = 0.27 lb/hr

~~ERCs required = (4.32 lb/day) (1.2) = 5.18 lb/day → 5 lb/day~~

Formatted: Strikethrough

Note: The emissions rate, e.g. 4.321 lb/day is no longer rounded before the 1.2 offset ratio is applied, pursuant to a clarification in District policy.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

~~To calculate R2 based on annualized operating schedule:~~

~~Lb/day, controlled = [859.14 lb/yr (normal operating yr)] [yr/52 wk] [wk/7 days] = 2.36 lb/day~~

~~Lb/hr, controlled = [2.36 lb/day] [day/24 hr] = 0.10 lb/hr~~

~~30-DA = 2 lb/day~~

~~To calculate R1:~~

~~Lb/day, uncontrolled = (2.36 lb/day) / (1- 0.3333) = 3.54 lb/day~~

~~Lb/hr, uncontrolled = (3.54 lb/day) (day/24 hrs) = 0.15 lb/hr~~

- *PM_{10}*

Actual controlled = Actual uncontrolled = 3 lb/hr

Thus, control efficiency = 0%

To calculate R2 and R1:

Lb/day = [299.4 lb/month (Table 20)] (month/30 days) = 9.98 lb/day

Formatted: Indent: Left: 1.75"

Lb/hr = (9.98 lb/day) (day/24 hr) = 0.42 lb/hr

30-DA = (0.42 lb/hr) (24 hr/day) = ~~10.08~~9.98 lb/day (from NSR Data Summary Sheet)

Formatted: Indent: Left: 1.75", Hanging: 0.81", Tab stops: Not at 1.75"

~~ERCs required = (10.08 lb/day) (1.2) = 12.10 lb/day → 12 lb/day~~

~~To calculate R2 (= R1) based on annualized operating schedule:~~

~~Lb/day = [1995.63 lb/yr (commissioning yr = normal operating yr)] [yr/52 wk] [wk/7 days] = 5.48 lb/day~~

~~Lb/hr = [5.48 lb/day] [day/24 hr] = 0.22 lb/hr~~

~~30-DA = 5 lb/day~~

Formatted: Strikethrough

Formatted: Strikethrough

Formatted: Strikethrough

- *SO_x*

Actual controlled = Actual uncontrolled = 0.34 lb/hr

(based on 0.25 gr/100 scf average natural gas sulfur content)

Thus, control efficiency is 0%.

To calculate R2 and R1:

Lb/day = [33.8 lb/month (Table 20)] (month/30 days)
= 1.13 lb/day

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Lb/hr = (1.13 lb/day) (day/24 hr) = 0.047 lb/hr

30-DA = (0.05 lb/hr) (24 hr) = 1.213 lb/day (from NSR Data Summary Sheet)

~~ERCs required = (1.2 lb/day) (1.2) = 1.44 lb/day --> 1 lb/day~~

Formatted: Strikethrough

~~To calculate R2 and R1 based on annualized operating schedule:~~
~~Lb/day = [272.28 lb/yr (commissioning yr)] [yr/52 wk] [wk/7 days]~~
~~= 0.75 lb/day~~
~~Lb/hr = [0.75 lb/day] [day/24 hr] = 0.03 lb/hr~~
~~30-DA = 1 lb/day~~

b. Toxic Pollutants

The applicant provided the following toxic pollutant emissions calculations for each CTG in a table—Toxic Air Contaminant Emissions from Each Turbine--in Appendix C of the revised Application, for use in the Rule 1401 health risk assessment. I have verified the emission factors and calculations are correct. The emission calculations are shown in the table below.

Table 24—Toxic Air Contaminants per Turbine

Max Fuel Flow (HHV)		**480.6**	**MMBtu/hr**	**= 0.475**	**MMcf/hr**	
Maximum annual hours of operation		**698.751260**	**hr/yr**			
Pollutant	**CAS**	**Emission Factor (lb/MMBtu)**	**Emission Factor (lb/MMcf)**	**Emission factor source**	**Hourly Emission Rate (lb/hr)**	**Annual Emission Rate (lb/yr)**
1,3-Butadiene	106990	4.30E-07		AP-42	2.07E-04	2.60E-01~~1.44E-01~~
Acetaldehyde	75070	4.00E-05		AP-42	1.92E-02	2.42E+01~~1.34E+01~~
Acrolein	107028	3.62E-06		AP-42	1.74E-03	2.19E+00~~1.22E+00~~
Benzene	71432	3.26E-06		AP-42	1.57E-03	1.97E+00~~1.09E+00~~
Ethylbenzene	100414	3.20E-05		AP-42	1.54E-02	1.94E+01~~1.07E+01~~
Formaldehyde	50000	3.60E-04		AP-42	1.73E-01	2.18E+02~~1.21E+02~~
Propylene Oxide	75569	2.90E-05		AP-42	1.39E-02	1.76E+01~~9.74E+00~~
Toluene	108883	1.30E-04		AP-42	6.25E-02	7.87E+01~~4.37E+01~~
Xylenes	1330207	6.40E-05		AP-42	3.08E-02	3.88E+01~~2.15E+01~~
PAH						

Benzo(a)anthracene	56553	2.23E-08	2.26E-05	CATEF mean	1.07E-05	1.35E-02~~7.50E-03~~
Benzo(a)pyrene	50328	1.37E-08	1.39E-05	CATEF mean	6.60E-06	8.3[illegible]
Benzo(b)fluoranthene	205992	1.12E-08	1.13E-05	CATEF mean	5.37E-06	6.76E-03~~3.75E-03~~
Benzo(k)fluoranthene	207089	1.09E-08	1.10E-05	CATEF mean	5.22E-06	6.58E-03~~3.65E-03~~
Chrysene	218019	2.49E-08	2.52E-05	CATEF mean	1.20E-05	1.51E-02~~8.36E-03~~
Dibenz(a,h)anthracene	53703	2.32E-08	2.35E-05	CATEF mean	1.12E-05	1.41E-02~~7.80E-03~~
Indeno(1,2,3-cd)pyrene	193395	2.32E-08	2.35E-05	CATEF mean	1.12E-05	1.41E-02~~7.80E-03~~
Naphthalene	91203	1.64E-06	1.66E-03	CATEF mean	7.88E-04	9.93E-01~~5.51E-03~~
Total PAHs (other than naphthalene)					6.22E-05	7.86E-02~~1.71E-01~~
Total Annual HAP Emissions per Turbine, TPY						**2.01E-01~~1.12E-01~~**

Formatted: Tab stops: 5.5", Left + Not at 3"

Formatted Table

* Maximum annual operating hours is calculated as follows: [12 months/yr] [(90 hr/month) + (20 start-ups) (35 min/startup) (hr/60 min) + (20 shutdowns) (10 min/start-up) (hr/60 min)] = 1260 hrs/yr.

Emission factors for all toxic pollutants, except ammonia, formaldehyde, benzene, acrolein, and speciated PAHs, are from USEPA AP-42 Table 3.1-3 for uncontrolled natural gas-fired stationary turbines. Formaldehyde, benzene, and acrolein emission factors are from the Background document for AP-42 Section 3.1, Table 3.4-1 for a natural gas-fired combustion turbine with a CO catalyst. Speciated PAH emissions are from the California Air Toxics Emission Factors (CATEF) database for natural gas-fired combustion turbines with SCR and CO catalyst.

2. A/N 476654, 476657, 476660, 476663—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 1-4
Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

a. Criteria Pollutants
$NOx = CO = VOC = PM_{10} = SOx = 0$ lb/hr = 0 lb/day

b. Toxic Pollutants
From Table 10 above, the 5 ppmvd BACT level for ammonia results in an emission rate for ammonia of 3.64 lb/hr. Conservatively assuming that the ammonia is flowing at a constant rate of 3.64 lb/hr throughout the entire start-up and shutdown events, then ~~f~~for a ~~698.75~~1260-hr year~~.~~, ~~Thus,~~the total annual emissions = ~~2543.45~~4586.4 lb/yr

Operating schedule: 52 wk/yr, 7 days/wk, 24 hr/day (same as CTGs)

To calculate R1 and R2 for annualized operating schedule:

NH_3, lb/day = (~~2543.45~~4586.4 lb/yr) (yr/52 wk) (wk/7 days) = ~~6.99~~12.6 lb/day lb/hr = (~~6.99~~12.6 lb/day) (day/24 hr) = 0.~~29~~53 lb/hr

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Note: Ammonia is not a federal HAP.

3. A/N 476665—Ammonia Storage Tank
Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

No emissions are expected because the filling losses will be controlled by a vapor return line and the breathing losses by the 25 psig pressure valve.

NH_3 = 0 lb/hr = 0 lb/day

4. A/N 476666—Emergency ICE (Black Start Engine)
Operating schedule: ~~50~~52 wk/yr, ~~4~~1 day/wk, 1 hr/day

~~Pursuant to current District policy, the potential to emit for New Source Review purposes is based on 52 hrs/yr. The 4 day/wk is calculated as: (200 hr/yr) (yr/50 wk) (day/1 hr) = 4.0 day/wk~~

Formatted: Font color: Orange, Strikethrough

For non-RECLAIM pollutants, this engine ~~is~~would have been exempt from offset requirements per Rule 1304(a)(4), which exempts a source exclusively used as emergency standby equipment, if it were not for the court decision. Since the District is currently prohibited from using Rule 1304 offset exemptions by the court decision, offsets will be required for VOC, PM_{10}, and SOx if the 30-day average for any of these pollutants is over 0 lb/day. Because the NSR rules in Regulation XIII do not specify a basis for the operating schedule, the District policy is to use 50 hours of operation (or 52 hours to simplify the operating schedule).

Formatted: Underline

Formatted: Underline

For NOx, the RECLAIM rules ~~does~~do not provide ~~such~~ an offset exemption. Rule 2005(d) specifies the RECLAIM credit calculation shall be based on the potential to emit or on a permit condition limiting the source's emissions. Therefore, the number of RTCs required is based on 200 hours pursuant to condition C1.1. ~~because~~ Emergency internal combustion engines are limited by District rules~~, as implemented by condition C1.1,~~ to 200 hours.

Formatted: Font color: Red

Formatted: Underline

Formatted: Underline

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

Formatted: Not Strikethrough

Formatted: Font color: Red, Strikethrough

Formatted: Font color: Red

a. Criteria Pollutants
NOx
NOx, uncontrolled = NOx, controlled

According to RECLAIM Engineer Susan Tsai, RECLAIM allows the use of the BACT limit for the emission factor without requiring source testing for confirmation, but not the District certified emission level (4.08 g/bhp-hr for this

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

engine). BACT for NOx + ROG is 4.8 g/bhp-hr. As BACT for only NOx is not provided, the entire 4.8 g/bhp-hr is used as the emission factor.

NOx, lb/hr = (1141 bhp) (4.8 g/bhp-hr BACT) (lb/454 g) = 12.06 lb/hr
lb/day = (12.06 lb/hr) (1 hr/day) = 12.06 lb/day
~~lb/yr = (12.06 lb/day) (4 day/wk) (50 wk/yr) = 2412 lb/yr RTC~~
30-DA = (12.06 lb/day) (~~4~~1 day/wk x 4.33 /30 days) = ~~6.96~~1.75 lb/day ~~7~~(NSR Data Summary Sheet)

Number of RTCs required:
Condition I296.2 sets forth the RTCs required for the commissioning year and subsequent normal operating years.

RTCs required each year = (12.06 lb/hr) (200 hours) = 2412 lb/yr

CO
CO, uncontrolled = CO, controlled.

CO, lb/hr = (1141 bhp) (2.6 g/bhp-hr BACT) (lb/454 g) = 6.53 lb/hr
lb/day = (6.53 lb/hr) (1 hr/day) = 6.53 lb/day
~~lb/yr = (6.53 lb/day) (4 day/wk) (50 wk/yr) = 1306 lb/yr~~
30 DA = (6.53 lb/day) (~~4~~1 day/wk x 4.33 /30 days) = 0.95~~3.77~~ lb/day (NSR Data Summary Sheet)

ERCs required: None because CO is in attainment.

VOC
VOC, uncontrolled = VOC, controlled
Use certified emission factor of 0.02 g/bhp-hr, because the BACT limit is for NOx + ROG.

VOC, lb/hr = (1141 bhp) (0.02 g/bhp-hr per certification) (lb/454 g) = 0.050 lb/hr
lb/day = (0.050 lb/hr) (1 hr/day) = 0.050 lb/day
~~lb/yr = (0.050 lb/day) (4 day/wk) (50 wk/yr) = 10 lb/yr~~
30 DA = (0.050 lb/day) (~~4~~1 day/wk x 4.33 /30 days) = 0.01~~0.029~~ lb/day (NSR Data Summary Sheet)~~0~~

ERCs required: 0 lb/day

PM_{10}
The diesel particulate filter is CARB certified for 85% reduction.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

- Uncontrolled
  PM_{10}, lb/hr = (1141 bhp) (0.15 g/bhp-hr PM BACT) (0.96 PM_{10}/PM) (lb/454 g) = 0.36 lb/hr
  lb/day = (0.36 lb/hr) (1 hr/day) = 0.36 lb/day

- Controlled
  PM_{10}, lb/hr = (0.36 lb/hr) (1-0.85 control) = 0.054 lb/hr
  lb/day = (0.054 lb/hr) (1 hr/day) = 0.054 lb/day
  ~~lb/yr = (0.054 lb/day) (4 day/wk) (50 wk/yr) = 10.8 lb/yr~~
  30 DA = (0.054 lb/day) (~~4~~1 day/wk x 4.33 /30 days) = ~~0.031~~0.01 lb/day (NSR Data Summary Sheet)

  ERCs required: 0 lb/day

SOx
SOx, uncontrolled = SOx, controlled

SO_x, lb/hr = (1141 bhp) (0.0049 g/bhp-hr for 15 ppmw fuel) (lb/454 g) = 0.012 lb/hr
lb/day = (0.012 lb/hr) (1 hr/day) = 0.012 lb/day
~~lb/yr = (0.012 lb/day) (4 day/wk) (50 wk/yr) = 2.46 lb/yr~~
30 DA = (0.012 lb/day) (14 day/wk x 4.33 /30 days) = ~~0.07~~0 lb/day (NSR Data Summary Sheet)

ERCs required: 0 lb/day

b. Toxic Pollutants
Although the black start engine is exempt from modeling pursuant to Rules 1304(a)(4) and 2005(k)(5), which both exempt standby equipment, CEQA requires modeling for the total facility. The District modeling group's evaluation of the air quality modeling protocol statesd the risks of the diesel-fired black start engine are determined by its particulate emissions, and the VOC and particulate emissions from the black start engine are not to be speciated.

The HRA used a particulate emission rate of 0.33 lbs/hr, provided by the manufacturer based on the BACT limit of 0.15 g/bhp-hr (Tier 2), with an 85% control efficiency from the filter.

PM_{10}, lb/yr = (0.33 lbs/hr) (1 – 0.85) (200 hr) = 9.9 lb/yr

Note: Diesel particulate is not a federal HAP.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

5. A/N 481185—Oil Water Separator
Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

The applicant provided emissions calculations for working and breathing losses using the Tanks 4.0 program. Throughput is 55,000 gal/year, 10% diesel oil by volume.

VOC, lb/yr = 0.59 lb/yr [Tanks 4.0]
lb/hr = (0.59 lb/yr) (yr/52 wk) (wk/7 days) (day/24 hr) = 0.0000675 lb/hr
lb/day = (0.0000675 lb/hr) (24 hr/day) = 0.00162 lb/day
30 DA = (0.00162 lb/day) → 0 lb/day

6. Rule 219 Exempt--Cooling Tower
Because the cooling tower is exempt from permitting as long as the risk is less than 1 in a million, TAC emissions are required to be calculated. The applicant sampled the water anticipated to be used for makeup to the cooling tower to determine the maximum concentration of each TAC. The applicant provided the following toxic pollutant emissions calculations for the cooling tower in a table—Toxic Air Contaminant Emissions from Chiller Cooling Tower--in Appendix C of the revised Application. I have verified the emission factors and calculations are correct. The emissions calculation are shown in the table below.

Formatted: Left, Indent: Left: 0.5"

Table 25 -- Emission Rates for Cooling Tower

Toxic Air Contaminant	TAC Concentration in water		Emissions per cell		Total tower emissions (4 cells)	
	ug/liter	lb/(1000 gallon)	lb/hr	lb/yr	lb/hr	lb/yr
Antimony**	0.6	0.000005	5.81E-08	2.93E-04	2.33E-07	1.17E-03~~6.50E-04~~
Arsenic	4.8	0.000040	4.65E-07	2.34E-03	1.86E-06	9.37E-03~~5.20E-03~~
Beryllium	0.1	0.000001	9.69E-09	4.88E-05	3.88E-08	1.95E-04~~1.08E-04~~
Cadmium	0.1	0.000001	9.69E-09	4.88E-05	3.88E-08	1.95E-04~~1.08E-04~~
Chlorine	9300	0.077603	9.01E-04	4.54E+00	3.60E-03	1.82E+01~~1.01E+01~~
Chromium	1.1	0.000009	1.07E-07	5.37E-04	4.26E-07	2.15E-03~~1.19E-03~~
Cobalt **	2.2	0.000018	2.13E-07	1.07E-03	8.53E-07	4.30E-03~~2.38E-03~~
Copper *	28	0.000234	2.71E-06	1.37E-02	1.09E-05	5.47E-02~~3.03E-02~~
Cyanide	46	0.000384	4.46E-06	2.25E-02	1.78E-05	8.98E-02~~4.98E-02~~
Fluoride *	30	0.000250	2.91E-06	1.46E-02	1.16E-05	5.86E-02~~3.25E-02~~
Lead	1.6	0.000013	1.55E-07	7.81E-04	6.20E-07	3.12E-03~~1.73E-03~~
Manganese	9.2	0.000077	8.91E-07	4.49E-03	3.57E-06	1.80E-02~~9.96E-03~~
Mercury	0.05	0.000000	4.84E-09	2.44E-05	1.94E-08	9.77E-05~~5.42E-05~~
Nickel	0.1	0.000001	9.69E-09	4.88E-05	3.88E-08	1.95E-04~~1.08E-04~~
Selenium	16	0.000134	1.55E-06	7.81E-03	6.20E-06	3.12E-02~~1.73E-02~~

Silica *	970	0.008094	9.40E-05	4.74E-01	3.76E-04	1.89E+00~~1.05E+00~~
Sulfate *	2550	0.021278	2.47E-04	1.25E+00	9.88E-04	4.98E+00~~2.76E+00~~
Total Annual HAP Emissions, TPY						**9.16E-03~~5.08E-03~~**

* Not a federal HAP
** Not a Rule 1401 toxic air contaminant

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Emission rate for each TAC, lb/hr = [circulating water flow rate (gal/min)/1000] x (60 min/hr) x [lb of TAC per 1000 gallons of makeup water] x [cycles of concentration buildup within the cooling water cycle] x [percent of circulating water emitted as drift]/100

where:

Circulating water flow rate = 7,740 gal/min for all four cells
Lb of TAC per 1000 gallons of makeup water = based on water sample analysis
Cycles of concentration buildup within the cooling water cycle = 10 cycles (design)
Percent of circulating water emitted as drift = 0.001% (vendor guarantee for drift elimination system)

Emission rate for each TAC, lb/yr = (TAC, lb/hr) x (~~2795~~5040 hrs/yr).
~~With t~~The annual hours are calculated as: (~~698.75~~1260 hr/yr max for each turbine) x (4 turbines) = 5040 hours~~.~~

(The emissions for one cell is provided because a four-cell tower is modeled as four point separate point sources.)

7. Total Facility/Project Emissions
   a. Criteria Pollutants
      - *Annual Emissions*

        The maximum annual emissions for the entire facility/project are necessary to determine ~~(1)~~ whether the facility is a major source~~, and (2) whether the annual emissions for VOC, PM_{10}, or SOx are greater than 4 tpy and therefore require offsets~~. For these purposes, the annual emissions are from permitted equipment only. The maximum annual emissions is the higher of the annual emissions for the commissioning year or a normal operating year.

        The annual emissions for the entire facility are comprised of the emissions from the CTGs, ammonia tank, black start engine, and oil water separator. The maximum annual facility/project emissions for the commissioning year and normal operating year are shown in the two tables below.

Commissioning Year

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Table 26—Maximum Annual Facility/Project Emissions, Commissioning Year

Equipment	NO_x, lb/yr	CO, lb/yr	VOC, lb/yr	PM_{10}, lb/yr	SO_x, lb/yr
Turbine No. 1	~~6639.92~~~~9745.85~~ 9676.55	8375.98~~5712.92~~	1548~~770.94~~	3495.69~~1995.63~~	397.36~~272~~
Turbine No. 2	~~9745.85~~ 9676.55~~6639.92~~	8375.98~~5712.92~~	1548~~770.94~~	3495.69~~1995.63~~	397.36~~272~~
Turbine No. 3	~~9745.85~~ 9676.55~~6639.92~~	8375.98~~5712.92~~	1548~~770.94~~	3495.69~~1995.63~~	397.36~~272~~
Turbine No. 4	~~9745.85~~ 9676.55~~6639.92~~	8375.98~~5712.92~~	1548~~770.94~~	3495.69~~1995.63~~	397.36~~272~~
Total for Four Turbines	~~**38,983.40**~~ **38,706.20~~26,559.68~~**	**33,503.92~~22,851.68~~**	**6192 ~~3083.76~~**	**13,982.76~~7982.52~~**	**1589.44~~10~~**
Ammonia Tank	0	0	0	0	0
Emergency ICE, black start engine	2412	1306	10	10.8	2.46
Oil water separator	0	0	0	0	0
Total for Project	~~**41,395.40**~~ **41,118.20** ~~**(20.70 tpy)**~~ **(20.56 tpy)~~28,971.68 (14.49 tpy)~~**	**34,809.92 (17.40 tpy)~~24,157.68 (12.08 tpy)~~**	**6202 (3.10 tpy)~~3093.76 (1.55 tpy)~~**	**13,993.56 (7.0 tpy)~~7993.32 (3.997 tpy)~~**	**1,591.90 (0.80 tpy)~~1091.~~ ~~(0.55 tpy)~~**

Formatted: Font color: Orange, Strikethrough
Formatted: Underline, Font color: Orange
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Underline, Font color: Orange
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough

Normal Operating Year

Table 27—Maximum Annual Facility/Project Emissions, Normal Operating Year

Equipment	NO_x, lb/yr	CO, lb/yr	VOC, lb/yr	PM_{10}, lb/yr	SO_x, lb/yr
Turbine No. 1	~~6960~~ 6885.6~~3828.72~~	5712~~3161.36~~	1548~~859.14~~	3588~~1995.63~~	408~~225.32~~
Turbine	~~6960~~	5712~~3161.36~~	1548~~859.14~~	3588~~1995.63~~	408~~225.32~~

Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough
Formatted: Font color: Orange, Strikethrough

No. 2	6885.6~~3828.72~~				
Turbine No. 3	~~6960~~ 6885.6~~3828.72~~	5712~~3161.36~~	1548~~859.14~~	3588~~1995.63~~	408~~225.32~~
Turbine No. 4	~~6960~~ 6885.6~~3828.72~~	5712~~3161.36~~	1548~~859.14~~	3588~~1995.63~~	408~~225.32~~
Total for Four Turbines	~~27,840~~ 27,542.4~~15,314.88~~	22,848~~12,645.44~~	6192~~3436.56~~	14,352~~7982.52~~	1632~~901.28~~
Ammonia Tank	0	0	0	0	0
Emergency ICE, Black Start Engine	2412	1306	10	10.8	2.46
Oil Water Separator	0	0	0	0	0
Total for Project	~~30,252~~ 29,954.40 ~~(15.13 tpy)~~ (14.98 tpy)~~17,726.88 (8.86 tpy)~~	24,154 (12.08 tpy)~~13,951.44 (6.98 tpy)~~	6202 (3.10 tpy)~~3446.56 (1.72 tpy)~~	14,362.8 (7.18 tpy)~~7993.32 (3.997 tpy)~~	1634.46 (0.82 tpy)~~903.74 (0.45 tpy)~~

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted: Font color: Orange, Strikethrough

Formatted: Font color: Orange, Strikethrough

Formatted: Font color: Orange, Strikethrough

Formatted: Font color: Orange, Strikethrough

Formatted: Font color: Orange, Strikethrough

Formatted: Font color: Orange, Strikethrough

Formatted: Font color: Orange, Strikethrough

Formatted: Font color: Orange, Strikethrough

Formatted: Underline, Font color: Orange

Formatted: Font color: Orange, Strikethrough

b. Toxic Contaminants/HAPS

The maximum annual toxic contaminants for the facility are not required to be calculated because Rule 1401 health risk assessments are based on a permit unit. The maximum annual hazardous air pollutants (HAPs), however, are required to be calculated to determine applicability of the NESHAPS found in 40 CFR Part 63.

Table 28A—Annual Facility/Project HAPs Emissions by Permit Unit

Permit Unit	Total Annual HAP Emissions, tpy
Turbine No. 1	0.201~~0.112~~
Turbine No. 2	0.201~~0.112~~
Turbine No. 3	0.201~~0.112~~
Turbine No. 4	0.201~~0.112~~
ICE, Black Start Engine	0.000
Cooling Tower	0.00~~5~~9
Total all sources	~~0.451~~0.813

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Table 28B—Annual Facility/Project HAPs Emissions by Component

Pollutant	Total Annual HAP Emissions All Sources (ton/yr)
1,3-Butadiene	~~2.89E-04~~5.2E-04
Acetaldehyde	~~2.69E-02~~4.84E-02
Acrolein	~~2.43E-03~~4.38E-03
Benzene	~~2.19E-03~~3.94E-03
Ethylbenzene	~~2.15E-02~~9.7E-03
Formaldehyde	~~2.42E-01~~4.36E-01
Propylene Oxide	~~1.95E-02~~3.52E-02
Toluene	1.57E-01~~8.73E-02~~
Xylenes	7.763-02~~4.30E-02~~
Naphthalene	1.99E-03~~0.001~~
PAHs (other than naphthalene)	1.57E-04~~3.42E-04~~
Antimony	~~3.25E-07~~2.34E-06
Arsenic	~~2.60E-06~~1.87E-05
Beryllium	~~5.42E-08~~3.9E-07
Cadmium	~~5.42E-08~~3.9E-07
Chlorine	~~5.04E-03~~3.64E-02
Chromium	~~5.96E-07~~4.3E-06
Cobalt	~~1.19E-06~~8.6E-06
Cyanide	~~2.49E-05~~1.80E-04
Lead	6.24E-06~~8.66E-07~~
Manganese	~~4.98E-06~~3.60E-05
Mercury	~~2.71E-08~~1.95E-07
Nickel	3.9E-07~~5.42E-08~~
Selenium	~~8.66E-06~~6.24E-05
Total	**~~0.451~~0.813**

Note: Ammonia and diesel particulate are not federal HAPs.

Summary of Offsets Required based upon total project emissions:

Formatted: Underline

30-Day Aves

Formatted: Centered

Permit Unit	VOC	SOx	PM10
Turbine 1	4.31	1.13	9.98

Formatted: Centered

Formatted: Centered

Turbine 2	4.31	1.13	9.98
Turbine 3	4.31	1.13	9.98
Turbine 4	4.31	1.13	9.98
SCR 1	0	0	0
SCR 2	0	0	0
SCR 3	0	0	0
SCR 4	0	0	0
NH3 Storage	0	0	0
Waste Water Treat	0	0	0
Emrg ICE	0.01	0	0.01
Total Project	17.25	4.52	39.93
1.2 offset factor	20.69	5.42	47.92
ERC's Required	21	5	48

RULE EVALUATION

- **District Rules and Regulations**

  Rule 212-Standards for Approving Permits

  Rule 2005(h) – RECLAIM Public Notice

  Rule 212(c) provides that a project with a net emission increase requires public notice prior to the issuance of a permit if: **(1)** the equipment is located within 1,000 feet of the outer boundary of a school; **(2)** on-site emission increase exceeds any of the daily maximums specified in Rule 212(g); or **(3)** the MICR is equal to or greater than one in a million (1E-6) during a lifetime (70 years) for facilities with more than one permitted unit, source under Regulation XX, or equipment under Regulation XXX unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million (10E-06) using the risk assessment procedures and toxic air contaminants specified under Rule 1402; or, ten in a million (10E-6) during a lifetime (70 years) for facilities with a single permitted unit, source under Regulation XX, or equipment under Regulation XXX. Rule 2005(h) requires compliance with Rule 212 for NOx emissions only.

  Public notice **is** required for this project pursuant to subdivision (c)(2), but not subdivisions (c)(1) and (c)(3), as discussed below.

  - Rule 212(c)(1)--The proposed equipment will **not** be located within 1000 feet of the outer boundary of a school, because the nearest K-12 school, Melrose Elementary, 974 S. Melrose St., Placentia, is located 0.71 miles (3749 ft) away. The following table shows the schools nearest to the facility, with the distances provided by the Mapquest program found at http://www.mapquest.com.

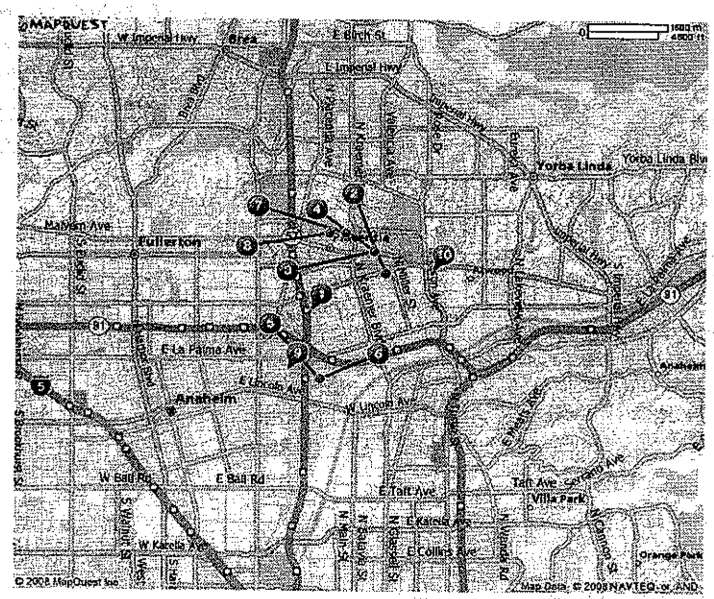
Formatted: Tab stops: 5.5", Left + Not at 3" + 6"
Formatted: Centered
Formatted: Centered
Formatted: Centered
Formatted: Centered
Formatted: Centered
Formatted: Centered
Formatted: Centered
Formatted: Centered
Formatted: Centered
Formatted: Centered
Formatted: Centered
Formatted Table
Formatted: Underline
Formatted: Centered
Formatted: Font: Bold, Underline
Formatted: Centered
Formatted: Font: 12 pt

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT *ENGINEERING AND COMPLIANCE DIVISION* APPLICATION PROCESSING AND CALCULATIONS	PAGES 138	PAGE 83
	APPL. NO. 476650, -651, -654, -656, -657, -659, -660, -661, -663,-665, -666, 481185	DATE ~~61/2119/2009~~6/24/2009
	PROCESSED BY V. Lee	CHECKED BY

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Table 29 – Nearest Schools (K – 12)

Name of School	Address	Mapquest Distance Miles (feet)
1. Melrose Elementary	974 S. Melrose, Placentia	0.71 (3749)
2. Placentia Education Center *Note: 7/1/08—Telephone disconnected, no additional information available.*	3323 E. Orangethorpe, Anaheim	0.82 (4330)
3. Tynes Child Care	735 Stanford, Placentia	1.04 (5491)
4. John O Tynes Elementary	735 Stanford, Placentia	1.04 (5491)
5. Rio Vista Child Care	310 N. Rio Vista, Anaheim	1.13 (5966)
6. Rio Vista Elementary	310 N. Rio Vista, Anaheim	1.13 (5966)
7. Kraemer Middle School	645 N. Angelina, Placentia	1.3 (6864)
8. Valencia High	500 N. Bradford, Placentia	1.36 (7181)
9. Sunkist Elementary	500 N. Sunkist, Anaheim	1.36 (7181)



- o Rule 212(c)(2)--The daily maximum emission increases for NOx (112.69 lb/day) and PM_{10} (70.44 lb/day) resulting from the project **will** exceed the daily maximum thresholds set forth in subdivision (g) of 40 lb/day NOx and 30 lb/day PM_{10}.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

- Rule 212(c)(3)--The increase in toxic emissions from each CTG **will not** expose a person to a maximum individual cancer risk that is greater than or equal to one in a million during a lifetime (70 years).

The public notice requirements for subdivision (c)(2) are found in subdivisions (d) and (g). Subdivision (d) requires the applicant to distribute the public notice to each address within ¼ mile radius of the project. Subdivision (g) requires that the public notification and comment process include all applicable provisions of 40 CFR Part 51, Section 51.161(b) and 40 CFR Part 124, Section 124.10. The minimum requirements specified in the above documents are included in (g)(1), (g)(2), and (g)(3). The public notice ~~will be~~ is required to be issued in accordance with the aforementioned requirements followed by a 30-day public comment period prior to issuance of the P/Cs. The Rule 212(g) public notice period was anticipated to run concurrently with the Rule 3006 Title V public notice period for a single 30-day public comment period. (The Title V public notice requirements are discussed below under *Regulation XXX – Title V*.)

- ***Public Notice Distribution and Publication***

  On February 20, 2009, the AQMD mailed the Rules 212 and 3006 public notice to the applicant and government agencies as required by Rule 212(g)(3). The letter to the applicant stated that it was required to distribute the enclosed public notice to each address within a ¼-mile radius of the project and to provide written verification and proof of distribution, as required by Rule 212(d). On the same day, the AQMD sent a copy of the application, draft permit, and engineering analysis to the Anaheim Main Public Library and AQMD library for display as required by Rule 212(g)(1). On February 24, the AQMD mailed the public notice, with a stated distribution date of February 25, 2009, to approximately 2300 interested parties on the applicable CEC mailing lists and AQMD subscription lists, as required by Rule 212(g). On February 25, the public notice was published in The Register as required by Rule 212(g)(2). Therefore, the 30-day public notice period started on February 25 and ended on March 27.

  On April 18 and April 20, 2009, the applicant's representative finally mailed the public notice, with a stated distribution date of February 25, 2009, to addresses within 1/2 mile (not ¼ mile) radius of the project. The noticing was invalid because the representative did not fill in the correct distribution date and was unable to provide proof of distribution. On April 23, the representative re-mailed the public notices with the correct distribution date at the post office. Therefore, a second 30-day public notice period started on April 23 and ended on May 23, 2009.

Formatted: Font color: Red, Strikethrough
Formatted: No underline
Formatted: Underline, Font color: Red
Formatted: Underline
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Underline, Font color: Red
Formatted: Font: Italic
Formatted: Font: Italic
Formatted: Bullets and Numbering
Formatted: Indent: Left: 0.5"

- ***Public Hearing Requests and Comments***

  Please see *Regulation XXX – Title V*, below, for a summary of public comments received during the two public comment periods.

Formatted: Bullets and Numbering
Formatted: Underline
Formatted: Indent: Left: 0.5"
Formatted: Underline

Rule 218 – Continuous Emission Monitoring

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

In accordance with Rule 218(c), (e), (f), the applicant is required to submit an "Application for CEMS" for a CO CEMS for each CTG and adhere to retention of records and reporting requirements once approval to operate the CO CEMS is granted. Compliance with this rule is expected.

Rule 401 – Visible Emissions

This rule prohibits the discharge of visible emissions for a period aggregating more than three minutes in any one hour which is as dark or darker in shade than Ringelmann No. 1. Visible emissions are not expected under normal operation from either the CTGs, engine, or ammonia tank.

Rule 402 - Nuisance

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The proposed equipment, including the CTGs, engine, and ammonia tank, is not expected to create nuisance problems.

Rule 403 – Fugitive Dust

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule includes the prohibition of fugitive dust emissions beyond the property line of the emission source.

To mitigate fugitive dust emissions during construction, the applicant will submit a fugitive dust plan to both the AQMD and CEC prior to the commencement of construction. Such measures include covering loose material on haul vehicles, watering, and using chemical stabilizers when necessary. The installation and operation of the CTGs, engine, and ammonia tank are expected to comply with this rule.

Rule 407 – Liquid and Gaseous Air Contaminants

This rule applies to the CTGs but exempts the black start engine pursuant to subdivision (b)(1). It limits CO emissions to 2000 ppmv. The CO emissions from the turbine will be controlled by an oxidation catalyst to 4 ppmvd at 15% O2. The SO2 portion of the rule does not apply per subdivision (c)(2), because the natural gas fired in the CTGs will comply with the sulfur limit in Rule 431.1. Therefore, compliance with this rule is expected.

Rule 409 – Combustion Contaminants

This rule applies to the CTGs but not to internal combustion engines. It restricts the discharge of contaminants from the combustion of fuel to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over 15 minutes. Each CTG is

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the grain loading is expected to be 0.012 gr/scf.

Grain Loading = [(A x B)/(C x D)] x 7000 gr/lb

where:

A = Maximum PM_{10} emission rate during normal operation, 3.0 lb/hr (vendor data)
B = Rule specified percent of CO2 in the exhaust (12%)
C = Percent of CO2 in the exhaust (approx. 4.29% for natural gas)
D = Stack exhaust flow rate, scf/hr

$$D = F_d \times \frac{20.9}{(20.9 - \%\,O_2)} \times TFD = 8710 \times \frac{20.9}{17.9} \times 479 = 4.87\,E{+}06 \text{ scf/hr}$$

where:

F_d = Dry F factor for fuel type, 8710 dscf/MMBtu
O_2 = Rule specific dry oxygen content in the effluent stream, 3%
TFD = Total fired duty measured at HHV, 479 MMBTU/hr

Grain Loading = [(3.0 x 12) / (4.29) (4.87E+06)] x 7000 = 0.012 gr/scf < 0.1 gr/scf limit

Rule 431.1 – Sulfur Content of Gaseous Fuels
The natural gas supplied to the turbine is expected to comply with the 16 ppmv sulfur limit (calculated as H2S) specified in this rule, because commercial grade natural gas has an average sulfur content of 4 ppm. The reporting and record keeping requirements are set forth in subdivision (e) of this rule.

Rule 431.2—Sulfur Content of Liquid Fuels
The diesel fuel supplied to the black start engine is expected to comply with the 15 ppmv by weight sulfur limit supplied in this rule. [See Condition no. F14.1.]

Rule 474—Fuel Burning Equipment-Oxides of Nitrogen
This rule is superseded by NOx RECLAIM according to Rule 2001, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.

Rule 475 – Electric Power Generating Equipment
This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976, and establishes a limit for combustion contaminants (particulate matter) of 11 lbs/hr or

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

0.01 grains/scf. Compliance is achieved if either the mass limit or the concentration limit is met.

Each CTG is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the concentration is expected to be 0.0044 gr/scf.

Combustion Particulate (gr/scf) = (PM_{10}, lb/hr / Stack Exhaust Flow, scf) x 7000 gr/lb

PM_{10} = 3.0 lb/hr (vendor data)
Stack exhaust flow = 4.87 E+06 scf/hr (see Rule 409 analysis, above)

Combustion Particulate = (3.0 / 4.87 E+06) x 7000 = 0.0043 gr/scf < 0.01 gr/scf limit

Rule 1110.2—Emissions from Gaseous- and Liquid-Fueled Engines
Since the black start engine is an emergency engine that will operate less than 200 hours per year, it is exempt from this rule pursuant to subdivision (h)(2).

Rule 1134 – Emissions of NOx from Stationary Gas Turbines
This rule applies to gas turbines, 0.3 MW and larger, installed on or before August 4, 1989. Therefore, as a new installation, the proposed CTGs are not subject to this rule.

Rule 1135 – Emissions of NOx from Electric Power Generating Systems
This rule applies to electric power generating systems owned and operated by, or sell power to Southern California Edison, Los Angeles Dept. of Water and Power, City of Burbank, City of Glendale, City of Pasadena, or any of their successors. This rule is not applicable to the City of Anaheim.

NEW SOURCE REVIEW (NSR) ANALYSIS
The following section covers New Source Review requirements only. (PSD applicability and requirements are further discussed under REGULATION XVII—Prevention of Significant Deterioration, below. RECLAIM applicability and requirements are further discussed under REGULATION XX-Regional Clean Air Incentives Market (RECLAIM), below.)

The applicable NSR requirements are summarized in the table below.

Table 30 - Applicable NSR Rules

Applicable NSR Rules for Non-RECLAIM Pollutants (CO, VOC, PM_{10}, SOx)	Applicable NSR Rules for RECLAIM Pollutants (NOx)
Rule 1303(a)(1)–BACT	Rule 2005(b)(1)(A)-BACT

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Rule 1303(b)(1)-Modeling	Rule 2005(b)(1)(B)-Modeling
Rule 1303(b)(2)-Offsets	Rule 2005(b)(2)-Offsets
Rule 1303(b)(3)-Sensitive Zone Requirements	Rule 2005(e)-Trading Zone Restrictions
Rule 1303(b)(4)-Facility Compliance	Rule 2005(g)-Additional Federal Requirements for Major Stationary Sources
Rule 1303(b)(5)-Major Polluting Facilities	Rule 2005(h)-Public Notice
	Rule 2005(i)-Rule 1401 Compliance
Rule 1703(a)(2) – Prevention of Significant Deterioration (PSD) – BACT (NOx, CO, and SOx)	Rule 2005(j)-Compliance with Federal/State NSR

- *Rule 1303(a)(1)—BACT (CO, VOC, PM_{10}, SOx)*
- *Rule 1703(a)(2)—PSD-BACT (NOx, CO, and SOx)*
- *Rule 2005(b)(1)(A)—BACT (NOx)*

Best Available Control Technology (BACT) is required for a new source which results in an emission increase that is greater than 1 lb/day of any criteria pollutant, any ozone depleting compound, or ammonia. Consequently, BACT is applicable to all permit units in this project, except for the ammonia tank and oil water separator. The bases for the applicability of each rule is discussed below.

Rule 1703(a)(2)-- As explained below under *REGULATION XVII – Prevention of Significant Deterioration*, this rule requiring BACT for attainment air contaminants is applicable to CPP. Since the District is presently in attainment with NAAQS for NOx, CO, and SOx, this rule is applicable to those pollutants.

Rule 1303(a)(1)—This rule, as amended 12/6/02, requires BACT for nonattainment air contaminants. The District is not in attainment for PM_{10} and ozone, but is in attainment for NOx, CO, and SOx. However, since NOx, SOx, and VOC are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well. NOx and VOC are precursors to ozone, PM_{10}, and $PM_{2.5}$. SOx is a precursor to PM_{10} and $PM_{2.5}$. Thus, this rule requires BACT for PM_{10}, NOx, SOx, and VOC.

Rule 2005(b)(1)(A)—This rule requires BACT for NOx emissions for RECLAIM facilities.

1. A/N 476651, 476656, 476659, 476661—Combustion Gas Turbines Nos. 1 - 4
2. A/N 476654, 476657, 476660, 476663—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 1-4
   - *AQMD BACT Compliance Determination*
   - *AQMD BACT Compliance Determination*

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Rule 1302(h) defines BACT as "the most stringent emission limitation or control technique which:

(1) has been achieved in practice [AIP] for such category or class of source; or

(2) is contained in any state implementation plan (SIP) approved by the United States Environmental Protection Agency (EPA) approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or

(3) is any other emission limitation or control technique, found by the Executive officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board."

Rule 1303(a)(2) provides that BACT for sources located at major polluting facilities shall be at least as stringent as Lowest Achievable Emissions Rate (LAER) as defined in the federal Clean Air Act Section 171(3). For major polluting facilities, the lowest achievable emission rate (LAER) are determined on a permit-by-permit basis. For practical purposes, nearly all AQMD LAER determinations will be based on AIP LAER because it is generally more stringent than LAER based on SIP, and because state law constrains the District from using the third approach.

An emission limit or control technology may be considered achieved in practice for a category or class of source if it exists in any of the following regulatory documents or programs: AQMD BACT Guidelines, CAPCOA BACT Clearinghouse, USEPA RACT/BACT/LAER Clearinghouse, other districts' and states' BACT Guidelines, and BACT/LAER requirements in New Source Review permits issued by AQMD or other agencies. (In addition to the aforementioned means of being determined as AIP, a control technology or emission limit may also be considered as AIP if it meets all of the following criteria: commercial availability, reliability, and effectiveness. The top-down BACT analysis below will discuss various control technologies.)

The current BACT/LAER guidelines for simple cycle gas turbines are based on the AQMD permits issued to the City of Riverside Public Utilities Department on 4/28/05. The guidelines are set forth in the table below.

Table 31—Simple Cycle Gas Turbine MSBACT/LAER Requirements

	NOx	CO*	VOC	PM_{10}/SOx	NH_3

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Simple Cycle Gas Turbine BACT Limits	2.5 ppmvd @ 15% O_2, 1-hr average	6.0 ppmvd @ 15% O_2, 1-hr average*	2.0 ppmvd @ 15% O_2, 1-hr average	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5.0 ppmvd @ 15% O_2, 1-hr average

The warranted emissions levels for normal operation for the proposed CTGs controlled with selective catalytic reduction and CO oxidation catalyst are shown in the table below. Thus, the proposed CTGs are expected to meet the BACT/LAER standards.

Table 32—General Electric Guaranteed Emissions Levels

	NOx	CO*	VOC	PM_{10}/SOx	NH_3
GE Performance Guarantee	2.3 ppmvd @ 15% O_2	6.0 ppmvd @ 15% O_2	2.0 ppmvd @ 15% O_2	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5 ppmvd @ 15% O_2

* For this project, the BACT limit for CO will be 4.0 ppmvd, instead of the 6.0 ppmvd, because the District has sufficient test results for initial and periodic monitoring source testing for LM6000 turbines installed at existing power plants to demonstrate the 4.0 ppmvd to be achieved in practice. Further, the applicant has confirmed with GE that the 4.0 will be consistently achievable.

Condition no. A99.1, A99.2, and A99.3 provides that the BACT limits of 2.5 ppm NOx, 4.0 ppm CO, and 2.0 ppm ROG shall not apply during commissioning, startup and shutdown periods.

During commissioning, it is not technically feasible for the CTGs to meet BACT limits during the entire period because the combustors may not be optimally tuned and the emissions are only partially abated because the water injection, CO catalyst, and SCR catalyst are installed and tested in stages. The turbines, however, are typically operated at less than 100% load during the testing. (See Table 12 above for the duration and emission rates of each commissioning activity.) To limit commissioning emissions, condition no. A99.1, A99.2, and A99.3 limit the commissioning period to 156 hours.

During startups, it is not technically feasible for the CTGs to meet BACT limits during the entire startup because the SCR and CO catalysts that are used to achieve the required emissions reductions are not fully effective when the surface of the catalysts are below the manufacturers' recommended operating range. (See Table 13 above for the startup emissions profile.) The water injection into the CTGs, however, does reduce the NOx emissions to 25 ppmv prior to entry into the SCR and CO catalysts. To limit startup emissions, condition nos. A99.1, A99.2, and A99.3 limit each startup to 35 minutes and limit the number of startups to ~~129~~240 per year. Further, these proof of how the AQMD proposes to indemnify business owners and employees in the event that the statistics upon which the AQMD's determination is based proves to be erroneous at some date future. The AQMD sent a response letter, dated **??**, which **??**

The CEC submitted a comment letter, dated March 10, 2009, and an e-mail with an additional comment, dated March 16, 2009, regarding the draft facility permit and the PDOC. The AQMD responded to these comments in an attachment to the Final Determination of Compliance (FDOC) issuance letter, dated **??**. The revisions are incorporated into the FDOC.

The City of Anaheim submitted a comment letter, dated March 16, 2009, proposing minor changes in two draft permit conditions. The AQMD sent a response letter, dated **??**. The revisions are incorporated into the FDOC.

- ***Joint CEC/AQMD Public Meeting***
  In response to the public hearing requests from the Cities of Yorba Linda and Placentia, the AQMD held a joint public meeting with the CEC on May 21, 2009, at the City of Anaheim, City Hall Council Chambers, where the AQMD responded to comments and questions from interested members of the public. A copy of the public notice of the meeting was mailed to the two cities and the public in advance of the meeting. At the meeting, a consultant representing the City of Yorba Linda gave a presentation regarding the advantages of a once-through steam generation (OTSG) combined cycle system over a simple cycle system. At the joint meeting the CEC and staff indicated the CEC intends to consider those comments before it issued the Preliminary Staff Assessment.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"
Formatted: Font: Bold, Font color: Light Blue
Formatted: Font: Bold, Font color: Light Blue
Formatted: Font: Bold, Font color: Light Blue
Formatted: Indent: Left: 0.5"
Formatted: Font: Bold, Font color: Blue
Formatted: Bulleted + Level: 1 + Aligned at: 0.25" + Tab after: 0.5" + Indent at: 0.5"
Formatted: Bullets and Numbering
Formatted: Underline
Formatted: Indent: Left: 0.5"
Formatted: Underline
Formatted: Font: Bold

- **State Regulations**

California Environmental Quality Act (CEQA)
CEQA applies to projects undertaken by a public agency, funded by a public agency, or requires an issuance of a permit by a public agency. A "project" means the whole of an action that has a potential for resulting in physical change to the environment, and is an activity that may be subject to several discretionary approvals by government agencies. A project is exempt from CEQA if by statute, if considered ministerial or categorical, where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment.

The CPP project is subject to CEQA as there are no applicable exemptions. The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. Accordingly, SCPPA filed an AFC (07-AFC-9) for the project on December 28, 2007. The CEC's 12-month licensing process is a certified regulatory program under CEQA. Thus, the CEC is the lead agency.

- **Federal Regulations**

<u>*40 CFR Part 51—Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart Z—Provisions for Implementation of PM2.5 National Ambient Air Quality Standards, Appendix S to Part 51—Emission Offset Interpretative Ruling*</u>

On May 16, 2008, the USEPA released their final NSR rule for $PM_{2.5}$ and published it in the Federal Register. The effective date of the Final NSR Rule for $PM_{2.5}$ is July 15, 2008. The Final Rule specifies that for areas which are non-attainment for $PM_{2.5}$ NAAQS, the state and local agencies must adopt and submit non-attainment NSR rules to implement the $PM_{2.5}$ requirements for EPA's approval into the State Implementation Plan no later than July 11, 2011. Moreover, in $PM_{2.5}$ non-attainment areas such as the South Coast Air Basin, the permitting agencies must implement the requirements of NSR for $PM_{2.5}$ through Appendix S to Part 51 of Title 40 of the Code of Federal Regulations. Appendix S is the "Emission Offset Interpretive Ruling," which is the rule used for NSR implementation in non-attainment areas.

As of July 15, 2008, all District permit applications for facilities with $PM_{2.5}$ emissions must be evaluated for compliance with $PM_{2.5}$ requirements that are included in Appendix S. The requirements of Appendix S will not apply to facilities if the facility emissions, including existing equipment and equipment currently proposed, will result in a potential to emit of less than 100 tons of $PM_{2.5}$ per year.

Tables ~~26 and 27~~3 above indicate the facility-wide emissions for PM_{10} will be ~~3.997~~ 7.18 tpy for ~~both the commissioning year and~~ a normal operating year. Assuming $PM_{2.5}$ is equal to PM_{10}, the potential for $PM_{2.5}$ will be less than the 100 tpy threshold. *Thus, this provision is **not** applicable to CPP.*

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Formatted: Font: Italic

Formatted: Font: Italic, No underline

<u>*40 CFR Part 60 Subpart GG--NSPS for Stationary Gas Turbines*</u>

Subpart GG is applicable to turbines with a heat input greater than 10 MMBtu/hr (10.7 gigajoules per hour). As the CTGs are subject to the requirements of 40 CFR Subpart KKKK (see below), they are exempt from the requirements of this subpart per §60.4305(b).

<u>*40 CFR Part 60 Subpart IIII--NSPS for Stationary Compression Ignition Internal Combustion Engines*</u>

§60.4200(a)—The provision of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) engines as specified in paragraphs (a)(1) through (a)(3) of this section. §60.4200(a)(2)(i) specifies this subpart is applicable to owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are manufactured after April 1, 2006 and are not fire pump engines. Therefore, this subpart is applicable to the black start engine.

§60.4205(b)—Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE. Since the black start engine has a displacement of 27 liters, §60.4202 is applicable.

§60.4202(a)—Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section. §60.4202(a)(2) provides that for engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

> 40 CFR 89.112—Exhaust emission from nonroad engines shall not exceed the applicable exhaust standards in Table 1 of this provision. As the black start engine is rated at 750 kW, the emission standards in Table 1 for kW > 560 are applicable. Table 1 provides that for Tier 2, the emission standards are 6.4 g/kW-hr for NMHC + NOx, 3.5 g/kW-hr for CO, and 0.20 g/kW-hr for PM. These limits are the same as the District BACT standards. Since CARB has certified in Executive Order U-R-001-0286 that the black start engine will meet these Tier 2 emission standards, the engine will be in compliance with the emissions standards of Subpart IIII.

§60.4209(a)—A non-resettable hour meter is required. Condition no. D12.5 requires a non-resettable elapsed time meter.

§60.4209(b)—If the engine is equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached. Condition no. E193.3 requires a backpressure monitor and an audible alarm.

<u>40 CFR Part 60 Subpart KKKK-- NSPS for Stationary Gas Turbines</u>
Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on higher heating value, which commenced construction, modification or reconstruction after February 18, 2005. As the heat input for each CTG will be 479 MMBtu/hr, this subpart is applicable. Compliance is required by condition H23.1.

> §60.4320(a)--For a natural-gas fired turbine, with a heat input ≥ 50 MMBtu/hr and < 850 MMBtu/hr, the NOx emission limit is 25 ppmv @ 15% O_2 from Table 1 of this subpart. Since the CTGs will meet the BACT limit of 2.5 ppmv @ 15% O_2, compliance with this section is expected.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

§60.4330(a)(2)--To meet the sulfur dioxide emission limit, the turbine exhaust gas shall not contain SO2 in excess of 0.90 lbs/MWh gross output, or the fuel shall not contain total potential sulfur emissions in excess of 0.060 lb SO2/MMBtu heat input. The 0.90 lbs/MWh is a stack limit that requires annual source testing to verify. The 0.06 lb/MMBtu is a fuel based limit which will require fuel sampling, or fuel supplier data.

The applicant has selected the 0.06 lb SO2/MMBtu standard and submitted a Southern California Gas Company (SCGC) document to verify compliance. The SCGC document provided test analysis for out of state suppliers for 2007. A footnote states: "SoCalGas Specifications allow up to 0.25 gr H_2S/100 scf and **0.75 gr. S/100 scf total sulfur.**"

To convert 0.75 gr S/100 scf to units of lb SO_2/MMBtu--

(0.75 gr S/100 ft^3) (1 lb/7000 gr) (ft^3/913 Btu [LHV])
(1 E+06 Btu/MMBtu) (64 lb SO_x/32 lb S)

= 0.0023 lb SO_2/MMBtu < 0.06 lb SO2/MMBtu limit

Thus the CTGs are expected to be in compliance with this section.

§60.4335—To demonstrate compliance for NOx if water injection is used, fuel consumption and water to fuel ratio are required to be monitored and recorded on a continuous basis, or alternatively, a certified NOx and O2 CEMS is required to be installed. For this project, monitoring will be accomplished with a certified CEMS.

§60.4340—For any turbine that uses SCR to reduce NOx emissions, the appropriate parameters must be continuously monitored to verify the proper operation of the emission controls.

§60.4345—This subsection sets forth the requirements for the CEMS. An alternative is that a NOx diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter (Acid Rain) is acceptable for used under this subpart.

§60.4360—The total sulfur content of the fuel being fired in the turbine must be monitored using total sulfur methods described in §60.4415, except as provided in §60.4365.

§60.4365—An election not to monitor the total sulfur content of the fuel combusted in the turbine may be made, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input for units located in continental areas. Two sources of information may be used to make the required demonstration: (1) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for natural gas use in continental areas is 20 grains of sulfur of less per 100 standard cubic feet, has potential sulfur emissions of less than 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas, or (2) Representative fuel sampling data which show the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO2/MMBtu). The applicant will use option one to demonstrate compliance.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

40 CFR Part 63 Subpart YYYY--NESHAPS for Stationary Gas Turbines

This regulation applies to gas turbines located at major sources of HAP emissions. A major source is defined as a facility with emissions of 10 tpy or more of a single HAP or 25 tpy or more of a combination of HAPs. As indicated in Table 28B above, the largest single HAP emission is formaldehyde from the four turbines at ~~0.242~~ 0.436 tpy, which is less than 10 tpy. As indicated in Table 28A above, the total combined HAPs from all sources are ~~0.451~~0.813 tpy, which is less than 25 tpy. *Therefore, the CPP is not a major source, and the requirements of this regulation do not apply.*

Formatted: Font: Italic

Formatted: Font: Italic, No underline

Formatted: No underline

40 CFR Part 63 Subpart ZZZZ--NESHAPS for Stationary Reciprocating Internal Combustion Engines

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. An "affected source" is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand. An "area source" is defined as a source that is not a major source. As discussed above under Subpart YYYY, CPP is not a major source and thus is an area source for HAPs.

§63.6590(a)(2)(iii) provides a stationary RICE located at an area source of HAP emissions is new if construction of the stationary RICE is commenced on or after June 12, 2006.

§63.6590 (c) provides an affected source that is a new RICE located at an area source must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart III for compression ignition engines or 40 CFR part 60 subpart JJJJ for spark ignition engines. No further requirements apply for such engines under this part. Since the black start engine is a new compression-ignition RICE located at an area source, it is required to meet 40 CFR Part 60 Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. (See discussion on Subpart IIII, above.)

(EPA will propose a future NESHAPS that may be applicable to this type of engine located at an area source, but the proposed rule language is not available at this time.)

40 CFR Part 64 – Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) rule, 40 CFR Part 64, specifies the monitoring, reporting, and recordkeeping criteria that is required to be conducted by Title V facilities to demonstrate ongoing compliance with emission limitations and standards.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

In general, CAM applies to emissions units that meet all of the following conditions:

- the unit is located at a major source for which a Title V permit is required: and
- the unit is subject to an emission limitation or standard; and
- the unit uses a control device to achieve compliance with a federally enforceable limit or standard; and
- the unit has potential pre-control emissions (Title V renewal) or post-control emissions (initial Title V or revision) of at least 100% of the major source amount; and
- the unit is not otherwise exempt from CAM.

The CTGs are located at a major source for which a Title V permit is required. The NOx and CO emissions are subject to BACT limits and other emissions standards. Each CTG is controlled with SCR and CO catalyst to meet BACT limits. For each CTG, the post-control NOx and CO emissions, however, are less than the major source thresholds. Specifically, the NOx emissions (commissioning year) is ~~3.32~~ 4.87 tpy, which is less than the 10 tpy threshold. The CO emissions is ~~2.86~~4.19 tpy (commissioning year), which is less than the 50 tpy threshold. (See Table 21 for maximum commissioning year emissions.) Thus, the CAM regulations are not applicable.

40 CFR Part 68—Chemical Accident Prevention Programs
§68.1—This part sets forth the list of regulated substances and thresholds and the requirements for owners or operators of stationary sources concerning the prevention of accidental releases.

§68.10(a)—An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process shall comply with the requirements of this part.

§68.130(a)—Regulated toxic and flammable substances are listed with the associated threshold quantities in Tables 1, 2, 3, and 4 to §68.130. Table 1 to §68.130—List of Regulated Toxic Substances and Threshold Quantities for Accidental Release Prevention [Alphabetical Order—77 Substances] listed "ammonia (anhydrous)" with a threshold quantity of 10,000 lbs, and "ammonia (conc 20% or greater)" with a threshold quantity of 20,000 lbs.

Because the ammonia tank will contain 19% ammonia, not anhydrous ammonia or ammonia with a 20% or greater concentration, Part 68 is not applicable. Therefore, facility condition F24.1, which requires compliance with the accidental release prevention requirements pursuant to 40 CFR Part 68, is not applicable.

Formatted: Underline, Font color: Orange

Regulation XXXI—Acid Rain Permit Program
40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 - Acid Rain Provisions

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

Acid Rain provisions are designed to control SO2 and NOx emissions that could form acid rain from fossil fuel fired combustion devices in the electricity generating industry.

District Regulation XXXI states that the provisions of the regulation apply to the owner or operator of any stationary source for which an acid rain permit is required under this Regulation and lists the Part 72 subparts.

The federal Title 40 CFR parts are as follows: Part 72—Permits Regulation, Part 73—Sulfur Dioxide Allowance System, Part 74—Sulfur Dioxide Opt-Ins, Part 75—Continuous Emissions Monitoring, Part 76—Acid Rain Nitrogen Oxides Emission Reduction Part 77—Excess Emissions, and Part 78—Appeal Procedures for Acid Rain Program.

§72.6--A facility is an affected source subject to the requirements of the federal acid rain program if it includes any affected unit. §72.6(a)(3)(i) includes a "new unit" as an affected unit. §72.2 sets forth definitions. A "unit" means a fossil fuel-fired combustion device. An "affected unit" includes a utility unit that is a new unit. A "utility unit" includes a unit owned or operated by a utility that serves a generator in any state that produces electricity for sale. A "new unit" means "a unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25 MW or less or that is a simple combustion turbine."

§72.7--This provides a "new units exemption" if the unit serves one or more generators with total nameplate capacity of 25 MW or less, does not burn any coal or coal-derived fuel, and burns gaseous fuel with an annual average sulfur content of 0.05 percent or less by weight. **CPP will be subject to the requirements of the federal acid rain program, because the four CTGs are units that each serve generators rated over 25 MW.**

Some of the acid rain program requirements are summarized below:

§72.9—Standard Requirements
The designated representative shall submit a complete Acid Rain permit application, and the owner/operator shall have an Acid Rain Permit. The owner/operator shall comply with the monitoring requirements as provided in part 75 of this chapter (Continuous Emissions Monitoring). The emissions measurements recorded and reported in accordance with part 75 shall be used to determine compliances with the Acid rain emissions limitations and emission reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. The owner/operator shall hold allowances, as of the allowance transfer deadline, in the sources's compliance account (after deductions under §73.34(c) of this chapter) for the previous calendar year from the affected units at the source and comply with the applicable Acid Rain emissions limitations for sulfur dioxide. The owners/operators shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

§72.30—Requirement to Apply

For any source with a new unit under §72.6(a)(3)(i), the designated representations shall submit a complete Acid Rain permit application at least 24 months before the unit begins to serve a generator with a nameplate capacity greater than 25 MW.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

§72.70—Relationship to Title V Operating Permit Program
Subsection (b) states that each State permitting authority with an affected source shall act in accordance with this part and parts 70, 74, 76, and 78 of this chapter for the purpose of incorporating Acid Rain Program requirements into each affected source's operating permit. For each CTG, the facility permit has listed under "Emissions and Requirements" that the SO_2 emission limit is governed by 40CFR 72—Acid Rain Provisions. Also, Section K condition 15(C) provides that nothing in this permit or in any permit shield can alter or affect the applicable requirements of the Acid Rain Program, Regulation XXXI.

§73.10—Initial Allocations for Phase I and Phase II
The acid rain program is similar to RECLAIM in that facilities are required to cover SO2 emissions with "SO2 allowances" that are similar in concept to RTCs. New facilities such as CPP are required to purchase SO2 credits on the open market to cover their annual SO2 releases, since there are no initial allowance allocations.

§75.1—The purpose of part 75 is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO2), nitrogen oxides (NOx), and carbon dioxide (C(2) emissions, volumetric flow, and opacity data.

§75.3(b)(2)—In accordance with §75.20, the owner or operator of each new affected unit shall ensure that all monitoring systems required under this part for monitoring of SO2, NOx, CO2, opacity, and volumetric flow are installed and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences commercial operation, notice of which date shall be provided under subpart G of this part.

§75.10(a)(2)—To determine NOx emissions, the owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of part 75, a NOx-diluent CEMS with an automated data acquisition and handling system, excepted as provided in §§75.12, 75.17 and subpart E. §75.12(d) provides specific provisions and alternatives for monitoring NOx emission rate for gas-fired peaking units.

§75.11(d)—This provides specific provisions for monitoring SO2 emissions for gas-fired units. Instead of a CEMS, the application may elect to use the procedures in appendix D to this part for estimating hourly SO_2 mass emissions. Appendix D to Part 75—Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units requires the use of fuel flowmeters. Further, for each type of gaseous fuel, the appropriate sampling frequency and the sulfur content and gross caloric values used for calculations of SO2 mass emission rates are summarized in Table D-5 of the Appendix.

Formatted: Tab stops: 5.5", Left + Not at 3" + 6"

§75.64--NOx and SOx emissions are required to be electronically reported to the Administrator quarterly.

§76.1--Applicability for Acid Rain Nitrogen Oxides Emission Reduction Program These provisions are applicable to coal-fired units only.

RECOMMENDATION:

Following the conclusion of the required ~~public notice and EPA review periods~~ CEC, Title V and Rule 212(g) agency review and public notice periods and subject to any comments received during this period, I recommend issuing the Permits to Construct for the project in the form of an initial RECLAIM/Title V facility permit, subject to the conditions set forth above.

Page 58: [1] Formatted Vicky Lee 1/28/2009 3:58:00 PM

Tab stops: 5.5", Left + Not at 3" + 6"

Page 111: [2] Change Vicky Lee 2/19/2009 8:18:00 AM

Formatted Table

Page 114: [3] Formatted Vicky Lee 4/16/2009 10:26:00 AM

Underline, Font color: Red

Page 114: [4] Formatted Vicky Lee 4/16/2009 10:26:00 AM

Underline, Font color: Red

Page 114: [5] Formatted Vicky Lee 4/16/2009 10:26:00 AM

Underline, Font color: Red

Page 114: [6] Formatted Vicky Lee 4/16/2009 10:26:00 AM

Underline, Font color: Red

Page 114: [7] Formatted Vicky Lee 4/16/2009 10:26:00 AM

Underline, Font color: Red

Page 114: [8] Formatted Vicky Lee 4/16/2009 10:26:00 AM

Underline, Font color: Red

Page 114: [9] Formatted Vicky Lee 4/16/2009 10:26:00 AM

Underline, Font color: Red

Page 114: [10] Formatted Vicky Lee 4/16/2009 10:27:00 AM

Underline, Font color: Red

Page 114: [11] Formatted Vicky Lee 4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 114: [12] Formatted Vicky Lee 4/16/2009 10:31:00 AM

Underline, Font color: Red

Page 114: [13] Formatted Vicky Lee 4/16/2009 10:18:00 AM

Font color: Red

Page 114: [14] Formatted Vicky Lee 4/16/2009 10:18:00 AM

Font color: Red

Page 114: [15] Formatted Vicky Lee 4/16/2009 10:18:00 AM

Font color: Red

Page 114: [16] Formatted Vicky Lee 4/16/2009 10:27:00 AM

Underline, Font color: Red

Page 114: [17] Formatted Vicky Lee 4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 114: [18] Formatted Vicky Lee 4/16/2009 10:31:00 AM

Underline, Font color: Red

Page 114: [19] Formatted Vicky Lee 4/16/2009 10:27:00 AM

Underline, Font color: Red

Page 114: [20] Formatted Vicky Lee 4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 114: [22] Formatted	Vicky Lee	4/16/2009 10:28:00 AM

Underline, Font color: Red

Page 114: [23] Formatted	Vicky Lee	4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 114: [24] Formatted	Vicky Lee	4/16/2009 10:31:00 AM

Underline, Font color: Red

Page 114: [25] Formatted	Vicky Lee	4/16/2009 10:28:00 AM

Underline, Font color: Red

Page 114: [26] Formatted	Vicky Lee	4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 114: [27] Formatted	Vicky Lee	4/16/2009 10:31:00 AM

Underline, Font color: Red, Not Superscript/ Subscript

Page 115: [28] Formatted	Vicky Lee	4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 58: [29] Formatted	Vicky Lee	1/28/2009 3:58:00 PM

Tab stops: 5.5", Left + Not at 3" + 6"

Page 111: [30] Change	Vicky Lee	2/19/2009 8:18:00 AM

Formatted Table

Page 115: [31] Formatted	Vicky Lee	4/16/2009 10:28:00 AM

Underline, Font color: Red

Page 115: [32] Formatted	Vicky Lee	4/16/2009 10:33:00 AM

Underline, Font color: Red

Page 115: [33] Formatted	Vicky Lee	4/16/2009 10:28:00 AM

Underline, Font color: Red

Page 115: [34] Formatted	Vicky Lee	4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 115: [35] Formatted	Vicky Lee	4/16/2009 10:33:00 AM

Underline, Font color: Red

Page 115: [36] Formatted	Vicky Lee	4/16/2009 10:28:00 AM

Underline, Font color: Red

Page 115: [37] Formatted	Vicky Lee	4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 115: [38] Formatted	Vicky Lee	4/16/2009 10:33:00 AM

Underline, Font color: Red

Page 115: [39] Formatted	Vicky Lee	4/16/2009 10:28:00 AM

Underline, Font color: Red

Page 115: [40] Formatted	Vicky Lee	4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 115: [41] Formatted	Vicky Lee	4/16/2009 10:33:00 AM

Underline, Font color: Red

Page 115: [43] Formatted **Vicky Lee** **4/16/2009 10:18:00 AM**
Font color: Red

Page 115: [44] Formatted **Vicky Lee** **4/16/2009 10:18:00 AM**
Font color: Red

Page 115: [45] Formatted **Vicky Lee** **4/16/2009 10:28:00 AM**
Underline, Font color: Red

Page 115: [46] Formatted **Vicky Lee** **4/16/2009 10:19:00 AM**
Font color: Red, Strikethrough

Page 115: [47] Formatted **Vicky Lee** **4/16/2009 10:33:00 AM**
Underline, Font color: Red

Page 115: [48] Formatted **Vicky Lee** **4/16/2009 10:28:00 AM**
Underline, Font color: Red

Page 115: [49] Formatted **Vicky Lee** **4/16/2009 10:19:00 AM**
Font color: Red, Strikethrough

Page 115: [50] Formatted **Vicky Lee** **4/16/2009 10:34:00 AM**
Underline, Font color: Red

Page 115: [51] Formatted **Vicky Lee** **4/16/2009 10:29:00 AM**
Underline, Font color: Red

Page 115: [52] Formatted **Vicky Lee** **4/16/2009 10:19:00 AM**
Font color: Red, Strikethrough

Page 115: [53] Formatted **Vicky Lee** **4/16/2009 10:34:00 AM**
Underline, Font color: Red

Page 115: [54] Formatted **Vicky Lee** **4/16/2009 10:29:00 AM**
Underline, Font color: Red

Page 115: [55] Formatted **Vicky Lee** **4/16/2009 10:19:00 AM**
Font color: Red, Strikethrough

Page 115: [56] Formatted **Vicky Lee** **4/16/2009 10:34:00 AM**
Underline, Font color: Red

Page 115: [57] Formatted **Vicky Lee** **4/16/2009 10:29:00 AM**
Underline, Font color: Red

Page 115: [58] Formatted **Vicky Lee** **4/16/2009 10:19:00 AM**
Font color: Red, Strikethrough

Page 115: [59] Formatted **Vicky Lee** **4/16/2009 10:34:00 AM**
Underline, Font color: Red

Page 115: [60] Formatted **Vicky Lee** **4/16/2009 10:29:00 AM**
Underline, Font color: Red

Page 115: [61] Formatted **Vicky Lee** **4/16/2009 10:19:00 AM**
Font color: Red, Strikethrough

Page 115: [62] Formatted **Vicky Lee** **4/16/2009 10:34:00 AM**
Underline, Font color: Red

Page 115: [64] Formatted Vicky Lee 4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 115: [65] Formatted Vicky Lee 4/16/2009 10:34:00 AM

Underline, Font color: Red

Page 115: [66] Formatted Vicky Lee 4/16/2009 10:29:00 AM

Underline, Font color: Red

Page 116: [67] Formatted Vicky Lee 4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 116: [68] Formatted Vicky Lee 4/16/2009 10:34:00 AM

Underline, Font color: Red

Page 116: [69] Formatted Vicky Lee 4/16/2009 10:18:00 AM

Font color: Red

Page 116: [70] Formatted Vicky Lee 4/16/2009 10:18:00 AM

Font color: Red

Page 116: [71] Formatted Vicky Lee 4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 58: [72] Formatted Vicky Lee 1/28/2009 3:58:00 PM

Tab stops: 5.5", Left + Not at 3" + 6"

Page 111: [73] Change Vicky Lee 2/19/2009 8:18:00 AM

Formatted Table

Page 116: [74] Formatted Vicky Lee 4/16/2009 10:30:00 AM

Underline, Font color: Red

Page 116: [75] Formatted Vicky Lee 4/16/2009 10:34:00 AM

Underline, Font color: Red

Page 116: [76] Formatted Vicky Lee 4/16/2009 10:18:00 AM

Font color: Red

Page 116: [77] Formatted Vicky Lee 4/16/2009 10:30:00 AM

Underline, Font color: Red

Page 116: [78] Formatted Vicky Lee 4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 116: [79] Formatted Vicky Lee 4/16/2009 10:34:00 AM

Underline, Font color: Red

Page 116: [80] Formatted Vicky Lee 4/16/2009 10:30:00 AM

Underline, Font color: Red

Page 116: [81] Formatted Vicky Lee 4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 116: [82] Formatted Vicky Lee 4/16/2009 10:35:00 AM

Underline, Font color: Red

Page 116: [83] Formatted Vicky Lee 4/16/2009 10:30:00 AM

Underline, Font color: Red

Page 116: [85] Formatted	Vicky Lee	4/16/2009 10:35:00 AM

Underline, Font color: Red

Page 116: [86] Formatted	Vicky Lee	4/16/2009 10:30:00 AM

Underline, Font color: Red

Page 116: [87] Formatted	Vicky Lee	4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 116: [88] Formatted	Vicky Lee	4/16/2009 10:35:00 AM

Underline, Font color: Red

Page 116: [89] Formatted	Vicky Lee	4/16/2009 10:30:00 AM

Underline, Font color: Red

Page 116: [90] Formatted	Vicky Lee	4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 116: [91] Formatted	Vicky Lee	4/16/2009 10:35:00 AM

Underline, Font color: Red

Page 116: [92] Formatted	Vicky Lee	4/16/2009 10:30:00 AM

Underline, Font color: Red

Page 116: [93] Formatted	Vicky Lee	4/16/2009 10:19:00 AM

Font color: Red, Strikethrough

Page 116: [94] Formatted	Vicky Lee	4/16/2009 10:35:00 AM

Underline, Font color: Red

Page 116: [95] Formatted	Vicky Lee	4/16/2009 10:52:00 AM

Font color: Red, Strikethrough

Page 116: [96] Formatted	Vicky Lee	4/16/2009 10:53:00 AM

Font color: Red, Strikethrough

June 24, 2009

Eric Solorio, Project Manager
California Energy Commission
Siting, Transmission and Environmental Protection Division
1516 Ninth Street, MS-15
Sacramento, CA 95814-5512

Subject: Final Determination of Compliance (FDOC) for Canyon Power Plant (CPP) Proposed 200 Megawatt Power Plant Project (Facility ID No. 153992), to be located at 3071 E. Miraloma Avenue, Anaheim, CA 92805 (07-AFC-9)

Dear Mr. Solorio:

This is in reference to the City of Anaheim's Canyon Power Plant (CPP) proposed Power Plant Project Application for Certification (AFC) and Title V Application for a Permit to Construct filed with the California Energy Commission (CEC) and the South Coast Air Quality Management District (AQMD), respectively. As you know, the City of Anaheim has proposed to construct a 200 megawatt (MW) power plant, located at 3071 E. Miraloma Avenue, Anaheim, CA 92805.

On February 25, 2009 the AQMD issued the Preliminary Determination of Compliance (PDOC) to the CPP project. At this time the AQMD has conducted further analysis of the project and considered all comments received during the comment period. Based on our evaluation, AQMD is issuing a Final Determination of Compliance (FDOC) indicating CPP complies with all applicable air quality Rules and Regulations and other AQMD requirements, including emissions offsets requirements of AQMD Rule 1303(b)(2). The purpose of this letter is to transmit our evaluation and the FDOC to CEC and to list the revisions which will be made to the PDOC issued on February 25, 2009, based on our further analysis and comments the AQMD has received from both CEC and the City of Anaheim. The USEPA did not provide comments.

In addition, please note that Attachment A is a summary of the additional minor revisions based on comments received from CEC which will be reflected in the FDOC. Attachment B is a summary of the AQMD's comments on the Preliminary Staff Assessment.

If you have any questions regarding this project, please contact Mr. John Yee at (909) 396-2531 jyee@aqmd.gov. For any questions regarding this letter and the FDOC, please contact Mr. Michael D. Mills, Senior Manager at (909) 396-2578 mmills@aqmd.gov.

Sincerely,

Mohsen Nazemi, P.E.
Deputy Executive Officer
Engineering and Compliance

MN:MDM:vl

cc: Steve Sciortino, City of Anaheim
Scott A. Galati, Galati Blek LLP
Barry Wallerstein, AQMD (w/o enclosures)
Kurt Wiese, AQMD (w/o enclosures)
Barbara Baird, AQMD (w/o enclosures)
Mike Mills, AQMD (w/o enclosures)

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

(FDOC Cover Letter)

ATTACHMENT A

RESPONSE TO COMMENTS FROM THE CEC ON THE PRELIMINARY DETERMINATION OF COMPLIANCE

Comments on PDOC Conditions

1. Facility Conditions – CEC stated that Condition K67.5 in Section D should also be placed in Section H of the Facility Permit similar to Facility Conditions F9.1, F14.1 and F24.1.
   Conditions F9.1, F14.1, and F24.1 are facility conditions, which apply to the entire facility and thus appear automatically in both Sections D and H. Condition K67.5 is a device condition that applies to device E30 only. Device E30 is included in Section D only; thus, condition K67.5 appears in Section D only.

2. Facility Conditions – CEC stated that 40CFR Part 68 referenced in Condition F24.1 does not apply to this project and should be deleted.
   AQMD staff agrees and Condition F24.1 will be deleted from the facility permit.

3. Condition A63.2 – CEC stated that this condition should be removed
   Condition A63.2 was appropriately removed from the PDOC when the scope of the project changed, but inadvertently left on the facility permit. Condition A63.2 will be deleted from the facility permit.

4. Condition E193.1 – CEC stated that this condition should not be incorporated into the Staff Assessment as CEC believes the condition is redundant.
   AQMD believes this condition is not redundant and will continue to require the condition as part of the Title V Facility Permit and the words "air quality" will not be removed from condition E193.1.

5. Condition D29.2 – CEC stated that to be consistent with Condition K40.1, the time frame for source test submittal should be changed to 60 days.
   Condition D29.2 will be revised to require the ammonia source test results to be submitted to the AQMD within 60 days after the test date rather than 45 days.

6. Condition I296.1 and I296.2 RTC Zone Designation – CEC requests the addition of Zone 1 to the permit conditions.
   The comment suggests that the term "Zone 1" be added to these two conditions to clarify that only Zone 1 RTCs are allowed for this facility. On the facility permit, Section A: Facility Information already specifies the zone is "coastal," which is the same as Zone 1. (The zone designation is "inland" for zone 2.) Consequently, there is no need to repeat the requirement in the conditions I296.1 and I296.2. Further, the AQMD's RECLAIM administration team implements the RTC trades and ensures the RTCs are from the correct zone.

7. Conditions A99.1 and A195.1 – CEC stated that the NOx Emission Concentration Limit should be changed to 2.3 ppmv
   The comment states that the NOx emission concentration limit noted in these two conditions should be 2.3 ppm, as stipulated to by the applicant and used by the District in

the NOx emissions and RTC requirement calculations, rather than the 2.5 ppm value shown in these two conditions. These two conditions are based on 2.5 ppm, because that remains the BACT/LAER limit which is the maximum NOx emission concentration, averaged over one hour, which the turbines are required to not exceed.

The 2.3 ppm is used in the NOx emissions and RTC requirement calculations because the NOx emissions concentration averaged over one year is expected to be lower than the 2.5 ppm hourly average limit. The 2.3 ppm is guaranteed by the turbine manufacturer and expected to provide a reasonable estimate of the actual emission increase.

Comments on Engineering Evaluation

8. Rule 1304 Offset Exemption Discussion – CEC stated that AQMD is inconsistent in its implementation of the Superior Court decision concerning use of Rule 1304 exemptions and that Rule 1304 (d)(3) is being applied to the water cooling towers
The first comment is that, although the PDOC states the District cannot issue permits using any Rule 1304 offset exemptions pursuant to a Superior Court decision, the Rule 1304(d)(3) offset exemption appears to have been applied to the cooling tower PM_{10} emissions. The NSR requirements, including offsets requirements, do not apply to the cooling tower because NSR requirements only apply to permitted equipment. The cooling tower is exempt from permitting pursuant to Rule 219(d)(3). Therefore, an offset exemption is not applicable.

On page 61, under *Offset Requirements/NSR Entries*, the PDOC states: "Rule 1303(b)(2) requires a net emission increase in emissions of any nonattainment air contaminant from a new source to be offset unless exempt from offset requirements pursuant to Rule 1304." To provide clarification, the following will be inserted: "'Source' is defined by Rule 1302(ao) to mean "any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air contaminant. This includes any permit unit at any non-RECLAIM facility and any device at a RECLAIM facility."

The second comment is that the basis of the offset calculation for the emergency engine should be changed from the 52 hours of operation used in the PDOC to the permitted 200 hours, the same as was used for the RECLAIM credit calculation. For non-RECLAIM facilities, the District policy is to use 50 hours of operation (or 52 hours to simplify the operating schedule) for the offset calculations, including for NOx, because the NSR rules in Regulation XIII do not specify a basis for the operating schedule. For RECLAIM facilities, Rule 2005(d) specifies the RECLAIM credit calculation shall be based on the potential to emit or on a permit condition limiting the source's emissions. Thus, the RECLAIM credit calculation was based on 200 hours pursuant to the limit set by condition C1.1.

9. Page 46 – Table 10 – CEC statess that the NOx and SO_2 Average Emission Rates are not consistent and do not reflect the levels stipulated by the applicant
The first comment is that the average NOx emission rates presented in PDOC Table 10 were not the final applicant stipulated values. Accordingly, the AQMD followed up with the applicant. The applicant characterized the outdated values as a text error and

provided the correct values on 4/21/09. PDOC Table 10 and the NOx emissions and RTC requirement calculations have been revised to reflect the corrected values.

The second comment is that the worse-case short-term SO2 emissions should be based on the SoCalGas sulfur CPUC tariff sheet limit value of 0.75 grains/100 scf, instead of the 1.0 grains/100 scf. As the 1.0 grains/100 scf was used for modeling only, not emissions calculations, the minor overestimate provided conservative modeling results.

10. <u>Page 61 to 71 – CEC stated that the AQMD Offset Requirements/NSR Entries which use rounding procedures propagates errors in determining the offset requirements.</u> This comment suggested that the AQMD determine offsets requirements on a facility-wide basis instead of a permit unit basis. The AQMD has determined offsets requirements for this project on a facility project basis.

ATTACHMENT B

AQMD COMMENTS ON THE PRELIMINARY STAFF ASSESSMENT

1. Pg. 4.1-3: Air Quality Table 1--Laws, Ordinances, Regulations, and Standards (LORS)
For 40 CFR 60 Subpart KKKK, Air Quality Table 1 indicates the NOx emissions limit is 15 ppm at 15% O_2. According to Table 1 to Subpart KKKK of Part 60, the NOx emission standard is 25 ppm at 15% O2 for a new turbine firing natural gas, with a heat input at peak load > 50 MMBtu/h and ≤ 850 MMBtu/h.

2. Pg. 4.1-21: Air Quality Table 13—SCAQMD 30-Day Average Daily Emissions (lbs/day per turbine)
Air Quality Table 13 indicates the SCAQMD 30-Day Average for SO2 is 1.44 lb/day. The 30-day average is 1.2 lb/day, as indicated on pg. 64 of the PDOC. The 1.44 lb/day value is the product of the 1.2 lb/day multiplied by the 1.2 offset ratio.

3. Pg. 4.1-30: Applicant's Proposed Mitigation, Emissions Controls
The PSA states the PDOC conditions provide that the BACT emissions limit for NOx is 2.3 ppmvd at 15% O_2. Table 31—Simple Cycle Gas Turbine MSBACT/LAER Requirements on pg. 81 of the PDOC states the BACT emissions limit for NOx remains 2.5 ppmvd at 15% O_2. Further, conditions A99.1 and A195.1 reflect the 2.5 ppmvd BACT limit.

4. Pg. 4.1-31: Air Quality Table 18—Canyon SCAQMD Offset Requirement Summary (lbs)
Air Quality Table 18 indicates the number of RECLAIM Trading Credits (RTCs) (lbs/year) required for the project is 27,542. Pg. 98 of the PDOC states the number of NOx RTCs required per normal operating year, including the RTCs required for the black start engine, is 30,252. For the FDOC, the number of RTCs will be revised to 29,956 to reflect the correction of the turbine emission rate for NOx from 4.05 lb/hr to 3.98 lb/hr. The correction for the NOx emission rate was received from the CEC and City of Anaheim after the issuance of the PDOC.

5. Pg. 4.1-32: Air Quality Table 20—PM_{10} Offsets Proposed for Canyon
Pg. 4.1-57: Staff Condition AQ-SC7
The credit numbers (certificate numbers) listed in Air Quality Table 20 for the offset source location at 2211 E. Carson St, Long Beach, are for Commonwealth Aluminum Concast (CAC), the originator of the ERCs. The change of ERC owner applications have subsequently been processed by the AQMD. Consequently, CAC certificate nos. AQ008497 – AQ008504 have been converted to CPP certificate nos. AQ009027, AQ009029, AQ009031, AQ009033, AQ009035, AQ009037, AQ009039, AQ009041. CAC certificate nos. In addition, CAC certificate nos. AQ008516 – AQ008523 have been converted to CPP certificate nos. AQ009043, AQ009045, AQ009047, AQ009049, AQ009051, AQ009053, AQ009055, AQ009057. Also, CAC certificate nos. AQ008682 – AQ008689 have been converted to CEC certificate nos. AQ009325, AQ009327, AQ009329, AQ009331, AQ009333, AQ009335, AQ009337, AQ009339. For the FDOC, Table 40C – ERC Certificate Nos. and History will be updated to reflect the processing of the change of ERC owner applications. These same comments apply to staff condition AQ-SC7.

The paragraph following Air Quality Table 20 states the actual offset ratio is 1.21:1 based on maximum annual PM_{10} emissions of 14,536 lbs/yr. Pg. 72 of the PDOC indicate the maximum annual emissions for all four turbines is 14,352 lbs/yr.

6. Pg. 4.1-43—Rule 407-Liquid and Gaseous Air Contaminants
The PSA states the CTGs would meet the BACT limit of 6.0 ppmvd @ 15 percent O2 for CO. Table 31—Simple Cycle Gas Turbine MSBACT/LAER Requirements on pg. 81 of the PDOC states the BACT emissions limit for CO is 4.0 ppmvd at 15% O_2, for this project. The District has sufficient test results for initial and periodic monitoring source testing for LM6000 turbines installed at existing power plants to demonstrate the 4.0 ppmvd to be achieved in practice.

7. Pg. 4.1-46—Regulation XVII-Prevention of Significant Deterioration (PSD)
The PSA states the District is not currently delegated authority for PSD permitting by U.S.EPA. As discussed on pp. 111-112 of the PDOC, on 7/25/07, the EPA and AQMD signed a new "Partial PSD Delegation Agreement."

8. Pg. 4.1-49—Condition A99.1 and A195.1
Pg. 4.1-60—CEC Condition AQ-2 (corresponds to A99.1)
Pg. 4.1-61—CEC Condition AQ-4 (corresponds to A195.1)
The PSA states condition A99.1 provides relief from the 2.3 ppm NOx limit during commissioning, startup and shutdown, and condition A195.1 provides the averaging time for the 2.3 ppm NOx. As stated in the PDOC, conditions A99.1 and A195.1 references the 2.5 ppm NOx BACT limit.

9. Pg. 4.1-60—CEC Condition AQ-3 (corresponds to A99.4 and A99.5)
The FDOC will revise condition A99.5 to reflect the correction of the turbine emission rate for NOx from 4.05 lb/hr to 3.98 lb/hr. The emission limit of 11.65 lbs/MMCF NOx applicable after commissioning will be changed to 11.53 lbs/mmcf.

10. Pg. 4.1-67—CEC Condition AQ-14 (corresponds to I296.1)
The FDOC will revise condition I296.1 to reflect the correction of the turbine emission rate for NOx from 4.05 lb/hr to 3.98 lb/hr. The RTCs required prior to the 1st year will change from 9,746 lbs/yr 9677 lbs/yr. The RTCs required prior to subsequent years will change from 6,960 lbs/yr 6886 lbs/yr.

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 *CANYON POWER PLANT PROJECT*

Docket No. 07-AFC-9

PROOF OF SERVICE
(Revised 2/25/2009)

APPLICANT

Southern California Public Power Authority (SCPPA)
c/o City of Anaheim
Public Utilities Department
Steve Sciortino, Project Manager
201 S. Anaheim Blvd, Suite 802
Anaheim, CA 92805
ssciortino@anaheim.net
swilson@anaheim.net

APPLICANT CONSULTANT

URS Corporation
Cindy Poire, Project Manager
130 Robin Hill Road, Suite 100
Santa Barbara, CA 93117
cindy_poire@urscorp.com

COUNSEL FOR APPLICANT

***Scott Galati**
Galati & Blek, LLP
455 Capitol Mall, Suite 350
Sacramento, CA 95814
sgalati@gb-llp.com

INTERESTED AGENCIES

California ISO
e-recipient@caiso.com

INTERVENORS

ENERGY COMMISSION

JEFFREY D. BYRON
Commissioner and Presiding Member
jbyron@energy.state.ca.us

ARTHUR H. ROSENFELD
Commissioner and Associate Member
arosenfe@energy.state.ca.us

Paul Kramer
Hearing Officer
Pkramer@energy.state.ca.us

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

Deborah Dyer
Staff Counsel
ddyer@energy.state.ca.us

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

Declaration of Service

I, Marie Mills, declare that on June 26, 2009, I served and filed copies of the attached **FINAL DETERMINATION OF COMPLIANCE (FDOC)** dated **June 24, 2009.** The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[www.energy.ca.gov/sitingcases/canyon]**. The document has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

For service to all other parties:

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

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

AND

For filing with the Energy Commission:

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

OR

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

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. **07-AFC-9**
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

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

Marie Mills

Marie Mills