DOCKETED

Docket Number:	08-AFC-09C
Project Title:	Palmdale Energy Project (Formerly Palmdale Hybrid Power Plant) - Compliance
TN #:	211451
Document Title:	Antelope Valley Air Quality Management District's Preliminary Determination of Compliance - Rev A for Palmdale Energy Project
Description:	N/A
Filer:	Marie Fleming
Organization:	DayZen LLC
Submitter Role:	Applicant Representative
Submission Date:	5/12/2016 12:13:54 PM
Docketed Date:	5/12/2016

Antelope Valley
Air Quality Management District

Antelope Valley Air Quality Management District
43301 Division St., Suite 206
Lancaster, CA 93535-4649

661.723.8070
Fax 661.723.3450

Eldon Heaston, Executive Director

May 11, 2016

Thomas Johns
Palmdale Energy, LLC
801 2nd Avenue, Suite 1150
Seattle, WA 98104

RE: Preliminary Determination of Compliance Revision A for the Palmdale Energy Project

Dear Mr. Johns:

The Antelope Valley Air Quality Management District (District) has completed the revised preliminary decision on the proposed Palmdale Energy Project (PEP). This revision incorporates changes derived from comments received on the initial preliminary decision pertaining to technical clarifications, permit conditions, and emission offsets. Enclosed please find the Preliminary Determination of Compliance (PDOC) Revision A for PEP, prepared pursuant to District Rule 1306, *Electric Energy Generating Facilities*.

Written comments concerning the PEP PDOC Revision A will be accepted through June 11, 2016 or thirty days after the date the notice is published (whichever is later). The District, after consideration of any public, State, and EPA comments, expects to issue a Final Determination of Compliance on or about June 24, 2016.

If you have any questions regarding this action or the enclosure, please contact Chris Anderson at (760) 245-1661 extension 1846.

Sincerely,

Bret S. Banks
Air Pollution Control Officer

Enclosure: (PDOC Rev A, Public Notice)

E-mail cc: Eric Veerkamp, CEC (eric.veerkamp@energy.ca.gov)
Gerardo Rios, USEPA Region 9 (R9AirPermits_av_md@epa.gov)
Chief, Stationary Source Division CARB c/o Tung Le (ttle@arb.ca.gov)
Nancy Fletcher, CEC (nancy.fletcher@energy.ca.gov)
Greg Darvin, Atmospheric Dynamics (darvin@atmosphericdynamics.com)

BSB/cja PEP PDOC RevA Cover.doc

Preliminary
Determination of Compliance
Revision A

(Preliminary New Source Review Document)

Palmdale Energy Project
Palmdale, California

Bret Banks
Air Pollution Control Officer

Antelope Valley Air Quality Management District

May 11, 2016

History of Revisions

1. **Sections 3 and 7**- Updated tables 2, 3, and 4 to reflect change in short term sulfur limit from 0.2 to 0.75 gr/100 dscf.
2. **Section 5**- Added subsection addressing state SO_X BACT requirement (for turbines only.) No change to project requirements result as project continues to propose use of clean fuels.
3. **Section 6- Class I Area Visibility Protection**. Removed reference to "PSD" (as EPA is responsible for implementing PSD) from section title and clarified that the District visibility protection analysis consider emissions of federal nonattainment pollutants. Findings continue to be based on original analysis.
4. **Section 9- Offsets**
    a. Confidential Offset Package. The applicant has withdrawn their proposal to maintain confidentiality of the proposed list of NO_x and VOC ERCs. Table 7 was revised to include the proposed ERC sources.
    b. RACT- A section was added to specify the RACT upon use requirement pursuant to Rule 1305(C)(4). The District will adjust any offsets to be used to reflect RACT in effect at time (in outgoing or receiving District) of use if such reductions have not already been made. All of the proposed NOx and VOC ERCs were subject to a RACT adjustment at time of banking.
    c. Area and Indirect Source Offsets (Paving ERCs). Clarified that the AVAQMD will apply the provisions of current AVAQMD rule 1305 to approve/disapprove PM10 (state only) offsets.
    d. Inter-pollutant offsets- the applicant has withdrawn its proposal to use inter-pollutant offsets. This particular subsection has been stricken from document.
    e. NOx ERC from SJVAPCD- the applicant has withdrawn its proposal to use NOx from SJVAPCD. This particular subsection stricken from document.
    f. Paving ERC- Clarified this section to reflect control over each road segment, as required by Rule 1305(B)(3)(d)(ii), is sufficiently demonstrated through the PERC application process.
    g. Timing- For clarification purposes District Rule 1302 requires that offsets must be surrendered prior to beginning actual construction. CTG Permit condition 18 addresses this requirement requiring the sum total of offsets be submitted in accordance with this provision. In addition to avoid confusion the body of text pertaining to offsets was revised to ensure this is clear.
    h. Inter-basin Offsets- revisions to this section to incorporate applicants voluntary use of a distance offset ratio for VOCs from the San Joaquin Valley Air Basin
5. **Section 10- Applicable Regulation and Compliance Analysis**
    a. Updated section to ensure all applicable regulations are included specifically 40 CFR Subpart Db.

   b. Revised Table 3 to include only the max hourly operational emission rates.

6. **Section 12- Permit Conditions**
   a. Revised permit conditions to reflect that BACT applies at all times (by including periods of malfunction as subject to emission limits). CTG Condition 4.
   b. Revised BACT for CTG hourly emission limitations to explicitly state must comply with concentration limits. CTG Condition 4.
   c. Facility wide emission limits revised to include startup, shutdown, malfunction. CTG Condition 6 and 7.
   d. CTG Condition 12 revised to stipulate NH3 monitoring conducted using PEMS (NOx differential method)
   e. CTG Condition 14 revised to specify testing is at least as often as once every three years and allow use of alternative equivalent SO2 source test method and specified test method for NH3 slip.
   f. CTG Condition 16 updated to coincide with the use of PEMS for NH3 monitoring.
   g. CTG Condition 26- added (NH3) PEMS certification to initial compliance test.
   h. SCR Condition 5 revised to specify BACT emission limit will apply during malfunction.
   i. SCR Condition 5 updated with calculation for NH3 slip.
   j. Aux Boiler Condition 4 revised hourly emission limitations to explicitly state must comply with BACT concentration limits and revised emission limitation to include lb/MMBtu emission limitation, consistent with subpart Db.
   k. Added recordkeeping provision to Aux Boiler Condition 6 to ensure compliance with subpart Db.
   l. Added stack height permit requirement to Aux Boiler, Condition 9
   m. Aux Boiler Conditions 10 and 11 added to ensure compliance with subpart Db.
   n. Added citation(s) at the end of each permit condition for the origin of each permit condition (e.g. applicable requirement.)

(this page intentionally left blank.)

Table of Contents

Table of Contents i
List of Abbreviations iii
Background 1
1. Introduction 1
2. Project Location 1
3. Description of Project 1
4. Overall Project Emissions 3
5. Control Technology Evaluation 6
NO_x LAER/BACT 7
CO BACT 8
SO_X BACT 9
PM_{10} and $PM_{2.5}$ BACT 9
VOC LAER/BACT 10
6. Class I Area Visibility Protection 11
Findings 11
Inputs and Methods 11
7. Air Quality Impact Analysis 11
Findings 11
Inputs and Methods 14
8. Health Risk Assessment and Toxics New Source Review 14
Findings 14
Inputs and Methods 15
9. Offset Requirements 15
Required Offsets 15
Reasonably Available Control Technology (RACT) Adjustment 16
Identified Potential Emission Reduction Credits 16
Area and Indirect Source Offsets 17
Inter-District and Inter-Basin Offsetting 18
10. Applicable Regulations and Compliance Analysis 19
Regulation II – Permits 19
Regulation IV – Prohibitions 20
Regulation IX – Standards of Performance for New Stationary Sources 21
Regulation XI – Source Specific Standards 23
Regulation XIII – New Source Review 24
Regulation XIV – Toxics and Other Non-Criteria Pollutants 24
Regulation XII – Prevention of Significant Deterioration 25
Regulation XXX – Federal Operating Permits 25
National Emission Standards for Hazardous Air Pollutants/Maximum Achievable Control Technology Standards 25
11. Conclusion 26
12. Permit Conditions 26
Combustion Turbine Generator Power Block Authority to Construct Conditions 27
HRSG Duct Burner Authority to Construct Conditions 33
Oxidation Catalyst System Authority to Construct Conditions 34

Selective Catalytic Reduction System Authority to Construct Conditions 34
Auxiliary Boiler Authority to Construct Conditions 35
Emergency Generator Authority to Construct Conditions.. 37
Emergency Fire Suppression Water Pump Authority to Construct Conditions 38
Appendix A - PEP Emissions Calculation.. A1
Appendix B- Road Segments Considered for Paving (PM_{10} Reduction) B1

List of Abbreviations

APCO	Air Pollution Control Officer
ATC	Authority To Construct
ATCM	Airborne Toxic Control Measure
AVAQMD	Antelope Valley Air Quality Management District
BACT	Best Available Control Technology
CARB	California Air Resources Board
CATEF	California Air Toxics Emission Factors
CEC	California Energy Commission
CEMS	Continuous Emissions Monitoring System
CERMS	Continuous Emission Rate Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide
CTG	Combustion Turbine Generator
dscf	Dry Standard Cubic Feet
ERC	Emission Reduction Credit
°F	Degrees Fahrenheit (Temperature)
FDOC	Final Determination of Compliance
HAP	Hazardous Air Pollutant
HARP	Hot Spots Analysis and Reporting Program
HDPP	High Desert Power Project
HHV	Higher Heating Value
hp	Horsepower
hr	Hour
HRA	Health Risk Assessment
HRSG	Heat Recovery Steam Generator
HTF	Heat Transfer Fluid
LAER	Lowest Achievable Emission Rate
lb	Pound
MACT	Maximum Achievable Control Technology
$\mu g/m^3$	Micrograms per cubic meter
MDAQMD	Mojave Desert Air Quality Management District
MMBtu	Millions of British Thermal Units
n/a	Not applicable
NAAQS	National Ambient Air Quality Standard
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
O_2	Molecular Oxygen
OEHHA	Office of Environmental Health Hazard Assessment
OLM	Ozone Limiting Method
o/o	Owner/Operator
PAH	Polycyclic Aromatic Hydrocarbons
PDOC	Preliminary Determination of Compliance
PEP	Palmdale Energy Project

$PM_{2.5}$	Fine Particulate, Respirable Fraction ≤ 2.5 microns in diameter
PM_{10}	Fine Particulate, Respirable Fraction ≤ 10 microns in diameter
ppmvd	Parts per million by volume, dry
PSD	Prevention of Significant Deterioration
RSP	Rapid Start Process
SCAQMD	South Coast Air Quality Management District
SJVAPCD	San Joaquin Valley Air Pollution Control District
SCLA	Southern California Logistics Airport
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_x	Oxides of Sulfur
STG	Steam Turbine Generator
TOG	Total Organic Gases
tpy	Tons per Year
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

Background

The AVAQMD received comments from EPA Region IX and the Center for Biological Diversity on the Palmdale Energy Project (PEP) Preliminary Determination of Compliance (PDOC). No comments were received from the California Air Resources Board or the general public. The California Energy Commission commented on the PEP PDOC in their Preliminary Staff Assessment. This revised PDOC seeks to address all comments received or directed at the PEP PDOC. A summary of changes is included in the History of Revisions.

1. Introduction

The Antelope Valley Air Quality Management District (AVAQMD or District) received an Application for New Source Review for the Palmdale Energy Project (PEP or Project) on July 23, 2015. This document represents a revised initial new source review document, or Preliminary Determination of Compliance (PDOC) Revision A, for the proposed project.

As required by AVAQMD Rule 1306(E)(1)(a), this document will review the proposed project, evaluating worst-case or maximum air quality impacts, and establish control technology requirements and related air quality permit conditions. This document represents the preliminary pre-construction compliance review of the proposed project, to determine whether construction and operation of the proposed project will comply with all applicable AVAQMD rules and regulations. A determination of compliance shall confer the same rights and privileges as the new source review document and ATC(s) if and when the CEC approves the AFC, and the CEC certificate includes all conditions contained in the determination of compliance.

2. Project Location

The PEP site is located at 950 East Ave M, Palmdale, California. The project site is located on an approximately 50-acre parcel west of the northwest corner of U.S. Air Force Plant 42, and east of the intersection of Sierra Highway and East Ave M, within the City of Palmdale. The project site has been designated non-attainment for the Federal 8-hour ozone ambient air quality standard (NAAQS) and non-attainment for the California ozone and PM_{10} standards (CAAQS). The area is attainment or unclassified for all other standards and averaging times. The project site is currently undeveloped desert.

3. Description of Project

Palmdale Energy, LLC proposes to construct, own, and operate the PEP, which consists of natural gas-fired combined-cycle generating equipment to be developed on an approximately 50-acre site in the northern portions of the City of Palmdale. The combined-cycle equipment utilizes two natural gas-fired combustion turbine generators (CTG), two heat recovery steam generators (HRSG), one steam turbine generator (STG), and one auxiliary boiler.

The Project will have a nominal electrical output of 645 MW at average annual conditions and commercial operation is planned for summer 2019/summer 2020. The Project will be fueled with natural gas delivered via a new natural gas pipeline. The Southern California Gas Company

(SCG) will design and construct the approximately 8.7-mile pipeline in existing street rights-of-way (ROW) within the City of Palmdale.

The project will have twin Siemens SGT6-5000F gas turbines with dry low NO_x combustors driving dedicated duct burner-equipped HRSGs. Each gas turbine will have a maximum heat input rating of 2,467 million Btu per hour (MMBtu/hr), and each duct burner will have a maximum heat input rating of 193.1 MMBtu/hr. The (two) CTGs and (two) HRSG duct burners will be exclusively fueled by pipeline specification natural gas. The CTG power blocks will each include a turbine air compressor section, gas combustion system combustors, power turbine, and a 60-hertz generator. Inlet air will be filtered and conditioned, with inlet cooling provided by an evaporative type cooling system. Ambient air will be filtered and compressed in a multiple-stage axial flow compressor. Compressed air and natural gas will be mixed and combusted in the turbine combustion chamber. A premixed pilot design coupled with dry low NO_x combustors will be used to minimize NO_x formation during combustion. Exhaust gas from the combustion chamber will then expand through a multi-stage power turbine which drives both the air compressor and the electric power generator. Heat from the exhaust gas will then be recovered in a HRSG.

Each HRSG is a horizontal, natural circulation type unit with three pressure levels of steam generation. A duct burner in each HRSG will provide additional heat through supplemental firing (limited to 1500 hours per year), which enable the HRSG to produce more steam in order to obtain peaking output from the steam turbine. A selective catalytic reduction (SCR) system and high temperature oxidation catalyst will be located within each HRSG. Steam will be produced in each HRSG and flow to the STG. The STG will drive an electric generator to produce electricity. STG exhaust steam will be condensed in an air cooled condenser (ACC).

PEP will employ a fast start plant concept to shorten startup durations through the use of a modified steam drum complex. In support of this process, the project includes a limited use (4,884 hour per year, dependent upon operating scenario) natural gas-fired auxiliary boiler equipped with ultra-low NO_x burners (9 ppmvd) with a maximum heat input rating of 110 MMBtu/hr. The auxiliary boiler will provide sealing steam to steam turbine shaft seals during startup and while shutdown so that condenser vacuum can be achieved or maintained and warming steam to certain steam cycle components to minimize HRSG and STG startup thermal limitations.

Power plant cooling will be provided by an ACC. ACC directly condense exhaust steam from the steam turbine and return condensate to the boiler without water loss. The ACC is a direct dry cooling system where the steam exhaust from the low pressure (LP) turbine section is condensed inside air-cooled finned tubes.

A small amount of emergency electrical power will be provided on site by a 2011 horsepower (hp) (1500 kWe) diesel-fired internal combustion engine and shaft generator.

Emergency fire suppression water pressure will be provided on site by a 140 hp diesel-fired internal combustion engine and shaft water pump.

4. Overall Project Emissions

PEP will produce exhaust emissions during three basic performance modes: startup, operations mode, and shutdown. Turbine emissions estimates are based on manufacturer data and mass balance. The project is proposing the use of Siemens SGT6-5000F gas turbines - operational and transient emissions are based on Siemens data.[1] For natural gas-fired equipment, emissions calculations are based on the Higher Heating Value (HHV) of the natural gas fuel.

Maximum and Annual Emissions

Table 1 presents maximum annual emission totals for each power block operational scenario. Table 1A presents maximum annual facility Hazardous Air Pollutant (HAP) emissions. PEP is a major facility of NO_x, CO (attainment pollutant), VOC, and PM_{10} and is not a major source of HAPs (less than 10 tons of any single HAP and less than 25 tons per year of combination of HAPs.)

Maximum annual operational scenario emissions are based upon a series of worst-case assumptions for each pollutant. The worst-case annual emissions profiles will be dependent upon pollutant and which worst-case operating scenario assumption produces the maximum annual potential to emit.

- For the highest annual emissions of NO_x, SO_x, and $PM_{10/2.5}$ and CO2e, up to 7,960 hours of operation at base load, up to 35 warm starts, five (5) cold start, and up to 40 shutdowns per year for a total of 8,000 hours per year with up to 24 hours per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 836 hours per year. This is identified on the attached spreadsheet in Appendix A, Table A-1A as Operational Scenario 1.

- For the highest annual emissions of CO and VOC, up to 3,625 hours at base load with up to 360 hot starts, 360 warm starts, five (5) cold starts, and up to 725 shutdowns for a total of 4,320 hours per year with up to 24-hour per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 4,884 hours per year. This is identified in Appendix A, Table A-1B as Operational Scenario 2.

- The third Operational Scenario is based on 4,470hours per year of base load operation, up to 180 hot starts, 360 warm starts, 5 cold starts, and up to 545 shutdowns per year for a total of 5,000 hours per year with up to 24-hours per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 4,136 hours per year. This is identified in Appendix A, Table A-1C as Operational Scenario 3.

- All three emissions scenarios are based on a 64 degree Fahrenheit day and include 1,500 hours per year for the duct burners in the HRSG with up to 24 hours per day of operation.

- Emission totals for fire pump and emergency generator are based on maximum of 50 and 26 hours per year for maintenance and testing, respectively.

[1] "Revised Petition To Amend (Application for Certification)" Palmdale Energy LLC, July 2015

Maximum annual SO_x emissions are calculated with a fuel sulfur content of 0.2 grains/100 dry standard cubic feet and complete conversion of fuel sulfur to exhaust SO_x. Maximum total SO_x emissions are presented as 11.39 tpy, but an unknown fraction of these (fuel sulfur) emissions are accounted for in the PM_{10} emissions (as the PM_{10} estimate includes filterable and condensable particulate). For this project, $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.

Table 1 – PEP Maximum Annual Emission Totals for Power Block
(All emissions presented in tons per year)

	NO_x	**CO**	**VOC**	**SO_x**	**PM_{10}**	**$PM_{2.5}$**
Operational Scenario 1	*138.75*	102.43	30.83	*11.39*	*81.00*	*81.00*
Operational Scenario 2	122.17	*351.02*	*51.63*	6.52	48.08	48.08
Operational Scenario 3	122.11	289.60	45.39	7.41	54.09	54.09
Maximum	**138.75**	**351.02**	**51.63**	**11.39**	**81.00**	**81.00**

Table 1A – PEP Maximum Annual Facility Emissions
(All emissions presented in tons per year)

	NO_x	**CO**	**VOC**	**SO_x**	**PM_{10}**	**$PM_{2.5}$**
Power Block	138.75	351.02	51.63	11.39	81.00	81.00
Emergency Generator	0.22	0.04	0.01	0.00	0.01	0.01
Fire Pump	0.02	0.03	0.00	0.00	0.00	0.00
Facility Maximum	**138.99**	**351.09**	**51.65**	**11.39**	**81.01**	**81.01**

Table 1B – PEP Maximum Annual HAP Emissions (All emissions presented in pounds per year)		
	Total	**Threshold**
Acetaldehyde	967	20,000
Acrolein	134	20,000
Benzene	95	20,000
1,3-Butadiene	1	20,000
Ethylbenzene	127	20,000
Formaldehyde	16,169	20,000
Hexane	1827	20,000
Naphthalene	12	20,000
Total PAHs	2	20,000
Propylene	5,445	20,000
Propylene Oxide	337	20,000
Tolulene	505	20,000
Xylene	187	20,000
TOTAL HAPS	25,807	**50,000**
Ammonia	250,636	n/a
Diesel PM[a]	14	n/a

Note: Threshold equivalent to 10 tpy per HAP and 25 tpy combined.
[a]Diesel Particulate Matter is a surrogate for all air toxics emitted by the diesel engine.

Maximum Daily Emissions

Table 2 presents maximum daily facility emissions calculated under worst case conditions. Maximum daily NO_x, CO, and VOC emissions are calculated by assuming one warm start, one hot start, and two shutdowns and 22.083 hours of operation (with duct burners) at the 23 degree Fahrenheit hourly rate. Maximum daily SO_x and PM_{10} emissions are calculated by assuming 24 hours of operation at the maximum fuel use rate (with duct burners) with a fuel sulfur content of 0.75 grains/100 dscf and complete conversion of fuel sulfur to exhaust SO_x. The auxiliary boiler emissions are estimated at full load for two hours. The fire pump and emergency generator emissions are estimated based on a once week, testing duration of 1.0 and 0.5 hours, respectively.

Table 2 – PEP Maximum Daily Operational Emissions

	NO_x	CO	VOC	SO_x	$PM_{10/2.5}$
Pounds per day	1176	2270	487	271	585

Hourly Emission Rates

Table 3 presents maximum hourly emission rates for each CTG (including HRSG) in operational mode.

Table 3 – PEP Operational Mode Maximum Hourly Emission Rates (per CTG) All values in pounds per hour					
Mode	**NO_x**	**CO**	**VOC**	**SO_x**	**PM_{10} /$PM_{2.5}$**
23° F at 100% load without duct burner	17.10	10.40	3.00	5.250	9.8
23° F at 100% load with duct burner	18.50	11.30	6.36	5.63	11.80

*SO_x hourly emissions based on 0.75 gr/100 dscf.

5. Control Technology Evaluation

Best Available Control Technology (BACT) is required for all new permit units at any new facility that emits, or has the potential to emit, 25 tons per year or more of any non-attainment pollutant or its precursors (AVAQMD Rule 1303(A)(3)). The proposed project site is state non-attainment for ozone and PM_{10} and their precursors, and Federal non-attainment for ozone and its precursors. Based on the proposed project's maximum emissions as calculated in §4 above, each permit unit at the proposed project must be equipped with BACT/Lowest Achievable Emission Rate (LAER) for NO_x and VOC, and BACT for CO, PM_{10} and $PM_{2.5.}$ The project will trigger BACT for CO and $PM_{2.5}$ through PSD review; the AVAQMD specifies CO and $PM_{2.5}$ BACT here to show its findings in advance of the PSD issuance by EPA. The applicant has submitted a BACT analysis that evaluates the BACT and LAER for these pollutants. Although SO_2 emissions will not exceed 25 tpy, the Project will implement BACT for SO_2 as a PM_{10} precursor.

The definition of BACT, as defined in AVAQMD Rule 1301 (N) is similar to the definition of LAER under the Federal non-attainment NSR regulations. In the following discussion of control technology evaluation, BACT as required by AVAQMD rules is referred to as LAER to avoid confusion with the Federal requirement for the use of BACT (which is less stringent than LAER) for attainment pollutants under the PSD regulations.

This LAER/BACT Evaluation is based on the most current data readily available through on-line databases and recent combined cycle power plant permitting in the Mojave Desert Air Basin.

Both proposed internal combustion engines will be limited to emergency use, except for a limited number of hours for testing and maintenance, and required to comply with current emergency internal combustion BACT, which is conformance with CARB ATCM standards and use of CARB ultra-low sulfur diesel fuel (0.0015% (wt) or 15 ppm (wt)). The generator engine must comply with Tier 2 emission standards, and the fire suppression water pump Tier 3 emission standards.

All concentration levels presented in the following BACT determinations are corrected to 15% oxygen, unless otherwise specified. See also the discussion of Applicable Requirements in Section 10 of this analysis document. The BACT emission rates must be at least as stringent as applicable federal regulations such as the National Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP). This has been found to be the case for PEP.

Ammonia is a by-product of the selective catalytic reduction process, as some ammonia does not react and remains in the exhaust stream. As ammonia is not a regulated criteria air pollutant, but is a hazardous and toxic compound, the AVAQMD will address ammonia emissions as an element of the toxics new source review analysis (§8).

NO_x LAER/BACT

NO_x is a precursor of ozone, PM_{10} and $PM_{2.5}$. NO_x will be formed by the oxidation of atmospheric nitrogen during combustion within the gas turbine generating systems.

A review of recent combined-cycle CTG NO_x LAER determinations demonstrates that 2.0 ppm is the most stringent NO_x limit to date, with varying averaging times. PEP is requesting 2.0 ppmvd averaged over one hour.

A limit on the ammonia slip is an integral part of the NO_x limit, due to the dynamics of the reduction chemistry and physical limits to the extent of the effective reduction chemistry zone (limited by temperature and duration). Ammonia slip dynamics are further complicated by the use of a duct burner within the HRSG, an integral part of the PEP. A review of those same recent combined-cycle CTG (with duct burners) NO_x LAER determinations demonstrates that a maximum of five ppmvd ammonia slip is an element of the most stringent NO_x limit to date. PEP is requesting five ppmvd ammonia slip averaged over one hour (not including hours of turbine startup/shutdown).

By definition operation at transient conditions will disrupt operation of the selective catalytic reduction system, through temperature and flow variation. Minimizing the duration of transient conditions will also minimize the disruption of the combustion air pollution control system. PEP proposes to use fast start technology to minimize startup durations.

In order to determine LAER during startup and shutdown conditions, a review was conducted of other combined-cycle, natural gas-fired turbine applications. The PEP Project NSR application addressed LAER for startups and shutdowns, and concluded that the fast start technology represented LAER for Siemens "F-class" combustion turbines. A review of other similar permits' operating approaches, operating controls, work practices and equipment performance and design did not identify any superior emission rates. Although it is difficult to compare the emission rates expected to be achieved with the fast start approach due to the significant variability of the emission levels permitted for combined-cycle power plants startup and shutdowns during the last decade, the emission levels proposed for PEP are significantly lower and durations are shorter than other projects reviewed.

There are no other technically feasible control techniques to further reduce NO_x emissions during startup and shutdown. Mass emission rate limits, in pounds per event, proposed during startup and shutdown, and the specification of Siemens fast start technology, therefore, represent LAER for emissions of NO_x during the short-term startup and shutdown events. The following NO_x emission rate limits are found to be LAER for these periods:

Hot Startup:	44 pounds/event per turbine
Warm Startup:	47 pounds/event per turbine
Cold Startup:	52 pounds/event per turbine
Shutdown:	33 pounds/event per turbine

The AVAQMD therefore determines that a maximum NO_x concentration of 2.0 ppmvd averaged over one hour, with an ammonia slip of 5 ppmvd averaged over one hour, and using fast start operational methods, is acceptable as NO_x LAER for the PEP combined cycle gas turbine power trains, achieved with dry low NO_x combustors and selective catalytic reduction in the presence of ammonia. Different LAER emission rates are defined above which apply during startup and shutdown operating mode.

A review of recent small scale limited use natural gas combustion boiler LAER determinations demonstrates that 9 ppmvd at 3% oxygen is the most stringent NO_x limit to date. PEP is requesting 9 ppmvd at 3% oxygen for the auxiliary boiler.

The AVAQMD also determines that a maximum NO_x concentration of 9 ppmvd at 3% oxygen is acceptable as NO_x LAER for the PEP limited use auxiliary boiler, achieved with ultra-low-NO_x burners. Since transient periods (startup and shutdown) would typically only be at 10% of the input at the maximum continuous rating, the mass emission rates during the warmup cycle would not exceed the emission rate during full capacity operation. Thus, no additional emissions control technology is proposed and no different LAER emissions limits are specified for transient operations of this equipment.

CO BACT

Carbon monoxide is formed as a result of incomplete combustion of fuel within the gas turbine generating systems.

A review of recent combined-cycle CTG (with duct burners) CO BACT determinations demonstrates that 2.0 ppm is the most stringent CO limit for similar facilities, with varying averaging times. PEP is requesting 2.0 ppmvd averaged over one hour.

By definition operation at transient conditions will disrupt operation of the catalytic oxidation system, through temperature and flow variation. Minimizing the duration of transient conditions will also minimize the disruption of the combustion air pollution control system. PEP proposes to use a fast start to minimize startup durations. Similar to the NO_x BACT discussion, a review of other similar projects did not identify emission limits or durations more stringent than those proposed by the Applicant. Since there are no other technically feasible control techniques to further reduce emissions of CO during startup and shutdown periods, the mass emission rate limits, in pounds per event, proposed to limit CO emissions during startup and shutdown, therefore, represent BACT for this Project. The following CO emission rate limits during these periods are found to be BACT:

Hot Startup:	305 pounds/event per turbine
Warm Startup:	378 pounds/event per turbine
Cold Startup:	416 pounds/event per turbine
Shutdown:	76 pounds/event per turbine

The AVAQMD therefore determines that a maximum CO concentration of 2.0 ppmvd, averaged over one hour, and using fast start operation methods, is acceptable as CO BACT for the PEP combined cycle gas turbine power trains, achieved with an oxidation catalyst. Different BACT emission rates are defined above which apply during startup and shutdown operating mode.

A review of recent small scale limited use natural gas combustion boiler BACT determinations demonstrates that 50 ppmvd at 3% oxygen is the most stringent CO limit to date. PEP is requesting 50 ppmvd at 3% oxygen for the auxiliary boiler.

The AVAQMD also determines that a maximum CO concentration of 50 ppmvd at 3% oxygen is acceptable as CO BACT for the PEP limited use auxiliary boiler, achieved with ultra-low-NO_x burners. Similar to NO_x emissions, no separate CO BACT limit is defined for this equipment during transient periods.

SO_X BACT

SO_X is a precursor to PM_{10}, a state non-attainment pollutant at the proposed facility location. SO_X is exclusively formed through the oxidation of sulfur present in the fuel. The emission rate is a function of the efficiency of the source and the sulfur content of the fuel, since virtually all fuel sulfur is converted to SO_X. CARB guidance suggests that a requirement to burn natural gas with a fuel sulfur content not greater than 1 grain/100 scf is SO_X BACT. The AVAQMD determined that sole use of natural gas with a fuel sulfur content not greater than 0.2 grains per 100 scf as fuel was SO_X BACT for the Palmdale Hybrid Power Project. Pipeline quality natural gas regulated by the California Public Utilities Commission typically must meet one grain per 100 scf. The District will limit fuel sulfur content by permit condition.

The District determines that the exclusive use of natural gas fuel with not greater than 0.2 grains/100 scf on an annual average basis is acceptable as SO_X BACT for the PEP combined cycle gas turbines. SO_X BACT is not triggered for other PEP equipment.

PM_{10} and $PM_{2.5}$ BACT

Particulate will be emitted by the gas-fired systems due to fuel sulfur, inert trace contaminants, mercaptans in the fuel, dust drawn in from the ambient air and particulate of carbon, metals worn from the equipment while in operation, and hydrocarbons resulting from incomplete combustion.

Natural-Gas Fired Equipment

There have not been any add-on particulate control systems developed for gas turbines from the promulgation of the first New Source Performance Standard for Stationary Turbines (40 CFR 60 Subpart GG, commencing with §60.330) in 1979 to the present. The cost of installing such a device has been and continues to be prohibitive and performance standards for particulate control of stationary gas turbines have not been proposed or promulgated by USEPA. Inlet filters are used to protect the gas turbine, which also have the effect of reducing particulate loading into the combustion process.

The most stringent particulate control method for gas-fired equipment is the use of low ash fuels such as natural gas. Combustion control and the use of low or zero ash fuel (such as natural gas) is the predominant control method listed for turbines and boilers with PM limits. CARB guidance suggests a requirement to burn natural gas with a fuel sulfur content not greater than 1 grain S/100 dscf is PM_{10} BACT. A review of recent combined-cycle CTG (with duct burners) PM10 BACT determinations demonstrates that 0.2 to 0.75 grain S/100 dscf is the most stringent PM10 limit for similar facilities, with varying averaging times.

PEP proposes the sole use of natural gas with a sulfur content not greater than 0.2 grains/100 dscf on an annual average basis.

The AVAQMD therefore determines that the sole use of natural gas fuel with a fuel sulfur content not greater than 0.2 grain per 100 scf on an annual average basis is acceptable as PM_{10} and $PM_{2.5}$ BACT for the PEP combined cycle gas turbine power trains and auxiliary boiler.

VOC LAER/BACT

VOC is a precursor for ozone and PM_{10} and $PM_{2.5}$. VOCs are emitted from natural gas-fired turbines as a result of incomplete combustion of fuel contained in pipeline-quality natural gas.

The most stringent VOC control level for gas turbines has been achieved by those which employ catalytic oxidation for CO control. An oxidation catalyst designed to control CO would provide a side benefit of controlling VOC emissions. The MDAQMD has determined that a maximum VOC concentration of 1 ppmvd averaged over one hour was VOC LAER for the PHPP (achieved through the use of an oxidation catalyst optimized for VOC control). PEP proposes a VOC emission limit of 1 ppmvd without duct firing, 2.0 ppmvd with duct firing, achieved through the use of an oxidation catalyst.

By definition operation at transient conditions will disrupt operation of the catalytic oxidation system, through temperature and flow variation. Minimizing the duration of transient conditions will also minimize the disruption of the combustion air pollution control system. PEP proposes to use a fast start process to minimize startup durations. VOC emissions during startup and shutdown are controlled to a lesser extent than during normal operation because the oxidation catalyst is below its normal operating temperature range. Similar to the emissions of other pollutants, the Siemens fast start technology may be capable of reducing total startup VOC emissions on the order of 50 percent. There are no other technically feasible control techniques to further reduce emissions of VOC during startup and shutdown. The mass emission rate limits, in pounds per event, proposed to limit VOC emissions during startup and shutdown therefore represent LAER as follows:

Hot Startup:	28 pounds/event per turbine
Warm Startup:	28 pounds/event per turbine
Cold Startup:	31 pounds/event per turbine
Shutdown:	20 pounds/event per turbine

The AVAQMD therefore determines that a maximum VOC concentration of 1 ppmvd averaged over one hour without duct burners, 2.0 ppmvd averaged over one hour with duct burners, and using fast start operation methods, is acceptable as VOC and trace organic LAER and TBACT for the PEP combined cycle gas turbine power trains, achieved with an oxidation catalyst.

Different LAER emission rates are defined above which apply during startup and shutdown operating mode.

A review of recent small scale limited use natural gas combustion boiler BACT/LAER determinations demonstrates that combustion controls (in accordance with NO_x controls) are the most stringent VOC control requirement. PEP is requesting natural gas as sole fuel and good combustion practices (not to exceed 0.006 lb/MMBtu VOC) for the auxiliary boiler. Not subject to TBACT as maximum individual cancer risk (MICR) is less than 1, however, proposed LAER/BACT control is also toxics control.

The AVAQMD also determines that a maximum VOC emission rate of 0.006 lb/MMBtu is acceptable as VOC LAER for the PEP limited use auxiliary boiler, achieved with good combustion practices. Similar to NO_x and CO emissions, no separate VOC BACT limit is defined for this equipment during transient periods.

6. Class I Area Visibility Protection

A visibility protection analysis is required for PEP as it is a project subject to the Federal nonattainment NSR program as a major facility of Federal nonattainment pollutants NOx and VOC (ozone precursors) and is located within 60 miles of a Class I Area.

PEP evaluated visual plume blight of project emissions on two (2) Class I areas within 60 miles of the proposed facility site.

The AVAQMD reviewed the visibility analysis methods and findings. AVAQMD found the methods to be acceptable and agrees with the findings.

Findings

PEP NOx (as NO_2) as well as PM (Federal Attainment Pollutant) emissions influence on plume blight were both well below the screening criteria at the applicable areas.

Inputs and Methods

Visibility impacts were evaluated at the Cucamonga Wilderness Area and the San Gabriel Wilderness Area. Screening meteorological data were used for the analysis. Worst-case annual emissions were used for the analysis. Particulate (PM) and NO_2 plume blight impacts were evaluated using VISCREEN.

7. Air Quality Impact Analysis

PEP performed the ambient air quality standard impact analyses for CO, PM_{10}, $PM_{2.5}$, SO_2 and NO_2 emissions. The AVAQMD approves of the analysis methods used in these impact analyses and the findings of these impact analyses.

Findings

The impact analysis calculated a maximum incremental increase for each pollutant for each applicable averaging period, as shown in Table 4 below. When added to the maximum recent conservatively augmented background concentration, the PEP did not exceed the most stringent (or lowest) standard for any pollutant except PM_{10}, which is already in excess of the State standard without the project.

Pollutant	Avg. Period	Project Impact[1] (µg/m3)	Background (µg/m3)	Total Impact[2] (µg/m3)	State Standard (µg/m3)	Federal Standard (µg/m3)
Table 4 – PEP Worst Case Ambient Air Quality Impacts						
		Normal Operating Conditions				
NO_2[a]	1-hour	204.7	99	304	339	-
	1-hr 5-yr Avg of 98th%	13.49	81	94	-	188
	Annual	0.981	15.1	16.1	57	100
CO	1-hour	123.8	2,177	2,301	23,000	40,000
	8-hour	29.48[b]	1,604	1,633	10,000	10,000
PM_{10}	24-hour	7.22[c](6.34)	185	192	50	-
	24-hour H2H	6.93[c](6.07)	80	97	-	150
	Annual	0.750	28.3	29.1	20	-
$PM_{2.5}$	24-hr 5-yr Avg of 98th%	4.74[c](4.15)	18	23	-	35
	Annual	0.750	7.2	8.0	12	-
	5-yr Avg of Annual Conc's	0.723	6.1	6.8	-	12.0
SO_2	1-hour	5.67	16	21.7	655	-
	1-hr 5-yr Avg of 99th%	5.03	10	15	-	196
	3-hour H2H	4.28	16	20.3	-	1300
	24-hour	3.00	8	11	105	-
		Start-up/Shutdown				
NO_2[a]	1-hour	60.16	98	158	339	-
	1-hr 5-yr Avg of 98th%	51.40	81	132	-	188
CO	1-hour	574.5	2,176	2,751	23,000	40,000
	8-hour	88.58	1,603	1,692	10,000	10,000

*** Background includes modeled impacts for the existing Plant 42 sources at the maximum PEP impact.**

[a] NO_2 1-hour and annual impacts evaluated using the Ambient Ratio Method with 0.80 (80%) and 0.75 (75%) ratios, respectively.

[b] CO 8-hour facility impacts greater for auxiliary boiler operating continuously without any concurrent turbine operations.
[c] PM10/PM2.5 24-hour worst-case impacts are for 43% load Case 27, which would be unlikely to occur for two turbines for a full 24-hours (i.e., two turbines at less than 50% load). The worst-case for 24-hour operations at 75% and 100% loads for PM10/PM2.5 is the same as the other pollutants – Case 2 (these impacts shown in parentheses).

Inputs and Methods

Worst case emissions were used as inputs, meaning 100 percent full load in most cases, except for half load in the case of the three hour SO_2 standard and the 24 hour PM_{10} standard. Modeling of pollutants for annual averages was conducted using the 64 degree Fahrenheit emissions rate (the annual average condition). A five-year (2010 through 2014) sequential hourly meteorological data set from the Palmdale Air Force Plant 42 Complex (aka Palmdale Airport) station was used. Mixing heights were determined from Phoenix/Tucson (2010, supplemented with Edwards AFB/Yuma) and Las Vegas (2011-2014). These 2010-2014 Palmdale ASOS surface data and concurrent Las Vegas/Phoenix/Tucson radiosonde data were processed with the latest versions of AERMET (14134) and AERMINUTE (14337). Background emission concentrations were determined using 2010-2013 emissions data from AVAQMD Lancaster air monitoring site and conservatively augmented using significant emission sources located at Palmdale Air Force Plant 42 Complex.

The ozone limiting method (OLM) was used for the 1-hour NO_2 cumulative modeling analyses (both CAAQS and NAAQS). NO_2/NO_x ISR ratios were based on USEPA guidance (a default of 0.5 for the PEP project sources (for all operating cases including startup) and a default of 0.2 for background sources in the cumulative inventory). Concurrent ozone data (2010-2014) used in the Tier 3 OLM analysis was obtained from the Lancaster monitoring station. For the cumulative 1-hour NO_2 NAAQS analyses, the third highest seasonal value by hour, averaged over three years, were included in the AERMOD modeling per USEPA guidance (March 1, 2011 USEPA memorandum *"Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour N0$_2$ National Ambient Air Quality Standard"*).

The AERMOD dispersion model (version 14134) was used to estimate ambient concentrations resulting from PEP emissions. The dispersion modeling was performed according to requirements stated in the USEPA Guideline on Air Quality Models.

8. Health Risk Assessment and Toxics New Source Review

PEP performed a Health Risk Assessment (HRA) for carcinogenic, non-carcinogenic chronic, and non-carcinogenic acute toxic air contaminants. The AVAQMD approves of the HRA methods and findings.

Findings

The HRA calculated a peak 70-year cancer risk of 3.28 per million at the point of maximum impact. The calculated peak 70-year maximum individual cancer risk is less than 1.0 per million. The maximum non-cancer chronic and acute hazard indices are both less than the significance level of 1.0 (0.0154 and 0.0271 respectively). Cancer burden is less than the significance threshold of 0.5 (0.0012). As these results make the project a "low priority" project, and as the project emits less than 10 tons per year of every single HAP and 25 tons per year of any combination of HAPs, no further toxics new source review is required for this project (Rule 1320(E)(2)(b)). Please refer to Table 1A above for a summary of project HAP/TAC emissions.

Inputs and Methods

PEP will emit toxic air contaminants as products of natural gas combustion, diesel fuel combustion, equipment wear, and ammonia slip from the SCR systems. Combustion emissions were estimated using emission factors from CARB and USEPA, and the California Air Toxics Emission Factors (CATEF) database. Ammonia slip was assumed to be 5 ppm in the stack exhaust.

The AERMOD dispersion model was used to estimate ambient concentrations of toxic air pollutants. The Hot Spots Analysis and Reporting Program (HARP2, Air Dispersion Modeling and Risk Tool) risk assessment module was used to estimate potential health risks due to exposure to emissions. The AERMET/AERMOD meteorological dataset was used for the risk analysis.

9. Offset Requirements

AVAQMD Regulation XIII – *New Source Review* requires offsets for non-attainment pollutants and their precursors emitted by large, new sources. PEP has prepared and submitted a proposed offset package for the proposed project as required by Rule 1302(C)(5)(b). PEP is proposed for a location that has been designated non-attainment by USEPA for ozone (and its precursors) and designated non-attainment by CARB for PM_{10} (and its precursors). AVAQMD Rule 1303(B)(1) specifies offset threshold amounts for the State non-attainment pollutant PM_{10}. AVAQMD Rule 1303(B)(1) also specifies offset threshold amounts for precursors of non-attainment pollutants: NO_x (precursor of ozone and PM_{10}), SO_x (precursor of PM_{10}), and VOC (precursor of ozone and PM_{10}). A new facility which emits or has the potential to emit more than these offset thresholds must obtain offsets equal to the facility's entire potential to emit. As Table 5 shows, maximum PEP annual emissions exceed the offset thresholds for three of the four non-attainment pollutants and/or precursors. The table uses PEP maximum or worst-case annual emissions (including transients). The table also includes all applicable emissions, including the emissions increases from proposed new permit units, fugitive emissions (none are proposed), and non-permitted equipment (none are proposed). For this analysis the AVAQMD assumes SO_2 is equivalent to SO_x. Note that some fraction of sulfur compounds are included in both the SO_x and the PM_{10} totals, as the PM_{10} total includes front and back half particulate. Since $PM_{2.5}$ is an attainment pollutant for both the State and Federal standards, $PM_{2.5}$ offsets are not required for PEP.

Table 5 – Comparison of PEP Emissions with Offset Thresholds
All emissions in tons per year

	NO_x	**VOC**	**SO_x**	**PM_{10}**
Maximum Annual Potential to Emit	139	52	11	81
Offset Threshold	25	25	25	15

Required Offsets

AVAQMD Rule 1305 increases the amount of offsets required based on the location of the facility obtaining the offsets (on a pollutant category specific basis). As PEP is located in a

Federal ozone non-attainment area the largest applicable offset ratio applies. For offsets that are obtained from outside the Mojave Desert Air Basin (Inter-basin) the AVAQMD can only apply the offset ratio in the same manner and to the same extent as offsets derived from a source within the AVAQMD[2]. However, the air district in which the offsets are created may under their own rules apply an additional ratio in the process of determining the amount, type and quantity of the emissions reductions.[3] In addition, CEC as the lead agency may impose an additional ratio as part of mitigation of certain potential environmental impacts pursuant to provisions of the California Environmental Quality Act (CEQA). In this particular situation, PEP has proposed the use of a 1.5 offset ratio for VOCs obtained from the San Joaquin Valley Air Basin, which is the maximum distance based ratio used by the San Joaquin Valley Air Pollution Control District (SJVAPCD). The AVAQMD concurs with this distance ratio for VOCs. Table 6 indicates the appropriate ratios, adjusted for the higher offset ratio for VOCs, and calculates the offsets required for PEP.

Table 6 – Emission Offsets Required for PEP
All emissions in tons per year

	NO_x	**VOC**	**PM_{10}**
PEP Emissions	138.99	51.65	81.01
Offset Ratio	1.3	1.3	1.0
Inter-basin Offset Ratio*	**NA**	**1.5**	**NA**
Required Offsets	**180.7**	**77.5**	**81.0**

Reasonably Available Control Technology (RACT) Adjustment

AVAQMD Rule 1305(C)(4) requires that any proposed offsets must be surplus to RACT prior to use. Each air district has a similar requirement in their rule structure, ensuring that reductions used to generate ERCs are surplus as of the date of ERC issuance. The RACT adjustment requirement then becomes a comparison between RACT as of issuance and RACT as of use. As an element of the surplus analysis, the AVAQMD has compared the nature of the source of each reduction used either for ERC generation or proposed for offset, and compared the stringency of RACT in the source air district and in the AVAQMD (the proposed destination air district). In every case except one (ERC Certificate C-1686) RACT has not increased in stringency (or there has been no RACT established, as is the case for unpaved roads).

Identified Potential Emission Reduction Credits

The Project Applicant has identified in its Offset Package sufficient VOC ERCs within the San Joaquin Valley Air Pollution Control District (SJVAPCD) and NO_x ERCs within the Mojave Desert Air Quality Management District (MDAQMD). As shown in Table 7, the Applicant has indicated that sufficient ERCs can be obtained to meet the offset requirements for the PEP shown in Table 6 with its current offset strategy. The Applicant must surrender offsets (ERCs) to the AVAQMD for the equipment before the start of construction of any part of the project for which this equipment is intended to be used (Rule 1305(D)(5)(b)(ii)).

---

[2] See Health & Safety Code §40709.6(c)
[3] See Health & Safety Code §40709.6(b)

Area and Indirect Source Offsets

AVAQMD Rule 1305[4] explicitly allows for the use of Area and Indirect Source offsets (e.g. Road Paving), as approved by the Air Pollution Control Officer, on a case-by-case basis. Prior SIP approved Rule 1309[5] does not exclude the use of such emissions reductions as offsets so long as they meet the applicable requirements of prior Rule 1309. SIP Pending Rule 1305 provides additional, more stringent, requirements to ensure that such offsets remain real, permanent, quantifiable, enforceable, and surplus. Since the AVAQMD is located in a Federal ***attainment/unclassifiable*** area for PM (including both PM_{10} and $PM_{2.5}$), federal offsets for such pollutants are not required. However, since the AVAQMD is designated state nonattainment for PM_{10} and the PEP's proposed emissions are greater than the threshold in 1303(B)(1) offsets are required to comply with District rules. Therefore, the AVAQMD will apply the provisions of current AVAQMD rule 1305 to approve/disapprove these offsets.

To offset PEP PM_{10} emissions, the Project Applicant has identified potential ERCs resulting from the paving of existing unpaved roads in the Antelope Valley. A list of unpaved roads identified by Applicant as candidates for Paving ERC (PERC) is included in Appendix B.

The MDAQMD has previously allowed the use of road paving PM_{10} reductions for New Source Review actions, and the AVAQMD supports the use of road paving PM_{10} reductions to offset natural gas combustion PM_{10} emissions within a PM_{10} non-attainment area. The AVAQMD will analyze road paving ERC quantification and issuance process in a manner similar to the MDAQMD Rule 1406[6] - *Generation of Emission Reduction Credits for Paving Unpaved Public Roads*, to determine the exact amount of ERCs that can be issued to PEP in response to the paving of any given existing unpaved road segments. Adequate existing unpaved roads are present within the AVAQMD to offset the proposed PEP. The AVAQMD has established that the identified unpaved roads exist and therefore contribute PM_{10} emissions to the atmosphere within the AVAQMD, and by extension will generate a real reduction in emissions when paved. The AVAQMD unpaved road emissions inventory is currently an area source inventory which does not accurately reflect the thousands of existing individual road segments (either paved or unpaved). When PM_{10} attainment planning requirements apply to the AVAQMD (State or Federal), this deficit will be corrected. As required by Rule 1305(B)3(d)(ii), control of each identified road segment can be sufficiently demonstrated through the PERC application process.

The proposed PEP ERC sources are summarized in Table 7.

[4] This Rule is currently awaiting SIP approval.

[5] The SIP approved version is the South Coast AQMD version as amended 12/7/95 and approved by USEPA at 40 CFR 52.220(c)(240))i)(A)(1) on 12/4/1996 at 61 FR 64291.

[6] This Rule has been adopted and is currently awaiting SIP submittal.

Table 7 – ERC Sources Identified by PEP All emissions in tons per year						
Air District	**Air Basin**	**Current Owner**	**ERC Certificate**	**NO_x**	**VOC**	**PM_{10}**
MDAQMD	Mojave Desert	NRG - California South,	102	240		
MDAQMD	Mojave Desert	CalPortland Cement Co.	103	854		
SJVAPCD	San Joaquin	Vector Environmental	S-4039-1		124	
SJVAPCD	San Joaquin	Crimson Resource Management	S-3387-1		38	
SJVAPCD	San Joaquin	Calpine	S-3261-1		10	
SJVAPCD	San Joaquin	Dart Container Corporation	C-555-1		164	
SJVAPCD	San Joaquin	Martin Anderson	C-1051-1		14	
SJVAPCD	San Joaquin	Anderson Rack Systems-Hannibal Industries	N-950-1		15	
SJVAPCD	San Joaquin	Heck Cellars	S-3442		20	
SJVAPCD	San Joaquin	Creations Mfg., Inc.	C-1686*		19	
SJVAPCD	San Joaquin	Silgan Container Corp.	C-1208-1		7	
SJVAPCD	San Joaquin	Silgan Container Corp.	N-431-1		8	
SJVAPCD	San Joaquin	BlueScope BNA, Inc.	1094294-71-1		16	
SJVAPCD	San Joaquin	Malibu Boats	N-942-1		33	
AVAQMD	Mojave Desert	Road Paving	TBD			>81
Total ERCs Potentially Identified:				**1094**	**468**	**>81**

*Certificate C-1686 may need to be re-evaluated for any changes that have occurred to SJVAPCD Rule 4606 after the date of the creation of the ERCs.

Inter-District and Inter-Basin Offsetting

As summarized above, current NO_x and VOC offset proposals include the use of inter-district and/or inter-basin offsets from the MDAQMD or SJVAPCD, respectively. Inter-district trades would entail the use of offsets from other districts within the Mojave Desert Air Basin, e.g., use of NO_x ERC from the MDAQMD bank. Inter-basin trades would entail use of credits from another air district located in a different air basin, e.g., VOC ERCs from the San Joaquin Valley Air Basin. AVAQMD Rule 1305(B) explicitly allows for the use of inter-district and inter-basin offsets, as approved by the Air Pollution Control Officer in consultation with CARB and the USEPA, on a case-by-case basis. The Governing Boards of the applicable Districts would have to approve by resolution any inter-district or inter-basin transfer of ERCs pursuant to Health & Safety Code Section 40709.6(d).

The AVAQMD has previously allowed the use of inter-basin offsets for the Palmdale Hybrid Power Project and the Lockheed Martin Aeronautical Company. In each case CARB and USEPA did not object to the inter-basin trade. The proposed inter-basin trade originates in an air district (SJVAPCD) that is both upwind from, and has a higher ozone non-attainment classification than, the AVAQMD. The South Coast Air Basin and San Joaquin Valley Air Basin have been determined to be a source of overwhelming transport of air pollution into the Mojave Desert Air Basin by CARB[7]; overwhelming in the sense that local emissions are overwhelmed by South Coast and San Joaquin Valley Air Basin emissions being transported into the local area. The nature of the ozone problem at the project site (and within the entire AVAQMD federal ozone attainment area) is a function of ozone and ozone precursor emissions from the SCAQMD and SJVAPCD. The regional nature of the AVAQMD ozone problem has been explicitly and implicitly recognized by both districts, CARB, and USEPA since the mid 1990s, as ozone State Implementation Plans (SIPs) submitted and approved by all four agencies include a “but for” attainment demonstration for the AVAQMD. This attainment demonstration indicates that the AVAQMD would be in attainment “but for” ozone and ozone precursors originating within the SCAQMD and SJVAPCD, and that ozone precursor emission reductions within the SCAQMD and SJVAPCD are necessary for the AVAQMD to demonstrate attainment of the Federal standard. The reduction of ERCs within the SJVAPCD and their consumption within the AVAQMD represents a reduction in potential upwind ozone precursors, in direct support of regional ozone attainment efforts. On the basis of this intimate regional ozone relationship, and supported by regional ozone attainment demonstration modeling as presented in every recent regional ozone SIP, the AVAQMD finds that the use of inter-basin ozone precursor offsets from SJVAPCD is acceptable for the PEP.

10. Applicable Regulations and Compliance Analysis

Selected AVAQMD Rules and Regulations will apply to the proposed project:

Regulation II – Permits

Rule 212 – Standards For Approving Permits establishes baseline criteria for approving permits by the AVAQMD for certain projects. In accordance with these criteria, the proposed project accomplishes all required notices and emission limits through the PDOC and complying with stringent emission limitations set forth on permits.

[7] “Ozone Transport: 2001 Review,” April 2001, CARB identifies the South Coast Air Basin as having an overwhelming and significant impact on the Mojave Desert Air Basin (which includes the Antelope Valley) and the San Joaquin Valley as having an overwhelming impact on the MDAB.

Rule 218 – *Stack Monitoring* requires certain facilities to install and maintain stack monitoring systems. The proposed project will be required to install and maintain stack monitoring systems by permit condition.

Rule 225 – *Federal Operating Permit Requirements* requires certain facilities to obtain federal operating permits. The proposed project will be required to submit an application for a federal operating permit within twelve months of the commencement of operations.

Regulation IV – Prohibitions

Rule 401 – *Visible Emissions* limits visible emissions opacity to less than 20 percent (or Ringelmann No. 1). During start up, visible emissions may exceed 20 percent opacity. However, emissions of this opacity are not expected to last three minutes or longer. In normal operating mode, visible emissions are not expected to exceed 20 percent opacity.

Rule 402 – *Nuisance* prohibits facility emissions that cause a public nuisance. The proposed turbine power train exhaust is not expected to generate a public nuisance due to the sole use of pipeline-quality natural gas as a fuel and 5 ppm limit on ammonia slip (slip at this level does not result in plume formation[8]).

Rule 403 – *Fugitive Dust* specifies requirements for controlling fugitive dust. The proposed project does not include any significant sources of fugitive dust so the proposed project is not expected to violate Rule 403.

Rule 404 – *Particulate Matter – Concentration* specifies standards of emissions for particulate matter concentrations. The sole use of pipeline-quality natural gas and CARB ultra-low sulfur diesel as fuels will keep proposed project emission levels in compliance with Rule 404.

Rule 407 – *Liquid and Gaseous Contaminants* limits CO and SO_2 emissions from stationary sources. The provisions of this rule do not apply to stationary IC engines. BACT and sole use of natural gas will ensure compliance.

Rule 408 – *Circumvention* prohibits hidden or secondary rule violations. The proposed project is not expected to violate Rule 408.

Rule 409 – *Combustion Contaminants* limits total particulate emissions on a density basis. The provisions of this rule do not apply to stationary IC engines. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 409.

Rule 429 – *Start-Up And Shutdown Exemption Provisions For Oxides Of Nitrogen* Limits startup and shutdown times with respect to NO_x emissions. Combustion turbines subject to Rule 1134 are exempt from Rule 429.

Rule 430 – *Breakdown Provisions* requires the reporting of breakdowns and excess emissions. The proposed project will be required to comply with Rule 430 by permit condition.

---

[8] EPA fact sheet EPA-452/F-03-032

Rule 431.1 and 431.2 – *Sulfur Content in Fuels* limits sulfur content in gaseous and liquid fuels. The sole use of CARB Diesel Fuel and pipeline-quality natural gas as fuels will keep the proposed project in compliance with Rule 431.

Rule 475 – *Electric Power Generating Equipment* limits particulate matter discharged into the atmosphere from sources having rating of greater than 10 MW. The sole use of pipeline-quality natural gas as fuels will keep the proposed project in compliance with Rule 475.

Rule 476 – *Steam Generating Equipment* limits NO_x and particulate matter from steam boilers, including the auxiliary boiler, and specifies monitoring and recordkeeping for such equipment. The proposed project will have specific permit conditions requiring compliance with these provisions.

Regulation IX – Standards of Performance for New Stationary Sources

Regulation IX includes by reference the New Source Performance Standards (NSPS) for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60 Subpart Db), NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60 Subpart IIII), NSPS for New Stationary Combustion Turbines (40 CFR 60 Subpart KKKK), and NSPS for New Stationary Combustion Turbines (40 CFR 60 Subpart TTTT). Additionally, the District was granted authority as the administrator of these regulations[9]. Permit conditions for the proposed project will establish limits which are in compliance with the turbine, auxiliary boiler, and compression ignition engine NSPS referenced in Regulation IX. A brief summary of applicable requirements is presented below.

Subpart A *General Provisions*

Any source subject to an applicable standard under 40 CFR Part 60 is also subject to the general provisions of Subpart A. Because the Project is subject to Subparts KKKK, TTTT, IIII, and Db, the requirements of Subpart A will also apply. The Project operator will comply with the applicable notifications, performance testing, recordkeeping and reporting outlined in Subpart A.

Subpart Db *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 MMBtu/hr. The rule imposes limits on SO_2 emissions for oil- and coal-fired units; limits on PM emissions for units that combust coal, wood or municipal solid waste, alone or in combination with other fuels; and limits on NO_x emissions for natural gas fired units of 0.20 lb/MMBtu. Subpart Db would only apply to the auxiliary boiler because it has a heat input rate exceeding 100 MMBtu/hr. This boiler will only be fueled with natural gas, thus Subpart Db does not limit SO_2 or PM emissions from natural gas–fired units. Subpart Db limits NOx emissions based on the heat release rate. This unit has a high heat release rate of 79,000 Btu/hr-ft3 and thus the unit is subject to 0.20 lb/MMBtu from natural gas-fired units. The BACT-derived NO_x emission limit of 0.011 lb/MMBtu is substantially less than the Subpart Db limit; thus the auxiliary boiler will comply

[9] D. Jordan (USEPA Region IX) to R. Fletcher (CARB), June 7, 2011.

with the NSPS emission requirements. By permit condition the o/o will comply with emission monitoring and recordkeeping.

The o/o shall demonstrate compliance with the auxiliary boiler NOx emissions limit through source test and use of an alternative compliance demonstration method pursuant to §60.49(b)(c) for.

While the HRSG and associated duct burners will be in excess of 100 MMBtu/hr, this unit is exempt from the requirements of Db because they are regulated under Subpart KKKK.

Subpart IIII *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines that commence construction after July 11, 2005. Relevant to the proposed Project, the rule applies to the fire water pump CI engine and to the emergency electrical generator CI engine as follows:

> (i) Non fire water pump engines manufactured after April 1, 2006;
> (ii) Fire water pump engines with less than 30 liters per cylinder manufactured after 2009;
> Or
> (iii) Fire water pump engines manufactured as a certified National Fire Protection Association fire water pump engine after July 1, 2006.

For the purpose of this rule, "manufactured" means the date the owner places the order for the equipment. Based on the timeline projected for obtaining approval of the Project, the applicant expects that the engines will be ordered (and thus manufactured) in 2018.

Owners and operators of fire water pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards listed for all pollutants. For model year 2016 or later 175-horsepower (hp) engines, the limits are 2.6 grams per horsepower-hour (g/hp-hr) for CO, 3.0 g/hp-hr for non-methane hydrocarbons (NMHC) and NO_x combined, and 0.22 g/hp-hr for PM_{10}. The PEP will install a Tier 3 engine meeting these standards.

Owners and operators of non-fire pump engines must comply with the emission standards listed for all pollutants. For a model year 2016 or later engine with 750 hp or more, the limits are 2.6 g/hp-hr for CO, 4.8 g/hp-hr for NMHC and NO_x combined, and 0.15 g/hp-hr for PM_{10}. The Project will install a Tier 2 emergency generator engine meeting these standards.

Subpart KKKK *Standards of Performance for Stationary Combustion Turbines*
Subpart KKKK places emission limits of NO_x and SO_2 on new combustion turbines and the associated HRSG and duct burners. For new combustion turbines firing natural gas with a rated heat input greater than 850 MMBtu/hr, NO_x emissions are limited to 15 ppm at 15 percent O2 of useful output (0.43 pounds per megawatt-hour [lb/MWh]).

SO_x emissions are limited by either of the following compliance options:

1. The operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 ng/J (0.90 lb/MWh) gross output, or

2. The operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 0.060 lbs SO_2/MMBtu heat input. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

As described in the BACT section, the PEP will use a SCR system to reduce NO_x emissions to 2.0 ppm and pipeline natural gas to limit SO_2 emissions to 0.0006 pounds per MMBtu to meet BACT requirements, which ensures that the Project will satisfy the requirements of Subpart KKKK. Subpart KKKK limit for NOx is 15 ppmv @ 15% O2 (§60.4320); SO2 limit is 0.060 lb/MMBtu (§60.4330).

Subpart TTTT *Standards of Performance for New Stationary Combustion Turbines*
In January, 2014, the USEPA re-proposed the standards of performance regulating CO_2 emissions from new affected fossil-fuel-fired generating units, pursuant to Section 111(b) of the Clean Air Act. The final rule was published in the Federal Register on August 3, 2015, and will become effective on or about October 3, 2015. The rule applies to new sources such as PEP constructed after January 8, 2014. The rule establishes separate standards for two types of sources, i.e., stationary combustion turbines firing natural gas, and electric utility steam generating units (generally firing coal). The final CO_2 standard for combined cycle combustion turbines is 1000 lbs CO_2/MWh- gross. The PEP facility is expected to comply with this standard.

Regulation XI – Source Specific Standards

Rule 1113 – *Architectural Coatings* limits VOC content of applied architectural coatings. The proposed project will be required to use compliant coatings by permit condition.

Rule 1134 – *Emissions of Oxides of Nitrogen from Stationary Gas Turbines* limits NO_x emissions from combined-cycle turbines and specifies monitoring and recordkeeping for such equipment. The proposed project will have specific permit conditions requiring compliance with these provisions.

Rule 1135 – *Emissions of Oxides of Nitrogen from Electric Power Generating Systems*. This rule is only applicable to units existing in 1991 which are owned by specific utilities or their successors. Since PEP will be constructed after 1991 and is not owned by any entity listed in the rule, this rule is not applicable to PEP.

Rule 1146 – *Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters*. This rule does not apply to boilers used to generate electricity therefore the auxiliary boiler is not subject to this rule.

Regulation XIII – New Source Review

Rule 1300 – *General* ensures that Prevention of Significant Deterioration (PSD) requirements apply to all projects. The proposed project has submitted an application to the USEPA for a PSD permit that regulates PEP emissions of NO_2, CO and $PM_{2.5}$, complying with Rule 1300.

Rule 1302 – *Procedure* requires certification of compliance with the Federal Clean Air Act, applicable implementation plans, and all applicable AVAQMD rules and regulations. The ATC application package for the proposed project includes sufficient documentation to comply with Rule 1302(D)(5)(b)(iii). Permit conditions for the proposed project will require compliance with Rule 1302(D)(5)(b)(iv).

Rule 1303 – *Requirements* requires BACT and offsets for selected large new sources. Permit conditions will limit the emissions from the proposed project to a level which has been defined as BACT for the proposed project, bringing the proposed project into compliance with Rule 1302(A). Prior to the commencement of construction, the proposed project shall have obtained sufficient offsets to comply with Rule 1303(B)(1).

Rule 1305 – *Emissions Offsets* provides the procedures and formulas to determine the eligibility, calculations and use of Offsets required pursuant to the provisions of District Rule 1303 (B). Fugitive Emissions, as defined in Rule 1301 (HH), will be included when calculating the base quantity of offsets as required by Rule 1305.

Rule 1306 – *Electric Energy Generating Facilities* places additional administrative requirements on projects involving approval by the California Energy Commission (CEC). The proposed project will not receive an ATC without CEC's approval of their revised Application for Certification, ensuring compliance with Rule 1306.

Rule 1309 – *Emission Reduction Credits* establishes a system by which all reductions in the emission of air contaminants (which are to be used to offset certain future increases in emissions) shall be banked prior to use to offset future increases in emissions. Reductions in PM_{10} emissions from the paving of unpaved roads will be analyzed, quantified, and issued using a process similar to the MDAQMD Rule 1406 and banked in accordance with the requirements and stipulations of Rule 1309.

Regulation XIV – Toxics and Other Non-Criteria Pollutants

Rule 1401 – New Source Review For Toxic Air Contaminants – requires proposed projects be reviewed for potential health impacts before construction. Significant new or modified sources must use the Best Available Control Technology to minimize toxic air contaminant emissions. Ensures any new or modified sources control toxic emissions as required by ATCM and/or NESHAP/MACT. Permit requirements will ensure compliance with all applicable ATCM and/or NESHAP/MACT. Based on the results of PEP Health Risk Assessment, the each proposed project source was determined to be less than significant, therefore TBACT is not required.

Rule 1402 – *Control of Toxic Air Contaminants From Existing Sources* – requires any new or existing Facility control emissions of TAC or Regulated Toxic Substances and provides opportunity for the public to comment on projects deemed significant. Proposed PEP source toxic emissions are limited by virtue of permit conditions. Results of PEP HRA demonstrate that the proposed facility is not a significant and therefore toxics public notification is not required.

Regulation XII – Prevention of Significant Deterioration

This regulation is not currently implemented by the AVAQMD because the USEPA has not delegated authority for the PSD Program to the AVAQMD at this time.

Regulation XXX – Federal Operating Permits

Regulation XXX contains requirements for sources which must have a federal operating permit and an acid rain permit. The proposed project will be required to submit applications for a federal operating permit and an acid rain permit by the appropriate date. The federal operating permit application is required to be submitted within one year after the PEP commences operation. An acid rain permit application is required by 40 CFR Part 72 to be submitted at least 24 months prior to the date when the affected unit commences commercial operation.

National Emission Standards for Hazardous Air Pollutants/Maximum Achievable Control Technology Standards

Health & Safety Code §39658(b)(1) states that when USEPA adopts a standard for a toxic air contaminant pursuant to §112 of the Federal Clean Air Act (42 USC §7412), such standard becomes the Airborne Toxic Control Measure (ATCM) for the toxic air contaminant. Once an ATCM has been adopted it becomes enforceable by the AVAQMD 120 days after adoption or implementation (Health & Safety Code §39666(d)). USEPA has adopted a National Emission Standards for Hazardous Air Pollutants (NESHAP) that is applicable to the emergency engines.

The NESHAP for Stationary Reciprocating Internal Combustion Engines ("RICE NESHAP", 40 CFR Part 63 Subpart ZZZZ) limits emissions of toxic air pollutants from stationary RICE. This rule is applicable to both stationary emergency RICE proposed for this project. Each of the proposed engines is "new" as defined by the rule as they will be installed on or after June 12, 2006.

According to the RICE NESHAP, new stationary emergency RICE must meet the requirements of the New Source Performance Standards, 40 CFR part 60 subpart IIII for CI engines. These engines have no further requirements under the RICE NESHAP. Permit conditions have been included in the permit to ensure compliance with the NESHAP.

40 CFR 98 – Mandatory Greenhouse Gas Reporting – sources that in general emit 25,000 metric tons or more of carbon dioxide equivalent per year in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP) and the proposed project is required to report the annual CO_2e emissions because they have the PTE over the 25,000 metric ton threshold. Permit conditions have been added to specify compliance with the reporting requirements.

40 CFR 64 – Compliance Assurance Monitoring (CAM) – The CAM rules require facilities to monitor the operation and maintenance of emissions control systems and report malfunctions of any control system to the appropriate regulatory agency. The CAM rule applies to emissions units with uncontrolled potential to emit levels greater than applicable major source thresholds. However, emission control systems governed by Title V operating permits requiring continuous compliance determination methods are exempt from the CAM rule. Since the project will be issued a Title V permit requiring the installation and operation of continuous emissions monitoring systems (CO monitoring as a surrogate for VOC monitoring) the project will qualify for this exemption from the requirements of the CAM rule.

11. Conclusion

The AVAQMD has reviewed the proposed project's Application for New Source Review and subsequent supplementary information. Additionally, the AVAQMD addresses comments herein which were made pertaining to the initial PDOC (see history of revisions for details). The AVAQMD has determined that the proposed project, after application of the permit conditions (including BACT/LAER requirements) given below, will comply with all applicable AVAQMD Rules and Regulations.

This PDOC Revision A initiates consultation with USEPA and CARB pertaining to inter-district and inter-basin ERC's as required by District Rule 1305.

This PDOC Revision A will be publicly noticed no later than May 12, 2016, including copies to USEPA, CARB, and CEC. Written comments will be accepted for thirty days from the date of publication of the public notice. This PDOC Revision A will remain available for public inspection at the District office.

Please forward any comments on this document to:

> Bret Banks
> Air Pollution Control Officer
> Antelope Valley Air Quality Management District
> 43301 Division Street, Suite 206
> Lancaster, CA 93535-4649

12. Permit Conditions

The following permit conditions will be placed on the Authorities to Construct (ATC) for the project. Separate permits will be issued for each turbine power train. Separate permits will also be issued for each oxidation catalyst, SCR system, duct burner, auxiliary boiler, and emergency internal combustion engine. The electronic version of this document contains a set of conditions that are essentially identical for each of multiple pieces of equipment, differing only in AVAQMD permit reference numbers. The signed and printed ATCs will have printed permits (with descriptions and conditions) in place of condition language listings. For each IC engine, the ATC will also list the emission rate for that unit in the description.

Unless otherwise denoted, the origin of the following conditions is founded in District Regulation XIII.

Combustion Turbine Generator Power Block Authority to Construct Conditions

[2 individual 2,467MMBtu/hr F Class Gas Combustion Turbine Generators, Application Numbers: AV2000000504 and AV2000000505]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
   [Rule 204]

2. This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.2 grains per 100 dscf on a rolling twelve month average basis, and shall be operated and maintained in accordance with the recommendations of its manufacturer or supplier and/or sound engineering principles. Compliance with this limit shall be demonstrated by providing evidence of a contract, tariff sheet or other approved documentation that shows that the fuel meets the definition of pipeline quality gas and records of monthly fuel sulfur content.
   [Rule 1303; Rule 431.1; 40 CFR 60.4365; 40 CFR 60.5520(d)(1)]

3. This equipment is subject to the Federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions), KKKK (Standards of Performance for New Stationary Gas Turbines), and TTTT (Standards of Performance for Greenhouse Gas Emissions from New Stationary Gas Turbines). This facility is also subject to the Prevention of Significant Deterioration (40 CFR 52.21) and Federal Acid Rain (Title IV) programs. Compliance with all applicable provisions of these regulations is required.

4. Emissions from this equipment (including its associated duct burner) shall not exceed the following emission limits at any firing rate, except for CO, NO_x and VOC during periods of startup and shutdown:
   a. Hourly rates, computed every 15 minutes, verified by CEMS and annual compliance tests:
      i. NO_x as NO_2 – 2.0 ppmvd corrected to 15% O_2 and 18.50 lb/hr, based on a 1-hr average
      ii. CO – 2.0 ppmvd corrected to 15% O_2 and 11.30 lb/hr, based on a 1-hr average.
   b. Hourly rates, verified by compliance tests or other compliance methods in the case of SOx:
      i. VOC as CH_4 – 2.0 ppmvd corrected to 15% O_2 and 6.36 lb/hr
      ii. SO_x as SO_2 – 5.63 lb/hr (based on 0.75 grains/100 dscf fuel sulfur)
      iii. $PM_{10/2.5}$ – 11.80 lb/hr

   Emissions from this equipment (not including the associated duct burner) shall not exceed the following emission limits at any firing rate, except for CO, NO_x and VOC during periods of startup and shutdown:
   c. Hourly rates, computed every 15 minutes, verified by CEMS and annual compliance tests:

   i. NO_x as NO_2 – 2.0 ppmvd corrected to 15% O_2 and 17.10 lb/hr, averaged over one hour
   ii. CO – 2.0 ppmvd corrected to 15% O_2 and10.40 lb/hr, averaged over one hour

d. Hourly rates, verified by compliance tests or other compliance methods in the case of SOx:
   i. VOC as CH_4 – 1 ppmvd corrected to 15% O_2 and 3.00 lb/hr
   ii. SO_x as SO_2 – 5.25 lb/hr (based on 0.75 grains/100 dscf fuel sulfur)
   iii. $PM_{10/2.5}$ – 9.80 lb/hr

[Rule 404; Rule 407; Rule 409; Rule 475; Rule 1134; Rule 1303; NSPS Subpart KKKK]

5. Emissions of CO and NO_x from this equipment shall only exceed the limits contained in Condition 4 during startup and shutdown periods as follows. Transient conditions shall not exceed the following durations:
   a. Cold Startup- A gas turbine (GT) startup (SU) that occurs when the steam turbine (ST) rotor temperature is less than 485°F after a GT shutdown (SD), and is limited in time to the lesser of:
      i. the first 39 minutes of continuous fuel flow to the GT after ignition; or
      ii. the period of time from GT ignition until the GT achieves the first of two consecutive CEM data points in compliance with the emission concentration limits of Parts 4(a) and 4(b).
   b. Warm Startup- A GT SU that occurs when the ST rotor temperature is greater than or equal to 485°F but less than 685°F after a GT SD, and is limited in time to the lesser of:
      i. the first 35 minutes of continuous fuel flow to the GT after ignition; or
      ii. the period of time from GT ignition until the GT achieves the first of two consecutive CEM data points in compliance with the emission concentration limits of Parts 4(a) and 4(b).
   c. Hot Startup-A GT SU that occurs when the ST rotor temperature is greater than 685°F after a GT SD, and is limited in time to the lesser of:
      i. the first 30 minutes of continuous fuel flow to the GT after ignition; or
      ii. the period of time from GT ignition until the GT achieves the first of two consecutive CEM data points in compliance with the emission concentration limits of Parts 4(a) and 4(b).
   d. Shutdown-The lesser of the 25-minute period immediately prior to the termination of fuel flow to the GT or the period of time from non-compliance with any requirement listed in Parts 4(a) and 4(b) until termination of fuel flow to the GT.
   e. During a cold startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 52 lb
      ii. CO – 416 lb
   f. During a warm startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 47 lb
      ii. CO – 378 lb
   g. During a hot startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 43 lb
      ii. CO – 305 lb
   h. During a shutdown emissions shall not exceed the following, verified by CEMS:

i. NO_x – 33 lb
ii. CO – 76 lb
[Rule 1303]

6. Emissions (including startup, shutdown, and malfunction) from this facility, including the duct burner, auxiliary boiler, and engines, shall not exceed the following emission limits, based on a calendar day summary:
   a. NO_x – 1176 lb/day, verified by turbine CEMS
   b. CO – 2270 lb/day, verified by turbine CEMS
   c. VOC as CH_4 – 487 lb/day, verified by compliance tests, fuel use data and hours of operation in mode
   d. SO_x as SO_2 – 74 lb/day, verified by fuel sulfur content and fuel use data
   e. $PM_{10/2.5}$ – 585 lb/day, verified by compliance tests, fuel use data and hours of operation

   [Rule 1303]

7. Emissions (including startup, shutdown, and malfunction) from this facility, including the duct burner, auxiliary boiler, and engines, shall not exceed the following emission limits, based on a rolling 12 month summary:
   a. NO_x – 138.99 tons/year, verified by turbine CEMS
   b. CO – 351.09 tons/year, verified by turbine CEMS
   c. VOC as CH_4 – 51.65 tons/year, verified by compliance tests, fuel use data and hours of operation in mode
   d. SO_x as SO_2 – 11.39 tons/year, verified by fuel sulfur content and fuel use data
   e. PM_{10} – 81.01 tons/year, verified by compliance tests, fuel use data and hours of operation
   f. $PM_{2.5}$ – 81.01 tons/year, verified by compliance tests, fuel use data and hours of operation

   [Rule 1303]

8. Particulate emissions from this equipment shall not exceed an opacity equal to or greater than twenty percent (20%) for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor.
   [Rule 401]

9. This equipment shall exhaust through a stack at a minimum height of 160 feet.
   [Rule 1303]

10. The owner/operator (o/o) shall not operate this equipment after the initial commissioning period without the oxidation catalyst with valid District permit TBD and the selective catalytic reduction system with valid District permit TBD installed.
    [Rule 1303]

11. The o/o shall provide stack sampling ports and platforms necessary to perform source tests required to verify compliance with District rules, regulations and permit conditions. The location of these ports and platforms shall be subject to District approval.

[Rule 1303]

12. Emissions of NO_x and CO, and oxygen shall be monitored using a Continuous Emissions Monitoring System (CEMS). Ammonia slip shall be monitored using Parametric Emissions Monitoring System (PEMS). Turbine fuel consumption shall be monitored using a continuous monitoring system. Stack gas flow rate shall be monitored using either a Continuous Emission Rate Monitoring System (CERMS) meeting the requirements of 40 CFR 75 Appendix A or a stack flow rate calculation method. The o/o shall install, calibrate, maintain, and operate these monitoring systems according to a District-approved monitoring plan, AVAQMD Rule 218, 40 CFR 60 and/or 40 CFR 75[10] as applicable.
[Rule 1134; Rule 1303; NSPS KKKK]

13. The o/o shall conduct all required compliance/certification tests in accordance with a District-approved test plan. Thirty (30) days prior to the compliance/certification tests the operator shall provide a written test plan for District review and approval. Written notice of the compliance/certification test shall be provided to the District ten (10) days prior to the tests so that an observer may be present. A written report with the results of such compliance/certification tests shall be submitted to the District within forty-five (45) days after testing.
[District Compliance Test Procedural Manual; Rule 1303; Rule 1134]

14. After the initial compliance test, the o/o shall perform the following compliance tests at least as often as once every three years on this equipment in accordance with the AVAQMD Compliance Test Procedural Manual. The test report shall be submitted to the District no later than six weeks prior to the expiration date of this permit. The following compliance tests are required:
    a. NO_x as NO_2 in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Methods 19 and 20).
    b. VOC as CH_4 in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Methods 25A and 18).
    c. SO_x as SO_2 in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Method 6 or 6C or equivalent).
    d. CO in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Method 10).
    e. PM_{10} and $PM_{2.5}$ in mg/m^3 at 15% oxygen and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).
    f. Flue gas flow rate in dscf per minute (measured per USEPA Method 2B).
    g. Opacity (measured per USEPA reference Method 9).
    h. Ammonia slip in ppmvd at 15% oxygen. (measured per BAAQMD ST-1B)

    [Rule 1134; Rule 1303]

15. The o/o shall, at least as often as once every three years following planned facility outages (commencing with the initial compliance test), include the following supplemental source tests:
    a. Characterization of cold startup VOC emissions;
    b. Characterization of other startup VOC emissions; and

[10] Where 40 CFR 60 and 40 CFR 75 are applicable but inconsistent, 40 CFR 75 shall take precedent.

c. Characterization of shutdown VOC emissions.
[Rule 1303]

16. Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B (or otherwise District approved):
    a. For NO_x, 40 CFR 75.
    b. For O_2, Performance Specification 3.
    c. For CO, Performance Specification 4.
    d. For stack gas flow rate, 40 CFR 75.
    e. For ammonia, a District approved procedure that is to be submitted by the o/o.
    f. For stack gas flow rate (without CERMS), a District approved procedure that is to be submitted by the o/o.

    [Rule 218; Rule 1134]

17. The o/o shall submit to the APCO and USEPA Region IX the following information for the preceding calendar quarter by January 30, April 30, July 30 and October 30 of each year this permit is in effect. Each January 30 submittal shall include a summary of the reported information for the previous year. This information shall be maintained on site and current for a minimum of five (5) years and shall be provided to District personnel on request:
    a. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NO_x emission rate and ammonia slip.
    b. Total plant operation time (hours), duct burner operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, and hours in shutdown.
    c. Date and time of the beginning and end of each startup and shutdown period.
    d. Average plant operation schedule (hours per day, days per week, weeks per year).
    e. All continuous emissions data reduced and reported in accordance with the District-approved CEMS protocol.
    f. Maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NO_x, CO, PM_{10}, $PM_{2.5}$, VOC and SO_x (including calculation protocol).
    g. Fuel sulfur content (monthly laboratory analyses, monthly natural gas sulfur content reports from the natural gas supplier(s), or the results of a custom fuel monitoring schedule approved by USEPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart KKKK and 40 CFR Part 72 as applicable)
    h. A log of all excess emissions, including the information regarding malfunctions/breakdowns required by Rule 430.
    i. Any permanent changes made in the plant process or production which would affect air pollutant emissions, and indicate when changes were made.
    j. Any maintenance to any air pollutant control system (recorded on an as-performed basis).
    k. Records of steam turbine rotor temperature.

    [Rule 1303; NSPS KKKK; Rule 431.1; Rule 430; Rule 1134]

18. The o/o must surrender to the District sufficient valid Emission Reduction Credits for this equipment before the start of construction of any part of the project for which this

equipment is intended to be used. In accordance with Regulation XIII the operator shall obtain 180.7 tons of NO_x, 77.5 tons of VOC, and 81.0 tons of PM_{10} offsets.
[Rule 1303(B); Rule 1305; Rule 1309]

19. During an initial commissioning period of no more than 180 days, commencing with the first firing of fuel in this equipment, NO_x, CO, VOC and ammonia concentration limits shall not apply. The o/o shall minimize emission of NO_x, CO, VOC and ammonia to the maximum extent possible during the initial commissioning period.
[Rule 1303]

20. The o/o shall tune each CTG and HRSG to minimize emissions of criteria pollutants at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor.
[Rule 1303]

21. The o/o shall install, adjust and operate each SCR system to minimize emissions of NO_x from the CTG and HRSG at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor. The NO_x and ammonia concentration limits of condition #4 above and condition #4 below (SCR conditions) (TBD) respectively shall apply coincident with the steady state operation of the SCR systems.
[Rule 1303]

22. The o/o shall submit a commissioning plan to the District and the CEC at least four weeks prior to the first firing of fuel in this equipment. The commissioning plan shall describe the procedures to be followed during the commissioning of the CTGs, HRSGs and steam turbine. The commissioning plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, the purpose of the activity, and emissions monitoring . The activities described shall include, but not be limited to, the tuning of the dry low NO_x combustors, the installation and testing of the CEMS, and any activities requiring the firing of the CTGs and HRSGs without abatement by an SCR system.
[Rule 1303]

23. The total number of firing hours of each CTG and HRSG without abatement of NO_x by the SCR shall not exceed 639 hours during the initial commissioning period. Such operation without NO_x abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place and operating. Upon completion of these activities, the o/o shall provide written notice to the District and CEC and the unused balance of the unabated firing hours shall expire.
[Rule 1303]

24. During the initial commissioning period, emissions from this facility shall not exceed the following emission limits (verified by PEMS):
    a. NO_x - 30 tons, and 132 pounds/hour/CTG
    b. CO - 185 tons, and 4500 pounds/hour/CTG

[Rule 1303]

25. No later than 180 days after initial startup, the operator shall perform an initial compliance test. This test shall demonstrate that this equipment is capable of operation at 100% load in compliance with the emission limits in Condition 4.
[Rule 1303]

26. The initial compliance test shall include tests for the following:
    a. Formaldehyde;
    b. Certification of CEMS, PEMS, and CERMS (or stack gas flow calculation method) at 100% load, startup modes and shutdown mode;
    c. Characterization of cold startup VOC emissions;
    d. Characterization of other startup VOC emissions; and
    e. Characterization of shutdown VOC emissions.
[Rule 1303]

27. This equipment is subject to 40 CFR 60 Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units. Carbon dioxide emissions from this turbine shall not exceed 1,000 lb CO2/MWh (gross) or 1,030 lb CO2/MWh (net).
[40 CFR 60 Subpart TTTT §60.5520]

HRSG Duct Burner Authority to Construct Conditions

[2 individual 193.1 MMBtu/hr Natural Gas Duct Burners,
Application Numbers: AV2000000512 and AV2000000513]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
[Rule 204]

2. This equipment shall be exclusively fueled with pipeline quality natural gas and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.
[Rule 431.1; Rule 1303]

3. The duct burner shall not be operated unless the combustion turbine generator with valid District permit TBD, catalytic oxidation system with valid District permit TBD, and selective catalytic NO_x reduction system with valid District permit TBD are in operation.
[Rule 1303]

4. This equipment shall not be operated for more than 1500 hours per rolling twelve-month period.
[Rule 1303]

5. Monthly hours of operation for this equipment shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.
[Rule 1303]

Oxidation Catalyst System Authority to Construct Conditions

[2 individual oxidation catalyst systems, Application Numbers: AV2000000506 and AV2000000507]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
   [Rule 204]

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.
   [Rule 204]

3. This equipment shall be operated concurrently with the combustion turbine generator with valid District permit TBD.
   [Rule 1303]

Selective Catalytic Reduction System Authority to Construct Conditions

[2 individual SCR systems, Application Numbers: AV2000000508 and AV2000000509]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
   [Rule 204]

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.
   [Rule 204]

3. This equipment shall be operated concurrently with the combustion turbine generator with valid District permit TBD.
   [Rule 1303]

4. Ammonia shall be injected whenever the selective catalytic reduction system has reached a minimum 400 degrees Fahrenheit except for periods of equipment malfunction.
   [Rule 1303]

5. Except during periods of startup and shutdown, ammonia slip shall not exceed 5 ppmvd averaged over one hour at 15 percent O_2, dry. The operator shall calculate and continuously record the NH_3 slip concentration using the following: NH_3(ppmv) = [a-b*(c*1.2}/lE6]*1E6/b, where a= NH_3 injection rate (lb/hr)/l7(1b/lbmol), b=dry exhaust flow rate (scf/hr)/(385.5 scf/lbmol}, c=change in measured NO_x across the SCR, ppmvd at 15 percent O_2. The operator shall install a NO_x analyzer to measure the SCR inlet NO_x ppm accurate to within +/- 5 percent calibrated at least once every 12 months.

The o/o shall use the method described above or another alternative method approved by the APCO.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information determination without corroborative date using an approved reference method for the determination of ammonia.
[Rule 1303]

6. The owner/operator shall record and maintain for this equipment the following on site for a minimum of five (5) years and shall be provided to District personnel upon request.
   a. Ammonia injection, in pounds per hour
   b. Temperature, in degrees Fahrenheit at the inlet to the SCR.

   [Rule 1303]

Auxiliary Boiler Authority to Construct Conditions

[One 110 MMBtu/hr Gas Fired Auxiliary Boiler, Application Number: AV2000000503]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
   [Rule 204]

2. This equipment shall be exclusively fueled with pipeline quality natural gas and shall be operated and maintained in accordance with the recommendations of its manufacturer or supplier and/or sound engineering principles.
   [Rule 431.1; Rule 1303(A); 40 CFR 60 Subpart Db]

3. This equipment is subject to the Federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and Db (Industrial-Commercial-Institutional Steam Generating Units).

4. Emissions from this equipment shall not exceed the following emission limits at any firing rate, verified by fuel use and annual compliance tests:
   a. NO_x as NO_2 – 9.0 ppmvd corrected to 3% O_2, 0.011 lbs/MMBtu, and 1.21 lb/hr (averaged over one hour)
   b. CO – 50 ppmvd corrected to 3% O_2, 0.037 lbs/MMBtu, and 4.07 lb/hr (averaged over one hour)
   c. VOC as CH_4 – 0.006 lbs/MMBtu and 0.66 lb/hr
   d. SO_x as SO_2 – 0.0022 lbs/MMBtu and 0.25 lb/hr (based on 0.75 grains/100 dscf fuel sulfur)
   e. $PM_{10/2.5}$ – 0.007 lbs/MMBtu and 0.77 lb/hr (front and back half)

   [Rule 404; Rule 407; Rule 409; Rule 475; Rule 476; Rule 1303(A); 40 CFR 60.44b]

5. This equipment shall not be operated for more than 4,884 hours per rolling twelve month period.
   [Rule 1303]

6. The o/o shall maintain an operations log for this equipment on-site and current for a minimum of five (5) years, and said log shall be provided to District personnel on request. The operations log shall include the following information at a minimum:
   a. Total operation time (hours per month, by month);
   b. Daily fuel use (to be used for calculating annual (12 month rolling sum) capacity factor;
   c. Maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NO_x, CO, $PM_{10/2.5}$, VOC and SO_x (including calculation protocol); and,
   c. Any permanent changes made to the equipment that would affect air pollutant emissions, and indicate when changes were made.

   [Fuel Sulfur Monitoring- 40 CFR 60.42(b)(k)(2); 40 CFR 60.49b(r)(1)]

7. The o/o shall perform the following annual compliance tests on this equipment in accordance with the AVAQMD Compliance Test Procedural Manual. The test report shall be submitted to the District no later than six weeks prior to the expiration date of this permit. The following compliance tests are required:
   a. NO_x as NO_2 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 19 and 20).
   b. VOC as CH_4 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 25A and 18).
   c. SO_x as SO_2 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Method 6 or 6C or equivalent).
   d. CO in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Method 10).
   e. PM_{10} and $PM_{2.5}$ in mg/m^3 at 3% oxygen and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).
   f. Flue gas flow rate in dscf per minute (measured per USEPA Method 2B or F Factor).
   g. Opacity (measured per USEPA reference Method 9) initial test only

   [40 CFR 60.44b(l) and 60.46b(c)(e)(g); Rule 1303]

8. A non-resettable four-digit (9,999) hour timer shall be installed and maintained on this unit to indicate elapsed operating time.
   [Rule 1303]

9. This equipment shall exhaust through a stack at a minimum height of 60.5 feet.
   [Rule 1303]

10. The o/o shall continuously monitor and record fuel flow rate and flue gas oxygen level.
    [40 CFR 60 Subpart Db, Section 60.49b; Reporting and Recordkeeping Requirements]

11. In lieu of installing CEMs to monitor NOx emissions, and pursuant to 40 CFR 60 Subpart Db, Section 60.49b(c), the owner/operator shall monitor boiler operating conditions and estimate NOx emission rates per a District approved emissions estimation plan. The plan shall be based on the annual source tests required by Condition 7. The plan shall include test results, operating parameters, analysis, conclusions and proposed NOx estimating relationship consistent with established emission chemistry and operational effects. Any proposed changes to a District-approved plan shall include subsequent test results,

operating parameters, analysis, and any other pertinent information to support the proposed changes. The District must approve any emissions estimation plan or revision for estimated NOx emissions to be considered valid. [40 CFR 60 Subpart Db, Section 60.49b(c)]

Emergency Generator Authority to Construct Conditions

[One 2011 hp emergency IC engine driving a generator, Application Number: AV2000000502]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
[Rule 204]

2. This stationary certified EPA Tier 2 diesel IC engine shall be installed, operated and maintained in accordance with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of contaminants.
[Rule 1303; NSPS IIII]

3. This unit shall be limited to use for emergency power, defined as in 17 CCR 93115. In addition, this unit may be operated as part of a testing program that does not exceed 0.5 hours in any one day and not more than 26 hours of testing or maintenance per year (rolling 12 month sum). Furthermore, pursuant to District Rule 1110.2, this unit shall be operated less than 200 hours per calendar year. This requirement includes usage during emergencies.
[District Rule 1302; 17 CCR 93115; NSPS IIII]

4. This engine shall not be operated for testing purposes during CTG startup/shutdown periods or tested during the same hour as the fire pump.
[Rule 1303]

5. This unit shall only be fired on ultra-low sulfur diesel fuel, whose sulfur concentration is less than or equal to 15 ppm on a weight basis per CARB Diesel Fuel or equivalent requirements.
[Rule 404; Rule 431.2; 17 CCR 93115; NSPS IIII]

6. A non-resettable four digit hour timer shall be installed and maintained on this unit to indicate elapsed engine operating time.
[17 CCR 93115; NSPS IIII; Rule 1302]

7. The owner/operator shall maintain a log for this unit, which, at a minimum, contains the information specified below. This log shall be maintained current and on-site for a minimum of five (5) years and shall be provided to District personnel on request:
   a. Date and time of each use or test;
   b. Duration of each use or test in hours;
   c. Reason for each use;
   d. Cumulative calendar year use, in hours; and,

e. Fuel sulfur concentration (the o/o may use the supplier's certification of sulfur content if it is maintained as part of this log).
[17 CCR 93115; NSPS IIII; Rule 1302]

8. This unit shall not be used to provide power to the interconnecting utility and shall be isolated from the interconnecting utility when operating.
[Rule 1303]

9. Engine may operate in response to notification of impending rotating outage if the area utility has ordered rotating outages in the area where the engine is located or expects to order such outages at a particular time, the engine is located in the area subject to the rotating outage, the engine is operated no more than 30 minutes prior to the forecasted outage, and the engine is shut down immediately after the utility advises that the outage is no longer imminent or in effect.
[17 CCR 93115]

10. This engine shall exhaust through a stack at a minimum height of 20 feet.
[Rule 1303]

11. This equipment shall comply with the applicable requirements of the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines- Title 17 CCR 93115 and the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines- 40 CFR Part 60 Subpart IIII.

Emergency Fire Suppression Water Pump Authority to Construct Conditions

[One 140 hp emergency IC engine driving a fire suppression water pump, Application Number: AV2000000501]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
[Rule 204]

2. This stationary certified EPA Tier 3 diesel IC engine shall be installed, operated and maintained in accordance with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of contaminants.
[Rule 1303]

3. This direct-drive fire pump engine shall be limited to use for emergency fire suppression, defined as in 17 CCR 93115. In addition, this unit may be operated as part of a testing program that does not exceed 1 hour in any one day and not more than 50 hours of testing or maintenance per year (rolling 12 month sum). Furthermore, pursuant to District Rule 1110.2, this unit shall be operated less than 200 hours per calendar year. This requirement includes usage during emergencies.
[Rule 1302; 17 CCR 93115; NSPS IIII]

4. This engine shall not be operated for testing purposes during CTG startup/shutdown periods or tested during the same hour as the emergency generator.
[Rule 1303]

5. This unit shall only be fired on ultra-low sulfur diesel fuel, whose sulfur concentration is less than or equal to 15 ppm on a weight basis per CARB Diesel or equivalent requirements.
[Rule 404; Rule 431.2; 17 CCR 93115; NSPS IIII]

6. A non-resettable four digit hour timer shall be installed and maintained on this unit to indicate elapsed engine operating time.
[17 CCR 93115; NSPS IIII; Rule 1302]

7. The owner/operator shall maintain a log for this unit, which, at a minimum, contains the information specified below. This log shall be maintained current and on-site for a minimum of five (5) years and shall be provided to District personnel on request:
a. Date and time of each use or test;
b. Duration of each use or test in hours;
c. Reason for each use;
d. Cumulative calendar year use, in hours; and,
e. Fuel sulfur concentration (the o/o may use the supplier's certification of sulfur content if it is maintained as part of this log).
[17 CCR 93115; NSPS IIII; Rule 1302]

8. This engine shall exhaust through a stack at a minimum height of 19.5 feet.
[Rule 1303]

9. This equipment shall comply with the applicable requirements of the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines- Title 17 CCR 93115 and the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines- 40 CFR Part 60 Subpart IIII.

(this page intentionally left blank)

Appendix A - PEP Emissions Calculation

Table A-1A

Maximum Hourly, Daily, and Annual Emissions Calculations

Case #: Ops Scenario 1 - Cold Day and ISO Cases

Number of Identical Engines: 2

Turbine Model: SCC6-5000F

Input data per unit:	Max Operation hrs/day	Max Annual Op hrs	Avg # of Cold Startups day	Avg # of Warm Startups day	Avg # of Hot Startups day	Cold Startup Time hrs	Warm Startup Time hrs	Hot Startup Time hrs	Shutdown Time hrs	Cold Starts events/yr	Warm Starts events/yr	Hot Starts events/yr	Estimated Shutdowns yr	Max Estimated Shutdowns day
	24	8000	0	0	0	0.65	0.583	0.5	0.417	5	35	0	40	0

	Cold Startup Emissions lbs/event	Warm Startup Emissions lbs/event	Hot Startup Emissions lbs/event	Shutdown Emissions lbs/event	Steady State Emissions w/o DB lbs/hr	Emissions w/DB lbs/hr	Worst Hr Emissions w/DB lbs/hr	Total Cold Start hrs/yr	Total Warm Start hrs/yr	Total Hot Start hrs/yr	Total Shutdown hrs/yr	Annual Steady State Non SU/SD hrs/yr	Total Annual Emissions Cold Starts lbs/yr	Warm Starts lbs/yr	Hot Starts lbs/yr	Shutdowns lbs/yr
					Case11	***Case 12***	***Case 2***									
NOx	51.48	46.80	43.20	33.00	16.70	18.10	18.50	3.25	20.405	0	16.68	7959.665	257.4	1638.0	0.00	1320.0
CO	415.80	378.00	304.80	75.90	10.20	11.00	11.30			Total SU-SD Hours/Yr:		40.335	2079.0	13230.0	0.00	3036.0
VOC	30.36	27.60	27.60	19.80	3.00	6.18	6.36				Steady State Hour Breakdown		151.8	966.0	0.00	792.0
SOx	3.41	3.06	2.63	2.35	5.25	5.63	5.63					Hrs/yr	17.1	107.1	0.00	94.0
PM10	7.56	7.56	6.48	4.07	9.70	11.70	11.80		Duct burner firing, max hours/yr:			1500	37.8	264.6	0.00	162.8
PM2.5	7.56	7.56	6.48	4.07	9.70	11.70	11.80		Non-duct burner firing, hours/yr:			6459.665	37.8	264.6	0.00	162.8
NH3	10.32	8.59	6.45	7.17	15.40	16.80	17.20						51.6	300.7	0.00	286.8
Notes:					ISO+ Day	ISO+ Day	Cold Day									

					Annual Fuel Use Values	mmbtu/hr	hrs/yr		mmbtu/yr
Cold start plus shutdown =		1.067	hrs						
Warm start plus shutdown =		1	hrs		Case11 w/o DB *	2221.42	6500		14439230
Hot start plus shutdown =		0.917	hrs		Case 12 w/DB	2409.55	1500		3614325
Shut down =		0.417	hrs		*includes SU/SD hours			Total =	18053555

Maximum Estimated Annual Emissions		NOx lbs/yr	CO lbs/yr	VOC lbs/yr	SOx lbs/yr	PM10 lbs/yr	PM2.5 lbs/yr	NH3 lbs/yr
Ops Scenario								
Cold Startups		257.4	2079.0	151.8	17.1	37.8	37.8	51.6
Warm Startups		1638.0	13230.0	966.0	107.1	264.6	264.6	300.7
Hot Startups		0.0	0.0	0.0	0.0	0.0	0.0	0.00
Shutdowns		1320.0	3036.0	792.0	94.0	162.8	162.8	286.8
Steady State w/o DB		107876.4	65888.6	19379.0	33913.2	62658.8	62658.8	99478.8
Steady State w/DB		27150.0	16500.0	9270.0	8437.5	17550.0	17550.0	25200.0
	1 Turbine Total, lbs/yr:	*138241.8*	*100733.6*	*30558.8*	*42568.9*	*80674.0*	*80674.0*	*125317.9*
	1 Turbine Total, tons/yr:	69.12	50.37	15.28	21.28	40.34	40.34	62.66
		NOx tpy	CO tpy	VOC tpy	SOx tpy	PM10 tpy	PM2.5 tpy	NH3 tpy
	Total Tons/Yr All Units:	**138.24**	**100.73**	**30.56**	**42.57**	**80.67**	**80.67**	**125.32**
EPA	PSD Program Trigger Levels, TPY:	100	100	100	100	100	100	
EPA	PSD Significant Emissions Rates, TPY:	40	100	40	40	15	10	
AVAQMD	Air Agency Offset Trigger Levels, TPY:	25	100	25	25	15	15	

Maximum Estimated Daily Emissions based on a 24 Ops Cold Day		
Max Daily Emissions Assumptions (Per turbine):		**Hours**
cold starts per day =	1	0.65
warm starts per day =	0	0
hot starts per day =	0	0
shutdowns per day =	1	0.417
Steady state ops hrs/day =		22.933

	lbs/day	lbs/day all units
NOx	508.74	1017.48
CO	750.84	1501.69
VOC	196.01	392.03
SOx	135.00	270.00
PM10	283.20	566.40
PM2.5	283.20	566.40
NH3	411.94	823.88

Maximum Estimated Hourly Emissions	
Max hourly emissions assumptions (Per turbine):	Hours
1. Cold startup	0.65
2. remainder of hour, cold day no DB, Case 1	0.35
3. NH3 is cold day data-steady state	

	lbs/hr	lbs/hr All Units	Case 1 for used for remaining hour of start (lb/hr)
NOx	57.47	114.93	17.1
CO	419.44	838.88	10.4
VOC	31.41	62.82	3
SOx	5.63	11.25	1.4
PM10	11.80	23.60	9.8
PM2.5	11.80	23.60	9.8
NH3	15.85	31.70	15.8

GHG Emissions Estimates										
Fuel:	Natural Gas				short			CO2e		
Btu/scf:	1024	HHV	*Emissions*	lbs/yr	tons/yr		IPCC SAR	short		
Heat Rate:	18053555	mmbtu/yr		2.11E+09	1.06E+06		Values	tons/yr		
Fuel Rate:	17630.4248	mmscf/yr		3.98E+04	1.99E+01		1	1.06E+06		
Emissions Factors				3.98E+03	1.99E+00		21	4.18E+02		
CO2	116.89	lbs/mmbtu					310	6.17E+02		
CH4	0.002205	lbs/mmbtu					Total CO2e:	1,056,175	short TPY	1 Engine
N2O	0.0002205	lbs/mmbtu					Total CO2e:	2,112,350	short TPY	All Engines
							Total CO2e:	960,159	metric TPY	1 Engine
Emissions Factors for GHG, 40 CFR 98, Subpart C, Tables C-1, C-2.							**Total CO2e:**	**1,920,318**	**metric TPY**	All Engines

1 short ton = 2000 lbs, 1 metric ton = 2200 lbs.

Notes:
1. Turbine emissions based on the following:
   - NOx 2.0 ppm
   - CO 2.0 ppm
   - VOC 1.0 - 2.0 ppm
2. Startup data has 20% and 10% margin added to the startup and shutdown emissions, respectively.
3. Cold start event data is based on 100% turbine load at end of start cycle
4. Short-term emissions based on 23 degree day
5. Annual emissions based on 64 degree day with 1500 hours of DB
6. GT+DB VOC at 2.2 ppm reduced to BACT level of 2.0 ppm

Data References:
1. Siemens, Summit Palmdale, 2x1 Estimated Stack Emissions Sheet, April 16, 2015
2. Siemens, Startup/Shutdown Emissions Sheet
3. Siemens, Summit Palmdale, 2x1 ACC, Performance Estimate Data Sheet, april 17, 2015
4. Siemens, Summit Palmdale, Total Plant Startup Curve, 2x1, SGT6-5000F with SST6-5000 ST, Rev 001, April 17, 2015
5. AVAQMD, FDOC, 5-13-2010, Table 1.

Aux Boiler

Calculation of Criteria Pollutant Emissions for Boilers Firing Gaseous Fuels

Boiler Operation Mode:		Normal Ops				# of Units:	1		
	Ops Hr/Day:	24				Fuel Type:	Nat Gas		
	Ops Hr/Yr:	836							

Calculation of Criteria Pollutant Emissions from Each Identical Unit						All Units			
Compound	Emission Factor, lbs/mmbtu	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
NOx	0.0110	1.21	29.04	1011.56	0.51	1.21	29.04	1011.6	0.51
CO	0.0370	4.07	97.68	3402.52	1.70	4.07	97.68	3402.5	1.70
VOC	0.0060	0.66	15.84	551.76	0.28	0.66	15.84	551.8	0.28
SOx	0.0022	0.25	5.91	55.18	0.03	0.25	5.91	55.2	0.03
PM10	0.0070	0.77	18.48	643.72	0.32	0.77	18.48	643.7	0.32
PM2.5	0.0070	0.77	18.48	643.72	0.32	0.77	18.48	643.7	0.32
	lbs/MMbtu								
CO2	116.88800	12857.68	308584.32	10749020.48	5374.51	12857.68	308584.32	10749020.5	5374.51
Methane	0.00220	0.24	5.82	202.74	0.10	0.24	5.82	202.7	0.10
N2O	0.00022	0.02	0.58	20.27	0.01	0.02	0.58	20.3	0.01
CO2e								*short tons*	5380.1
SOx Annual	0.0006	0.066						*metric tons*	4891.0

Notes:
(1) natural gas criteria pollutant EF factors
(2) Based on maximum hourly boiler fuel use of 110 MMBtu/hr/boiler
and fuel HHV of 1024 Btu/scf gives 0.1074 MMscf/hr/boiler.
(3) Based on maximum annual boiler fuel use of 91,960 MMBtu/yr/boiler
and fuel HHV of 1024 Btu/scf gives 89.8047 MMscf/yr/boiler.
(4) PM2.5 = PM10

Refs:
(1) EFs from PHPP 08-AFC-9, Appendix G
(2) GHG Factors and HHV value from 40 CFR 98.38, Tables C-1, C-2
(3) LNBs/FGR and GCPs
(4) SCR not proposed
(5) SO2 based on nat gas at 0.20 grs S/100scf

Maximum Emissions Totals for Ops Scenario (Turbines, DBs, Aux Boiler)

	NOx	CO	VOC	SOx	PM10	PM2.5	NH3	CO2e
lbs/hr	116.14	842.95	63.48	11.50	24.37	24.37	31.70	-
lbs/day	1019.90	1509.83	393.35	270.49	567.94	567.94	823.88	-
TPY	138.75	102.43	30.83	42.60	81.00	81.00	125.32	2117730

Table A-1B																
Maximum Hourly, Daily, and Annual Emissions Calculations											Number of Identical Engines:	2				
Case #:	Ops Scenario 2 - Cold Day and ISO Cases										Turbine Model:	SCC6-5000F				
Input data per unit:			Avg	Avg	Avg	Cold	Warm	Hot						Max		
	Max	Max	# of Cold	# of Warm	# of Hot	Startup	Startup	Startup	Shutdown	Cold	Warm	Hot	Estimated	Estimated		
	Operation	Annual	Startups	Startups	Startups	Time	Time	Time	Time	Starts	Starts	Starts	Shutdowns	Shutdowns		
	hrs/day	Op hrs	day	day	day	hrs	hrs	hrs	hrs	events/yr	events/yr	events/yr	yr	day		
	24	4320	0	1	1	0.65	0.583	0.5	0.417	5	360	360	725	2		
	Cold	Warm	Hot		Steady State		Worst Hr					Annual				
	Startup	Startup	Startup	Shutdown	Emissions	Emissions	Emissions	Total Cold	Total Warm	Total Hot	Total	Steady State		Total Annual Emissions		
	Emissions	Emissions	Emissions	Emissions	w/o DB	w/DB	w/DB	Start	Start	Start	Shutdown	Non SU/SD	Cold Starts	Warm Starts	Hot Starts	Shutdowns
	lbs/event	lbs/event	lbs/event	lbs/event	lbs/hr	lbs/hr	lbs/hr	hrs/yr	hrs/yr	hrs/yr	hrs/yr	hrs/yr	lbs/yr	lbs/yr	lbs/yr	lbs/yr
					Case11	***Case 12***	***Case 2***									
NOx	51.48	46.80	43.20	33.00	16.70	18.10	18.50	3.25	209.88	180	302.325	3624.545	257.4	16848.0	15552.00	23925.0
CO	415.80	378.00	304.80	75.90	10.20	11.00	11.30				Total SU-SD Hours/Yr:	695.455	2079.0	136080.0	109728.00	55027.5
VOC	30.36	27.60	27.60	19.80	3.00	6.18	6.36				Steady State Hour Breakdown		151.8	9936.0	9936.00	14355.0
SOx	3.41	3.06	2.63	2.35	5.25	5.63	5.63					Hrs/yr	17.1	1101.6	946.80	1703.8
PM10	7.56	7.56	6.48	4.07	9.70	11.70	11.80		Duct burner firing, max hours/yr:			1500	37.8	2721.6	2332.80	2950.8
PM2.5	7.56	7.56	6.48	4.07	9.70	11.70	11.80		Non-duct burner firing, hours/yr:			2124.545	37.8	2721.6	2332.80	2950.8
NH3	10.32	8.59	6.45	7.17	15.40	16.80	17.20						51.6	3092.4	2322.00	5198.3
Notes:					ISO+ Day	ISO+ Day	Cold Day									
Cold start plus shutdown =			1.067	hrs					**Annual Fuel Use Values**		mmbtu/hr	hrs/yr		mmbtu/yr		
Warm start plus shutdown =			1	hrs					Case11 w/o DB *		2221.42	2820		6264404.4		
Hot start plus shutdown =			0.917	hrs					Case 12 w/DB		2409.55	1500		3614325		
Shut down =			0.417	hrs					*includes SU/SD hours				Total =	9878729.4		
Maximum Estimated Annual Emissions				NOx	CO	VOC	SOx	PM10	PM2.5	NH3						
				lbs/yr	lbs/yr	lbs/yr	lbs/yr	lbs/yr	lbs/yr	lbs/yr						
	Ops Scenario															
Cold Startups				257.4	2079.0	151.8	17.1	37.8	37.8	51.6						
Warm Startups				16848.0	136080.0	9936.0	1101.6	2721.6	2721.6	3092.4						
Hot Startups				15552.0	109728.0	9936.0	946.8	2332.8	2332.8	2322.00						
Shutdowns				23925.0	55027.5	14355.0	1703.8	2950.8	2950.8	5198.3						
Steady State w/o DB				35479.9	21670.4	6373.6	11153.9	20608.1	20608.1	32718.0						
Steady State w/DB				27150.0	16500.0	9270.0	8437.5	17550.0	17550.0	25200.0						
		1 Turbine Total, lbs/yr:		*119212.3*	*341084.9*	*50022.4*	*23360.6*	*46201.0*	*46201.0*	*68582.2*						
		1 Turbine Total, tons/yr:		59.61	170.54	25.01	11.68	23.10	23.10	34.29						
				NOx	CO	VOC	SOx	PM10	PM2.5	NH3						
				tpy	tpy	tpy	tpy	tpy	tpy	tpy						
	Total Tons/Yr All Units:			**119.21**	**341.08**	**50.02**	**23.36**	**46.20**	**46.20**	**68.58**						
EPA	PSD Program Trigger Levels, TPY:			100	100	100	100	100	100							
EPA	PSD Significant Emissions Rates, TPY:			40	100	40	40	15	10							
AVAQMD	Air Agency Offset Trigger Levels, TPY:			25	100	25	25	15	15							

Maximum Estimated Daily Emissions based on a 24 Ops Cold Day

Max Daily Emissions Assumptions (Per turbine):				**Hours**
cold starts per day =	0			0
warm starts per day =	1			0.583
hot starts per day =	1			0.5
shutdowns per day =	2			0.834
Steady state ops hrs/day =				22.083

	lbs/day	lbs/day all units
NOx	564.54	1129.07
CO	1084.14	2168.28
VOC	235.25	470.50
SOx	135.00	270.00
PM10	283.20	566.40
PM2.5	283.20	566.40
NH3	409.21	818.42

Maximum Estimated Hourly Emissions

Max hourly emissions assumptions (Per turbine):	Hours
1. Cold startup	0.65
2. remainder of hour, cold day no DB, Case 1	0.35
3. NH3 is cold day data-steady state	

	lbs/hr	lbs/hr All Units	Case 1 for used for remaining hour of start (lb/hr)
NOx	57.47	114.93	17.1
CO	419.44	838.88	10.4
VOC	31.41	62.82	3
SOx	5.63	11.25	1.4
PM10	11.80	23.60	9.8
PM2.5	11.80	23.60	9.8
NH3	15.85	31.70	15.8

GHG Emissions Estimates

Fuel:	Natural Gas				short			CO2e		
Btu/scf:	1024	HHV	*Emissions*	lbs/yr	tons/yr		IPCC SAR	short		
Heat Rate:	9878729.4	mmbtu/yr		1.15E+09	5.77E+05		Values	tons/yr		
Fuel Rate:	9647.1967	mmscf/yr		2.18E+04	1.09E+01		1	5.77E+05		
Emissions Factors				2.18E+03	1.09E+00		21	2.29E+02		
CO2	116.89	lbs/mmbtu					310	3.38E+02		
CH4	0.002205	lbs/mmbtu					Total CO2e:	577,929	short TPY	1 Engine
N2O	0.0002205	lbs/mmbtu					Total CO2e:	1,155,857	short TPY	All Engines
							Total CO2e:	525,390	metric TPY	1 Engine
Emissions Factors for GHG, 40 CFR 98, Subpart C, Tables C-1, C-2.							**Total CO2e:**	**1,050,779**	**metric TPY**	All Engines

1 short ton = 2000 lbs, 1 metric ton = 2200 lbs.

Notes:
1. Turbine emissions based on the following:
   - NOx 2.0 ppm
   - CO 2.0 ppm
   - VOC 1.0 - 2.0 ppm
2. Startup data has 20% and 10% margin added to the startup and shutdown emissions, respectively.
3. Cold start event data is based on 100% turbine load at end of start cycle
4. Short-term emissions based on 23 degree day
5. Annual emissions based on 64 degree day with 1500 hours of DB
6. GT+DB VOC at 2.2 ppm reduced to BACT level of 2.0 ppm

Data References:
1. Siemens, Summit Palmdale, 2x1 Estimated Stack Emissions Sheet, April 16, 2015
2. Siemens, Startup/Shutdown Emissions Sheet
3. Siemens, Summit Palmdale, 2x1 ACC, Performance Estimate Data Sheet, april 17, 2015
4. Siemens, Summit Palmdale, Total Plant Startup Curve, 2x1, SGT6-5000F with SST6-5000 ST, Rev 001, April 17, 2015
5. AVAQMD, FDOC, 5-13-2010, Table 1.

Aux Boiler

Calculation of Criteria Pollutant Emissions for Boilers Firing Gaseous Fuels

Boiler Operation Mode:	Normal Ops		# of Units:	1
Ops Hr/Day:	24		Fuel Type:	Nat Gas
Ops Hr/Yr:	4884			

	Calculation of Criteria Pollutant Emissions from Each Identical Unit					All Units			
Compound	Emission Factor, lbs/mmbtu	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
NOx	0.0110	1.21	29.04	5909.64	2.95	1.21	29.04	5909.6	2.95
CO	0.0370	4.07	97.68	19877.88	9.94	4.07	97.68	19877.9	9.94
VOC	0.0060	0.66	15.84	3223.44	1.61	0.66	15.84	3223.4	1.61
SOx	0.0022	0.25	5.91	322.34	0.16	0.25	5.91	322.3	0.16
PM10	0.0070	0.77	18.48	3760.68	1.88	0.77	18.48	3760.7	1.88
PM2.5	0.0070	0.77	18.48	3760.68	1.88	0.77	18.48	3760.7	1.88
	lbs/MMbtu								
CO2	116.88800	12857.68	308584.32	62796909.12	31398.45	12857.68	308584.32	62796909.1	31398.45
Methane	0.00220	0.24	5.82	1184.40	0.59	0.24	5.82	1184.4	0.59
N2O	0.00022	0.02	0.58	118.44	0.06	0.02	0.58	118.4	0.06
CO2e								*short tons*	31430.9
SOx Annual	0.0006	0.066						*metric tons*	28573.8

Notes:
(1) natural gas criteria pollutant EF factors
(2) Based on maximum hourly boiler fuel use of 110 MMBtu/hr/boiler
and fuel HHV of 1024 Btu/scf gives 0.1074 MMscf/hr/boiler.
(3) Based on maximum annual boiler fuel use of 537,240 MMBtu/yr/boiler
and fuel HHV of 1024 Btu/scf gives 524.6484 MMscf/yr/boiler.
(4) PM2.5 = PM10

Refs:
(1) EFs from PHPP 08-AFC-9, Appendix G
(2) GHG Factors and HHV value from 40 CFR 98.38, Tables C-1, C-2
(3) LNBs/FGR and GCPs
(4) SCR not proposed
(5) SO2 based on nat gas at 0.20 grs S/100scf

Maximum Emissions Totals for Ops Scenario (Turbines, DBs, Aux Boiler)

	NOx	CO	VOC	SOx	PM10	PM2.5	NH3	CO2e
lbs/hr	116.14	842.95	63.48	11.50	24.37	24.37	31.70	-
lbs/day	1131.49	2176.42	471.82	270.49	567.94	567.94	818.42	-
TPY	122.17	351.02	51.63	23.52	48.08	48.08	68.58	1187288

Table A-1C

Maximum Hourly, Daily, and Annual Emissions Calculations

Case #:	Ops Scenario 3 - Cold Day and ISO Cases	Number of Identical Engines:	2
		Turbine Model:	SCC6-5000F

Input data per unit:

Max Operation hrs/day	Max Annual Op hrs	Avg # of Cold Startups day	Avg # of Warm Startups day	Avg # of Hot Startups day	Cold Startup Time hrs	Warm Startup Time hrs	Hot Startup Time hrs	Shutdown Time hrs	Cold Starts events/yr	Warm Starts events/yr	Hot Starts events/yr	Estimated Shutdowns yr	Max Estimated Shutdowns day
24	5000	0	1	1	0.65	0.583	0.5	0.417	5	360	180	545	2

	Cold Startup Emissions lbs/event	Warm Startup Emissions lbs/event	Hot Startup Emissions lbs/event	Shutdown Emissions lbs/event	Steady State Emissions w/o DB lbs/hr *Case11*	Steady State Emissions w/DB lbs/hr *Case 12*	Worst Hr Emissions w/DB lbs/hr *Case 2*	Total Cold Start hrs/yr	Total Warm Start hrs/yr	Total Hot Start hrs/yr	Total Shutdown hrs/yr	Annual Steady State Non SU/SD hrs/yr	Total Annual Emissions Cold Starts lbs/yr	Warm Starts lbs/yr	Hot Starts lbs/yr	Shutdowns lbs/yr
NOx	51.48	46.80	43.20	33.00	16.70	18.10	18.50	3.25	209.88	90	227.265	4469.605	257.4	16848.0	7776.00	17985.0
CO	415.80	378.00	304.80	75.90	10.20	11.00	11.30				Total SU-SD Hours/Yr:	530.395	2079.0	136080.0	54864.00	41365.5
VOC	30.36	27.60	27.60	19.80	3.00	6.18	6.36					Steady State Hour Breakdown	151.8	9936.0	4968.00	10791.0
SOx	3.41	3.06	2.63	2.35	5.25	5.63	5.63					Hrs/yr	17.1	1101.6	473.40	1280.8
PM10	7.56	7.56	6.48	4.07	9.70	11.70	11.80		Duct burner firing, max hours/yr:			1500	37.8	2721.6	1166.40	2218.2
PM2.5	7.56	7.56	6.48	4.07	9.70	11.70	11.80		Non-duct burner firing, hours/yr:			2969.605	37.8	2721.6	1166.40	2218.2
NH3	10.32	8.59	6.45	7.17	15.40	16.80	17.20						51.6	3092.4	1161.00	3907.7
Notes:					ISO+ Day	ISO+ Day	Cold Day									
Cold start plus shutdown =		1.067	hrs						**Annual Fuel Use Values**		mmbtu/hr	hrs/yr		mmbtu/yr		
Warm start plus shutdown =		1	hrs						Case11 w/o DB *		2221.42	3500		7774970		
Hot start plus shutdown =		0.917	hrs						Case 12 w/DB		2409.55	1500		3614325		
Shut down =		0.417	hrs						*includes SU/SD hours				Total =	11389295		

Maximum Estimated Annual Emissions	NOx lbs/yr	CO lbs/yr	VOC lbs/yr	SOx lbs/yr	PM10 lbs/yr	PM2.5 lbs/yr	NH3 lbs/yr
Ops Scenario							
Cold Startups	257.4	2079.0	151.8	17.1	37.8	37.8	51.6
Warm Startups	16848.0	136080.0	9936.0	1101.6	2721.6	2721.6	3092.4
Hot Startups	7776.0	54864.0	4968.0	473.4	1166.4	1166.4	1161.00
Shutdowns	17985.0	41365.5	10791.0	1280.8	2218.2	2218.2	3907.7
Steady State w/o DB	49592.4	30290.0	8908.8	15590.4	28805.2	28805.2	45731.9
Steady State w/DB	27150.0	16500.0	9270.0	8437.5	17550.0	17550.0	25200.0
1 Turbine Total, lbs/yr:	*119608.8*	*281178.5*	*44025.6*	*26900.7*	*52499.1*	*52499.1*	*79144.6*
1 Turbine Total, tons/yr:	59.80	140.59	22.01	13.45	26.25	26.25	39.57

		NOx tpy	CO tpy	VOC tpy	SOx tpy	PM10 tpy	PM2.5 tpy	NH3 tpy
	Total Tons/Yr All Units:	**119.61**	**281.18**	**44.03**	**26.90**	**52.50**	**52.50**	**79.14**
EPA	PSD Program Trigger Levels, TPY:	100	100	100	100	100	100	
EPA	PSD Significant Emissions Rates, TPY:	40	100	40	40	15	10	
AVAQMD	Air Agency Offset Trigger Levels, TPY:	25	100	25	25	15	15	

Maximum Estimated Daily Emissions based on a 24 Ops Cold Day

Max Daily Emissions Assumptions (Per turbine):		**Hours**
cold starts per day =	0	0
warm starts per day =	1	0.583
hot starts per day =	1	0.5
shutdowns per day =	2	0.834
Steady state ops hrs/day =		22.083

	lbs/day	lbs/day all units
NOx	564.54	1129.07
CO	1084.14	2168.28
VOC	235.25	470.50
SOx	135.00	270.00
PM10	283.20	566.40
PM2.5	283.20	566.40
NH3	409.21	818.42

Maximum Estimated Hourly Emissions

Max hourly emissions assumptions (Per turbine):	Hours
1. Cold startup	0.65
2. remainder of hour, cold day no DB, Case 1	0.35
3. NH3 is cold day data-steady state	

	lbs/hr	lbs/hr All Units	Case 1 for used for remaining hour of start (lb/hr)
NOx	57.47	114.93	17.1
CO	419.44	838.88	10.4
VOC	31.41	62.82	3
SOx	5.63	11.25	1.4
PM10	11.80	23.60	9.8
PM2.5	11.80	23.60	9.8
NH3	15.85	31.70	15.8

GHG Emissions Estimates

Fuel:	Natural Gas				short		CO2e		
Btu/scf:	1024	HHV	*Emissions*	lbs/yr	tons/yr	IPCC SAR	short		
Heat Rate:	11389295	mmbtu/yr		1.33E+09	6.66E+05	Values	tons/yr		
Fuel Rate:	11122.3584	mmscf/yr		2.51E+04	1.26E+01	1	6.66E+05		
Emissions Factors				2.51E+03	1.26E+00	21	2.64E+02		
CO2	116.89	lbs/mmbtu				310	3.89E+02		
CH4	0.002205	lbs/mmbtu				Total CO2e:	666,300	short TPY	1 Engine
N2O	0.0002205	lbs/mmbtu				Total CO2e:	1,332,601	short TPY	All Engines
						Total CO2e:	605,728	metric TPY	1 Engine
Emissions Factors for GHG, 40 CFR 98, Subpart C, Tables C-1, C-2.						**Total CO2e:**	**1,211,455**	**metric TPY**	All Engines

1 short ton = 2000 lbs, 1 metric ton = 2200 lbs.

Notes:
1. Turbine emissions based on the following:
   - NOx 2.0 ppm
   - CO 2.0 ppm
   - VOC 1.0 - 2.0 ppm
2. Startup data has 20% and 10% margin added to the startup and shutdown emissions, respectively.
3. Cold start event data is based on 100% turbine load at end of start cycle
4. Short-term emissions based on 23 degree day
5. Annual emissions based on 64 degree day with 1500 hours of DB
6. GT+DB VOC at 2.2 ppm reduced to BACT level of 2.0 ppm

Data References:
1. Siemens, Summit Palmdale, 2x1 Estimated Stack Emissions Sheet, April 16, 2015
2. Siemens, Startup/Shutdown Emissions Sheet
3. Siemens, Summit Palmdale, 2x1 ACC, Performance Estimate Data Sheet, april 17, 2015
4. Siemens, Summit Palmdale, Total Plant Startup Curve, 2x1, SGT6-5000F with SST6-5000 ST, Rev 001, April 17, 2015
5. AVAQMD, FDOC, 5-13-2010, Table 1.

Aux Boiler

Calculation of Criteria Pollutant Emissions for Boilers Firing Gaseous Fuels

Boiler Operation Mode:	Normal Ops	# of Units:	1
Ops Hr/Day:	24	Fuel Type:	Nat Gas
Ops Hr/Yr:	4136		

	Calculation of Criteria Pollutant Emissions from Each Identical Unit					All Units			
Compound	Emission Factor, lbs/mmbtu	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
NOx	0.0110	1.21	29.04	5004.56	2.50	1.21	29.04	5004.6	2.50
CO	0.0370	4.07	97.68	16833.52	8.42	4.07	97.68	16833.5	8.42
VOC	0.0060	0.66	15.84	2729.76	1.36	0.66	15.84	2729.8	1.36
SOx	0.0022	0.25	5.91	272.98	0.14	0.25	5.91	273.0	0.14
PM10	0.0070	0.77	18.48	3184.72	1.59	0.77	18.48	3184.7	1.59
PM2.5	0.0070	0.77	18.48	3184.72	1.59	0.77	18.48	3184.7	1.59
	lbs/MMbtu								
CO2	116.88800	12857.68	308584.32	53179364.48	26589.68	12857.68	308584.32	53179364.5	26589.68
Methane	0.00220	0.24	5.82	1003.00	0.50	0.24	5.82	1003.0	0.50
N2O	0.00022	0.02	0.58	100.30	0.05	0.02	0.58	100.3	0.05
CO2e								*short tons*	26617.2
SOx Annual	0.0006	0.066						*metric tons*	24197.7

Notes: (1) natural gas criteria pollutant EF factors

(2) Based on maximum hourly boiler fuel use of 110 MMBtu/hr/boiler
and fuel HHV of 1024 Btu/scf gives 0.1074 MMscf/hr/boiler.

(3) Based on maximum annual boiler fuel use of 454,960 MMBtu/yr/boiler
and fuel HHV of 1024 Btu/scf gives 444.2969 MMscf/yr/boiler.

(4) PM2.5 = PM10

Refs: (1) EFs from PHPP 08-AFC-9, Appendix G

(2) GHG Factors and HHV value from 40 CFR 98.38, Tables C-1, C-2

(3) LNBs/FGR and GCPs

(4) SCR not proposed

(5) SO2 based on nat gas at 0.20 grs S/100scf

Maximum Emissions Totals for Ops Scenario (Turbines, DBs, Aux Boiler)

	NOx	CO	VOC	SOx	PM10	PM2.5	NH3	CO2e
lbs/hr	116.14	842.95	63.48	11.50	24.37	24.37	31.70	-
lbs/day	1131.49	2176.42	471.82	270.49	567.94	567.94	818.42	-
TPY	122.11	289.60	45.39	27.04	54.09	54.09	79.14	1359218

Table 4.1A-5 Emergency Gen Set Emissions Estimates

EXPECTED INTERNAL COMBUSTION ENGINE EMISSIONS

Liquid Fuel

\# of Identical Engines: 1

Emergency Generator

Mfg:	Caterpillar 3512C or Similar Engine	
Engine #:	2015 Family FCPXL78.1NZS	
kWe:	1500	
BHP:	2011	
RPM:	1800	
Fuel:	#2 Diesel	
Fuel Use:	104.6	gal/hr
Fuel HHV:	139000	Btu/gal
mmbtu/hr:	14.54	HHV
Fuel Wt:	6.87	lbs/gal
Fuel S:	0.0015	% wt.
Fuel S:	0.10305	lbs/1000 gal
SO2:	0.2061	lbs/1000 gal
SO2:	9.779	equiv.g/hr

Stack Data

Height:	20	Ft.(1)	6.096	meters
Diameter:	0.6667	Ft.	0.2032	meters
Temp:	759	deg F	677.04	Kelvins
ACFM:	10908.7		158.76	m/s
input the mfg ACFM or calculate per Exhaust sheet)				
Area:	0.349	Sq.Ft.		
Velocity:	521	Ft/Sec		

Max Daily Op Hrs/Emission Calcs Only: 1

Max Annual Op Hrs: 26

		--- for 60 mins/hour ---		Single Engine				*All Engines*			
Emissions	**EF(g/hp-hr)**	**g/hr**	**g/s**	**Lb/Hr**	**Lb/Day**	**Lbs/Yr**	**Tons/Yr**	***Lb/Hr***	***Lb/Day***	***Lbs/Yr***	***Tons/Yr***
NOx	3.78	7601.58	2.112	16.758	16.758	435.7	0.218	*16.758*	*16.758*	*435.7*	*0.218*
CO	0.67	1347.37	0.374	2.970	2.970	77.2	0.039	*2.970*	*2.970*	*77.2*	*0.039*
HC	0.19	382.09	0.106	0.842	0.842	21.9	0.011	*0.842*	*0.842*	*21.9*	*0.011*
PM (2)	0.09	180.99	0.050	0.399	0.399	10.4	0.005	*0.399*	*0.399*	*10.4*	*0.005*
SOx (3)	NA	9.779	0.003	0.022	0.0216	0.56	0.0003	*0.0216*	*0.0216*	*0.56*	*0.0003*

Notes:

(1) Stack height set equal to 3.5' above structure height

(2) PM10/PM2.5 equals PM, used in HRA for DPM emissions

(3) Based on ultralow (15 ppm) sulfur fuel

(4) Based on 1.3409 bhp per kWe

	Modeled Emission Rates	**g/s**	
	1-hr NOx	1.056	
0.5 hr/test	Ann NOx	6.267E-3	*and 1-hr NO2 NAAQS*
1 test/day	1-hr CO	0.187	
	8-hr CO	0.023	
	1-hr SO2	1.358E-3	
	3-hr SO2	4.527E-4	
	24-hr SO2	5.659E-5	
	24-hr PM	1.047E-3	
	Ann PM	1.492E-4	

Table 4.1A-6 Fire Pump Emissions Estimates

EXPECTED INTERNAL COMBUSTION ENGINE EMISSIONS

Liquid Fuel						# of Identical Engines:		1			
Emergency Fire Pump											
Mfg:	Clarke or Similar Engine					Stack Data					
Engine #:	#N/A					Height:	19.5	Ft.(1)	5.944	meters	
kWe:	#N/A					Diameter:	0.4167	Ft.	0.1270	meters	
BHP:	140					Temp:	1023	deg F	823.71	Kelvins	
RPM:	1760					ACFM:	755		28.13	m/s	
Fuel:	#2 Diesel					input the mfg ACFM or calculate per Exhaust sheet)					
Fuel Use:	9.2	gal/hr				Area:	0.1364	Sq.Ft.			
Fuel HHV:	139000	Btu/gal				Velocity:	92.28	Ft/Sec			
mmbtu/hr:	1.28	HHV				Max Daily Op Hrs:		1			
						Max Annual Op Hrs:		50			
Fuel Wt:	6.87	lbs/gal									
Fuel S:	0.0015	% wt.									
Fuel S:	0.10305	lbs/1000 gal									
SO2:	0.2061	lbs/1000 gal									
SO2:	0.860	equiv.g/hr									
		--- for 60 mins/hour ---				**Single Engine**			***All Engines***		
Emissions	**g/hp-hr**	**EF(g/hr)**	**g/s**	**Lb/Hr**	**Lb/Day**	**Lbs/Yr**	**Tons/Yr**	***Lb/Hr***	***Lb/Day***	***Lbs/Yr***	***Tons/Yr***
NOx	2.80	392	0.109	0.864	0.864	43.2	0.022	*0.864*	*0.864*	*43.2*	*0.022*
CO	3.70	518	0.144	1.142	1.142	57.1	0.029	*1.142*	*1.142*	*57.1*	*0.029*
HC	0.20	28	7.778E-3	6.173E-2	6.173E-2	3.1	0.002	*0.062*	*0.062*	*3.1*	*0.002*
PM (2)	0.22	30.8	8.556E-3	6.790E-2	6.790E-2	3.4	0.002	*0.068*	*0.068*	*3.4*	*0.002*
SOx (3)	NA	0.860	2.389E-4	1.896E-3	1.896E-3	0.09	4.740E-5	*0.0019*	*0.0019*	*0.09*	*0.0000*
		140	client EF based on 0.25%s								
Notes:							**Modeled Emission Rates**		**g/s**		
(1) Stack height set equal to 3.5' above structure height								1-hr NOx	0.109		
(2) PM10/PM2.5 equals PM, used in HRA for DPM emissions							1 hr/test	Ann NOx	6.215E-4	*and 1-hr NO2 NAAQS*	
(3) SOx EF 140 g/hr equal to sulfur content of			15	ppm			1 test/day	1-hr CO	0.144		
			~0.01	%s				8-hr CO	0.018		
								1-hr SO2	2.389E-4		
								3-hr SO2	7.964E-5		
								24-hr SO2	9.954E-6		
								24-hr PM	3.565E-4		
								Ann PM	4.883E-5		

Table 4.1A-2
Calculation of Hazardous and Toxic Pollutant Emissions

# of Units:	2
Fuel HHV:	1024 btu/scf

Calculation of Noncriteria Pollutant Emissions from Gas Turbines

	(each turbine)					All Turbines			
Compound	Emission Factor, lb/MMscf	CO Catalyst Control Multiplier	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Annual Emissions, lb/yr	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Annual Emissions, lb/yr	Annual Emissions, tons/yr
Acetaldehyde	1.37E-01	2.00E-01	6.60E-02	1.58E+00	4.83E+02	1.32E-01	3.17E+00	9.66E+02	4.83E-01
Acrolein	1.89E-02	2.00E-01	9.11E-03	2.19E-01	6.66E+01	1.82E-02	4.37E-01	1.33E+02	6.66E-02
Ammonia	(3)		1.72E+01	4.13E+02	1.38E+05	3.44E+01	8.26E+02	2.75E+05	1.38E+02
Benzene	1.33E-02	2.00E-01	6.41E-03	1.54E-01	4.69E+01	1.28E-02	3.08E-01	9.38E+01	4.69E-02
1,3-Butadiene	1.27E-04	2.00E-01	6.12E-05	1.47E-03	4.48E-01	1.22E-04	2.94E-03	8.96E-01	4.48E-04
Ethylbenzene	1.79E-02	2.00E-01	8.63E-03	2.07E-01	6.31E+01	1.73E-02	4.14E-01	1.26E+02	6.31E-02
Formaldehyde	9.17E-01	5.00E-01	1.10E+00	2.65E+01	8.08E+03	2.21E+00	5.30E+01	1.62E+04	8.08E+00
Hexane	2.59E-01	2.00E-01	1.25E-01	3.00E+00	9.13E+02	2.50E-01	5.99E+00	1.83E+03	9.13E-01
Naphthalene	1.66E-03	2.00E-01	8.00E-04	1.92E-02	5.85E+00	1.60E-03	3.84E-02	1.17E+01	5.85E-03
Total PAHs	2.41E-04	2.00E-01	1.16E-04	2.79E-03	8.50E-01	2.32E-04	5.57E-03	1.70E+00	8.50E-04
Propylene	7.71E-01	2.00E-01	3.72E-01	8.92E+00	2.72E+03	7.43E-01	1.78E+01	5.44E+03	2.72E+00
Propylene oxide	4.78E-02	2.00E-01	2.30E-02	5.53E-01	1.69E+02	4.61E-02	1.11E+00	3.37E+02	1.69E-01
Toluene	7.10E-02	2.00E-01	3.42E-02	8.21E-01	2.50E+02	6.84E-02	1.64E+00	5.01E+02	2.50E-01
Xylene	2.61E-02	2.00E-01	1.26E-02	3.02E-01	9.20E+01	2.52E-02	6.04E-01	1.84E+02	9.20E-02
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	5.00E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Notes:
(1) Provided by CATEF database.
(2) Based on maximum hourly turbine fuel use of: 2.4093E+00 mmscf/hr
Case 2, cold day, with duct firing
Based on a maximum daily turbine fuel use of: 5.7823E+01 mmscf/day
Case 2, cold day, with duct firing
Based on maximum annual turbine fuel use of: 1.7630E+04 mmscf/yr
Cases 11 and 12, ISO day, with and without duct firing
Fuel use values from Fuel Calculation Sheet
(3) Values from ammonia slip calculations by Siemens, Case 12, ISO Day
(4) Fuel use values include HRSG duct burner(s) Yes or No: Yes

CO Catalyst Control Efficiencies

	Control Frac.	Multiplier
Organic HAPs	0.80	0.20
Inorganic HAPs	0.50	0.50

Each Turbine	24	Max hrs/day
Each Turbine	8000	Max Hrs/yr

Table 4.1A-4A Aux Boiler									
Calculation of Hazardous Air Pollutant Emissions for Boilers Firing Gaseous Fuels									
Boiler Operation Mode:		Scenario 1				# of Units:	1		
Max Hourly Fuel Use:		0.1074	mmscf			Fuel Type:	Nat Gas		
Hrs/Yr:		836							
Max Annual Fuel Use:		89.7864	mmscf/yr						
Calculation of Hazardous Air Pollutant Emissions from Each Identical Unit						All Units			
HAP	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
Acetaldehyde	9.00E-04	9.67E-05	n/a	8.08E-02	4.04E-05	9.67E-05	n/a	8.08E-02	4.04E-05
Acrolein	8.00E-04	8.59E-05	n/a	7.18E-02	3.59E-05	8.59E-05	n/a	7.18E-02	3.59E-05
Ammonia		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Benzene	1.70E-03	1.83E-04	n/a	1.53E-01	7.63E-05	1.83E-04	n/a	1.53E-01	7.63E-05
1,3-Butadiene	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Ethylbenzene	2.00E-03	2.15E-04	n/a	1.80E-01	8.98E-05	2.15E-04	n/a	1.80E-01	8.98E-05
Formaldehyde	3.60E-03	3.87E-04	n/a	3.23E-01	1.62E-04	3.87E-04	n/a	3.23E-01	1.62E-04
Hexane	1.30E-03	1.40E-04	n/a	1.17E-01	5.84E-05	1.40E-04	n/a	1.17E-01	5.84E-05
Naphthalene	3.00E-04	3.22E-05	n/a	2.69E-02	1.35E-05	3.22E-05	n/a	2.69E-02	1.35E-05
PAHs (4)	1.00E-04	1.07E-05	n/a	8.98E-03	4.49E-06	1.07E-05	n/a	8.98E-03	4.49E-06
Propylene	1.55E-02	1.66E-03	n/a	1.39E+00	6.96E-04	1.66E-03	n/a	1.39E+00	6.96E-04
Propylene oxide	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Toluene	7.80E-03	8.38E-04	n/a	7.00E-01	3.50E-04	8.38E-04	n/a	7.00E-01	3.50E-04
Xylene	5.80E-03	6.23E-04	n/a	5.21E-01	2.60E-04	6.23E-04	n/a	5.21E-01	2.60E-04
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Notes:	(1) natural gas HAPs emission factors: Hidden Hills AFC, Table 5.1B-14R, April 2012.								
	(2) Fuel HHV	1024	btu/scf						
	(3) Polycyclic aromatic hydrocarbons, excluding naphthalene (treated separately).								
	(4) LNB with FGR and GCPs								
	(5) all fuel values based on full load equivalents per PEP Aux boiler data sheets								

Table 4.1A-4B Aux Boiler

Calculation of Hazardous Air Pollutant Emissions for Boilers Firing Gaseous Fuels

Boiler Operation Mode:	Scenario 2		# of Units:	1
Max Hourly Fuel Use:	0.1074	mmscf	Fuel Type:	Nat Gas
Hrs/Yr:	4884			
Max Annual Fuel Use:	524.5416	mmscf/yr		

Calculation of Hazardous Air Pollutant Emissions from Each Identical Unit						All Units			
HAP	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
Acetaldehyde	9.00E-04	9.67E-05	n/a	4.72E-01	2.36E-04	9.67E-05	n/a	4.72E-01	2.36E-04
Acrolein	8.00E-04	8.59E-05	n/a	4.20E-01	2.10E-04	8.59E-05	n/a	4.20E-01	2.10E-04
Ammonia		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Benzene	1.70E-03	1.83E-04	n/a	8.92E-01	4.46E-04	1.83E-04	n/a	8.92E-01	4.46E-04
1,3-Butadiene	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Ethylbenzene	2.00E-03	2.15E-04	n/a	1.05E+00	5.25E-04	2.15E-04	n/a	1.05E+00	5.25E-04
Formaldehyde	3.60E-03	3.87E-04	n/a	1.89E+00	9.44E-04	3.87E-04	n/a	1.89E+00	9.44E-04
Hexane	1.30E-03	1.40E-04	n/a	6.82E-01	3.41E-04	1.40E-04	n/a	6.82E-01	3.41E-04
Naphthalene	3.00E-04	3.22E-05	n/a	1.57E-01	7.87E-05	3.22E-05	n/a	1.57E-01	7.87E-05
PAHs (4)	1.00E-04	1.07E-05	n/a	5.25E-02	2.62E-05	1.07E-05	n/a	5.25E-02	2.62E-05
Propylene	1.55E-02	1.66E-03	n/a	8.13E+00	4.07E-03	1.66E-03	n/a	8.13E+00	4.07E-03
Propylene oxide	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Toluene	7.80E-03	8.38E-04	n/a	4.09E+00	2.05E-03	8.38E-04	n/a	4.09E+00	2.05E-03
Xylene	5.80E-03	6.23E-04	n/a	3.04E+00	1.52E-03	6.23E-04	n/a	3.04E+00	1.52E-03
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00

Notes:
(1) natural gas HAPs emission factors: Hidden Hills AFC, Table 5.1B-14R, April 2012.
(2) Fuel HHV 1024 btu/scf
(3) Polycyclic aromatic hydrocarbons, excluding naphthalene (treated separately).
(4) LNB with FGR and GCPs
(5) all fuel values based on full load equivalents per PEP Aux boiler data sheets

Table 4.1A-4C Aux Boiler									
Calculation of Hazardous Air Pollutant Emissions for Boilers Firing Gaseous Fuels									
Boiler Operation Mode:		Scenario 3				# of Units:	1		
Max Hourly Fuel Use:		0.1074	mmscf			Fuel Type:	Nat Gas		
Hrs/Yr:		4136							
Max Annual Fuel Use:		444.2064	mmscf/yr						
Calculation of Hazardous Air Pollutant Emissions from Each Identical Unit						All Units			
HAP	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
Acetaldehyde	9.00E-04	9.67E-05	n/a	4.00E-01	2.00E-04	9.67E-05	n/a	4.00E-01	2.00E-04
Acrolein	8.00E-04	8.59E-05	n/a	3.55E-01	1.78E-04	8.59E-05	n/a	3.55E-01	1.78E-04
Ammonia		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Benzene	1.70E-03	1.83E-04	n/a	7.55E-01	3.78E-04	1.83E-04	n/a	7.55E-01	3.78E-04
1,3-Butadiene	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Ethylbenzene	2.00E-03	2.15E-04	n/a	8.88E-01	4.44E-04	2.15E-04	n/a	8.88E-01	4.44E-04
Formaldehyde	3.60E-03	3.87E-04	n/a	1.60E+00	8.00E-04	3.87E-04	n/a	1.60E+00	8.00E-04
Hexane	1.30E-03	1.40E-04	n/a	5.77E-01	2.89E-04	1.40E-04	n/a	5.77E-01	2.89E-04
Naphthalene	3.00E-04	3.22E-05	n/a	1.33E-01	6.66E-05	3.22E-05	n/a	1.33E-01	6.66E-05
PAHs (4)	1.00E-04	1.07E-05	n/a	4.44E-02	2.22E-05	1.07E-05	n/a	4.44E-02	2.22E-05
Propylene	1.55E-02	1.66E-03	n/a	6.89E+00	3.44E-03	1.66E-03	n/a	6.89E+00	3.44E-03
Propylene oxide	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Toluene	7.80E-03	8.38E-04	n/a	3.46E+00	1.73E-03	8.38E-04	n/a	3.46E+00	1.73E-03
Xylene	5.80E-03	6.23E-04	n/a	2.58E+00	1.29E-03	6.23E-04	n/a	2.58E+00	1.29E-03
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
		0.00E+00	n/a	0.00E+00	0.00E+00	0.00E+00	n/a	0.00E+00	0.00E+00
Notes:	(1) natural gas HAPs emission factors: Hidden Hills AFC, Table 5.1B-14R, April 2012.								
	(2) Fuel HHV	1024	btu/scf						
	(3) Polycyclic aromatic hydrocarbons, excluding naphthalene (treated separately).								
	(4) LNB with FGR and GCPs								
	(5) all fuel values based on full load equivalents per PEP Aux boiler data sheets								

PEP Gas Turbine Startup Emissions

Per Unit

Mode	Time (min)	Pounds per Event					Pounds per Event with margin				
		NOx	CO	VOC	PM	Fuel Use	NOx	CO	VOC	PM	Fuel Use
"Cold" Startup (GT Ignition to Emissions Compliance @ 70% GT Load)	35	34	312	22	5.1	37,601	40.8	374.4	26.4	6.12	37,601
"Cold" Startup (GT Ignition to Emissions Compliance @ 100% GT Load)	39	42.9	346.5	25.3	6.93	51,139	51.48	415.80	30.36	8.316	51,139
"Warm" Startup (GT Ignition to Emissions Compliance @ 100% GT Load)	35	39	315	23	6.3	46,490	46.8	378	27.6	7.56	46,490
"Hot" Startup (GT Ignition to Emissions Compliance @ 100% GT Load)	30	36	254	23	5.4	38,303	43.2	304.8	27.6	6.48	38,303
Shutdown (50% GT Load to Fuel Cut Off)	11	26	67	17	1.5	7,339	28.6	73.7	18.7	1.65	7,339
Shutdown (100% GT Load to Fuel Cut Off)	25	30	69	18	3.7	26,543	33	75.9	19.8	4.07	26,543

Assumes 20% margin on startup

Assumes 10% margin on shutdown

Commissioning Emissions Commissioning Phase	First Fire and Synch Checks	GT Emissions and Combustion Tuning	SCR Commissioning	CC Tuning & Testing	Total	
SCR Installed	No	No	50%	Yes		
CO Catalyst Installed	No	No	Yes	Yes		
Hours per Unit	11	73	130	425	1,278	
# Units Operating Simultaneously *	1	1	1	2		
Avg Load %	0	50	75	100		
NOx lb/hr	122	132	54	29		
CO lb/hr	4500	796	194	123		
VOC lb/hr	516	90	22	16		
MMBtu/hr - HHV	696	1373	1945	2379		
NOx lb/mmscf	179	98	28	12		
CO lb/mmscf	6621	594	102	53		
VOC lb/mmscf	759	67	12	7		tons for both units
Total NOx lbs (2 units)	2,684	19,272	14,040	24,650	60,646	30
Total CO lbs (2 units)	99,000	116,216	50,440	104,550	370,206	185
Total VOC lbs (2 units)	11,352	13,140	5,720	13,600	43,812	22

*Assume this number of units operate simultaneously at condition stated with the remaining units operating at fully commissioned full output

Nat. Gas MMBtu/mmscf	1024		Siemens utilized fuel @ 23289 BTU/lb (HHV)
Number of GT Units	2		

(A) CTG is assumed to ramp at 3 MW per minute during Commissioning Operations

(B) Duration variable based on water steam cycle flushing and chemical cleaning. Days with continuous 24-hour operation were assumed in order to reduce the number of starts (and hence emissions), during various tests.

(C) Following SCR installation, NO_X values based on reduction of 50% from 60-70% load and 88.2% from 70-100% load.

(D) Following oxidation catalyst installation, CO values based on reduction of 10% from 30-40% load, 20% from 40-50% load, 30% from 50-70% load, and 50% from 70-100% load.

(E) Following oxidation catalyst installation, VOC values based on reduction of 10% from 10-30% load and 20% from 30-50% load.

Palmdale Energy Project-Subpart TTTT Compliance Calculations

Case/Run #	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Load, %	100	100	75	50	100	100	100	75	50	100	100	100	75	50	100
NG, btu/lb (HHV Gross)	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289
Total fuel flow, lbs/hr	97636	105934	78674	60929	94584	95400	103480	75804	58765	93633	95385	103463	75068	58250	83549
mmbtu/hr	2273.84	2467.10	1832.24	1418.98	2202.77	2221.77	2409.95	1765.40	1368.58	2180.62	2221.42	2409.55	1748.26	1356.58	1945.77
Mfg's CO2, lbs/hr	272172	295148	217149	166627	263683	265996	288350	209267	160745	261056	265923	288296	207265	159305	233000
Mfg's lbs CO2/mmbtu	119.70	119.63	118.52	117.43	119.71	119.72	119.65	118.54	117.45	119.72	119.71	119.65	118.56	117.43	119.75
EPA CO2 EF, lbs CO2/mmbtu	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888
EPA calculated, CO2 lbs/hr	265785	288374	214167	165861	257477	259698	281694	206354	159970	254888	259657	281647	204350	158568	227437
Net Power, MW/hr	669.60	714.40	516.60	370.50	650.20	656.40	699.40	503.00	361.70	643.60	656.30	699.40	498.10	358.30	566.40
Gross Power, MW/hr	686.40	732.00	532.30	383.20	666.90	673.10	716.90	518.60	376.40	660.30	673.00	716.90	513.80	373.00	582.60
lbs CO2/MW Net (Mfg)	813	826	841	899	811	810	825	832	889	811	810	824	832	889	823
lbs CO2/MW Gross (Mfg)	793	806	816	870	791	790	804	807	854	791	790	804	807	854	800

Case/Run #	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Load, %	100	100	75	50	100	100	100	75	53	40	43	43	50	100
NG, btu/lb (HHV Gross)	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289	23289
Total fuel flow, lbs/hr	93180	101396	68358	53474	80056	92091	100559	65603	53277	53921	53505	53440	53343	107210
mmbtu/hr	2170.07	2361.41	1591.99	1245.36	1864.42	2144.71	2341.92	1527.83	1240.77	1255.77	1246.08	1244.56	1242.31	2496.81
Mfg's CO2, lbs/hr	259781	282556	188735	146312	223269	256744	280284	181183	145935	146955	145967	145827	145914	298701
Mfg's lbs CO2/mmbtu	119.71	119.66	118.55	117.49	119.75	119.71	119.68	118.59	117.62	117.02	117.14	117.17	117.45	119.63
EPA CO2 EF, lbs CO2/mmbtu	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888	116.888
EPA calculated, CO2 lbs/hr	253655	276021	186084	145567	217929	250691	273742	178585	145031	146784	145652	145475	145211	291848
Net Power, MW/hr	633.60	677.10	440.50	317.90	533.80	620.00	664.30	414.60	313.20	312.70	318.80	319.30	316.70	719.80
Gross Power, MW/hr	650.20	694.50	455.70	332.30	549.70	636.60	681.60	429.60	327.60	327.00	333.20	333.70	331.10	737.40
lbs CO2/MW Net (Mfg)	820	835	857	920	837	828	844	874	932	940	916	913	921	830
lbs CO2/MW Gross (Mfg)	799	814	828	881	812	807	822	843	891	899	876	874	881	810

Siemens Performance Data Sheets, Summit-Palmdale, April 17/22, 2015.

EPA CO2 EF , 40 CFR 98, Subpart C, Table C-1. 53.02 kg CO2/mmbtu = 116.888 lbs CO2/mmbtu

lbs CO2/MW for both units

Appendix B- Road Segments Considered for Paving (PM_{10} Reduction)

Table 4.1G-2 Road Segments Considered for Paving (PM10 Reduction)

Street Segment	From	To	Jurisdiction	Street Type	Segment Length (Mi.)	ROW Req.	Segment Footprint (Acre)
Ave. B	90th Street W	30th Street W	L.A. County	County Road	Approx. 6.0	40 Ft.	29.1
Ave. S-2	96th Street E	106th Street E	L.A. County	County Road	Approx. 1.0	40 Ft.	4.85
110th Street E	Ave. L	Columbia Way /Avenue M	City of Palmdale	Secondary Arterial	Approx. 1.0	92 Ft.	11.15
40th Street W	Ave. N	Ave N-8	L.A. County	County Road	Approx. 0.5	40 Ft.	1.94
Ave. Q	90th Street E	110th Street E	City of Palmdale	Secondary Arterial	Approx. 2.0	92 Ft.	22.3
Ave. S-6	96th Street E	106th Street E	L.A. County	County Road	Approx. 1.0	40 Ft.	4.85
Ave. T-10	87th Street E	96th Street E	L.A. County	County Road	Approx. 1.0	40 Ft.	4.85
Ave. N-8	Bolz Ranch Road	30th Street W	City of Palmdale	Local Interior St.	Approx. 1.5	60 Ft.	10.91
Ave. G	90th Street E	120th Street E	L.A. County	County Road	Approx. 3.0	40 Ft.	9.70
Carson Mesa Road	El Sastre	Vincent View Road	L.A. County	County Road.	Approx. 1.85	40 Ft.	8.24