U.S. Environmental Protection Agency
Region 9 – Pacific Southwest

Prevention of Significant Deterioration Permit
Pursuant to Clean Air Act Title I, Part C and 40 CFR 52.21

PSD Permit:	SE 17-01
Permittee:	Palmdale Energy, LLC (subsidiary of Summit Power Group, LLC) 801 Second Ave., Suite 1150 Seattle, WA 98104
Source Name:	Palmdale Energy Project
Source Location:	950 East Avenue M, Palmdale CA - West of the NW corner of Air Force Plant 42, and East of the intersection of Sierra Highway and East Avenue M

Pursuant to the provisions of the Clean Air Act (CAA) in subchapter I, part C, and the Code of Federal Regulations (CFR) Title 40, Section 52.21, the United States Environmental Protection Agency Region 9 (EPA) is issuing a Prevention of Significant Deterioration (PSD) permit to Palmdale Energy, LLC (or Permittee). This permit applies to the construction and operation of a new natural gas-fired combined-cycle power plant known as the Palmdale Energy Project (PEP or Source).

Palmdale Energy, LLC is authorized to construct and operate the PEP as described herein, in accordance with its PSD permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR 52.21, and other terms and conditions set forth in this PSD permit. Failure to comply with any condition or term set forth in this permit may result in enforcement action pursuant to section 113 of the CAA. This permit does not relieve Palmdale Energy, LLC from the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR parts 51, 52, 60, 61, 63, and 72 through 75), or other federal, state, and local requirements.

Per 40 CFR 124.15(b), this permit shall become effective 30 days after the service of notice of the final permit decision unless review is requested on the final permit under 40 CFR 124.19.

Elizabeth J Adams
Elizabeth Adams
Acting Director, Air Division

April 25, 2018
Date

Source Description and Equipment List

The Source will have an electrical output of 645 megawatts (nominal output at average annual conditions).

The Source will be located on a parcel of land, currently zoned for industrial use, in the city of Palmdale, in Los Angeles County, California. The approximately 50-acre parcel is west of the northwest corner of Air Force Plant 42, and east of the intersection of Sierra Highway and East Avenue M. The Source is located within the Antelope Valley Air Quality Management District (AVAQMD).

This PSD permit requires the use of Best Available Control Technology (BACT) to limit emissions of nitrogen oxides (NO_X), carbon monoxide (CO), total particulate matter (PM), particulate matter less than or equal to 10 micrometers (µm) in diameter (PM_{10}), particulate matter less than or equal to 2.5 µm in diameter ($PM_{2.5}$), and greenhouse gases (GHG). This permit includes emission limits to ensure that air pollution emissions from the Source will not cause or contribute to violations of any National Ambient Air Quality Standards (NAAQS) or any applicable PSD increments for the pollutants regulated under this PSD permit.

Equipment List:

Emissions Unit	Description	Control Equipment Authorized by this Permit
GEN1	214 MW combustion turbine generator (CTG), with a maximum heat input rate of 2,217 MMBtu/hr (HHV, at ISO conditions); natural gas-fired Siemens SGT6-5000F; vents to a dedicated Heat Recovery Steam Generator (HRSG) and a 276 MW Steam Turbine Generator (STG) shared with GEN2; 160-ft stack height; 22-ft stack diameter	Dry Low-NO_X (DLN) combustors, selective catalytic reduction (SCR), an oxidation catalyst, and inlet air filtration
GEN2	214 MW CTG, with a maximum heat input rate of 2,217 MMBtu/hr (HHV, at ISO conditions); natural gas-fired Siemens SGT6-5000F; vents to a dedicated HRSG and a 276 MW STG shared with GEN1; 160-ft stack height; 22-ft stack diameter	DLN combustors, SCR, an oxidation catalyst, and inlet air filtration
DB1	193.1 MMBtu/hr (HHV) Duct Burner for GEN1, fired on natural gas	
DB2	193.1 MMBtu/hr (HHV) Duct Burner for GEN2, fired on natural gas	
D1	110 MMBtu/hr (HHV) Auxiliary Boiler fired on natural gas; 60-ft stack height; 3-ft stack diameter	Ultra-low-NO_X burner
D2	2,011 hp Emergency Generator Engine, fired on ultra-low sulfur diesel fuel; 20-ft stack height; 8-inch stack diameter	40 CFR Part 60, Subpart IIII emission standards
D3	140 hp Emergency Fire Pump Engine, fired on ultra-low sulfur diesel fuel; 19.5-ft stack height; 5-inch stack diameter	40 CFR Part 60, Subpart IIII emission standards
CB	Six enclosed-pressure SF_6 Circuit Breakers	10% (by weight) leak detection system
FUG	Fugitive methane from equipment leaks	Leak detection and repair program

Permit Terms and Conditions

Section 1: General Provisions

1. *Permit Expiration*
   As provided in 40 CFR 52.21(r), unless the PSD permitting authority issues an extension of time pursuant to 40 CFR 52.21(r)(2), this PSD permit shall become invalid if:
   a. Construction is not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months after the EPA's final PSD permit takes effect; or
   b. Construction is discontinued for a period of 18 months or more; or
   c. Construction is not completed within a reasonable time.

2. *Agency Notifications*
   The Permittee shall send all reports and notifications required to be submitted to the EPA by this permit to the mail and email addresses below. All reports and notifications sent by mail must be postmarked by the applicable due date identified in this permit. With prior written notification, the EPA may waive the requirement to submit a hardcopy by mail or may update the mail or emailing addresses specified below.

   EPA Region 9
   Director, Enforcement Division
   Attn: Air & TRI, ENF-2-1
   75 Hawthorne Street
   San Francisco, CA 94105-3901

   Email: AEO_R9@epa.gov

   With a copy to:
   Air Pollution Control Officer
   Antelope Valley Air Quality Management District
   (per the method(s) and address(es) specified for the Permittee's notifications to the AVAQMD in the Authority to Construct and/or title V operating permit issued by the AVAQMD to the Permittee)

3. *Initial Notifications*
   The Permittee shall notify the EPA of the:
   a. Date construction is commenced, within 30 days of such event;
   b. Actual date of initial startup, as defined in 40 CFR 60.2, within 15 days of such event;
   c. Date upon which initial performance tests will commence, in accordance with the provisions in Condition 41, not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol(s) required pursuant to Condition 40; and
   d. Date upon which initial performance evaluation of the continuous emissions monitoring system (CEMS) will commence in accordance with 40 CFR 60.13(c), not less than 30 days prior to such date. Notification may be provided with the submittal of the CEMS performance test protocol required pursuant to Condition 40.

4. *Source Operation*
   At all times, including periods of startup, shutdown, shakedown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the Source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA which may

include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the Source.

5. *Inspection and Entry*
The EPA Regional Administrator, and/or his or her authorized representative, upon the presentation of proper credentials, shall be permitted to:
   a. Enter upon the premises where the Source is located or emissions-related activity is conducted; or where records are required to be kept under the terms and conditions of this permit;
   b. Have access to and copy, at reasonable times, any records that are required to be kept under the conditions of this permit;
   c. Inspect, during normal business hours or while the Source is in operation, any facilities, equipment (including monitoring and air pollution control equipment), method, practices or operations regulated or required under this permit;
   d. Sample or monitor substances, emissions, or parameters subject to the requirements in this permit; and
   e. Record any inspection by use of written, electronic, magnetic and photographic media.

6. *Transfer of Ownership*
Prior to any transfer of ownership of the Source, the Permittee shall provide a copy of this permit to the new owner(s). In the event of any change in ownership of the Source, the Permittee must notify the EPA as soon as possible but in no case later than 30 days after the change in ownership is effective. This notification to the EPA must specify the date on which ownership was transferred, identify the previous owner, and update the name, street address, mailing address, contact information, and any other information about the ownership and/or operation of the Source that will change as a result of the change in ownership. The Permittee shall ensure that the Source remains in compliance with this permit during any such transfer of ownership.

7. *Severability*
The provisions of this permit are severable. If any portion of this permit is held invalid, the remaining terms and conditions of this permit shall remain valid and in force.

8. *Adherence to Application and Compliance with other Environmental Laws*
The Permittee shall construct the Source and operate equipment listed in this permit (see Equipment List above) in compliance with this permit, the application on which this permit is based, and all other applicable federal, state, and local air quality regulations. This permit does not release the Permittee from any liability for compliance with other applicable federal, state, and local environmental laws and regulations, including the Clean Air Act.

9. *Compliance*
The Permittee must comply with all provisions of this permit. Noncompliance with any permit provision is a violation of the permit and the CAA, and is grounds for an enforcement action.

10. *Unavailable Defense*
In an enforcement action, it shall not be a defense for the Permittee that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the provisions of this permit.

11. *Property Rights*
The permit does not convey any property rights of any sort or any exclusive privilege.

12. *Credible Evidence*
For establishing whether the Permittee violated or is in violation of any requirement of this permit, nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source

would have been in compliance with applicable requirements if the Permittee had performed the appropriate performance or compliance test or procedure.

13. *Shakedown Period*
The emission limits and requirements in Conditions 18, 19, and 22 shall not apply during the shakedown period. Shakedown is defined as the period beginning with initial startup, as defined in 40 CFR 60.2, and ending no later than initial performance testing, during which the Permittee conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the equipment. The shakedown period shall not exceed 180 consecutive days. The requirements of Condition 16 shall apply at all times.

14. *Notification of Closure*
The Permittee must submit a report of any permanent or indefinite closure to EPA in writing within 90 days after the cessation of any operations at the permitted source. It is not necessary to submit a report of closure for regular, seasonal closures.

15. *Signature Verifying Truth, Accuracy, and Completeness*
All reports required by this permit shall be signed by a responsible official as to the truth, accuracy, and completeness of the information. The report must state that, based on information and belief formed after reasonable inquiry, the statements and information are true, accurate, and complete. If the Permittee discovers that any reports or notification submitted to the reviewing authority contain false, inaccurate, or incomplete information, the Permittee shall notify the reviewing authority immediately and correct or amend the report as soon as is practicable.

Section 2: Emission Limitations and Work Practice Standards

16. *Air Pollution Control Equipment and Operation*
As soon as practicable following initial startup of the CTGs (startup as defined in 40 CFR 60.2) but prior to commencement of commercial operation (as defined in 40 CFR 72.2), and thereafter, except as allowed below in Condition 19, the Permittee shall install, operate, and maintain the SCR systems for control of NO_X emissions and the oxidation catalysts for control of CO emissions from GEN1 and GEN2. The Permittee shall also perform any necessary operations to minimize emissions so that emissions are at or below the emission limits specified in this permit for GEN1 and GEN2.

17. *Gaseous Fuel Requirements*
For each CTG (GEN1 and GEN2) and the auxiliary boiler (D1), the Permittee shall use California Public Utilities Commission (PUC)-quality natural gas. The sulfur content of the gas shall not exceed 0.20 grains per 100 dry standard cubic feet (dscf), based on a 12-month rolling average, and shall not exceed 1.0 grains per 100 dscf at any time.

18. *Combustion Turbine Generator (CTG) Emission Limits*
On and after the date of initial startup, the Permittee shall not discharge or cause the discharge of emissions from each CTG unit (GEN1 and GEN2) into the atmosphere in excess of the limits specified in this Condition 18. These limits do not apply to NO_X and CO emissions during startup and shutdown periods; instead, the limits in Condition 19 apply during such periods.
    a. Concentration-based limits:
        i. 2.0 ppmvd of NO_X @ 15% O_2 based on a 1-hr average;
        ii. 0.0048 lb/MMBtu of PM, PM_{10}, and $PM_{2.5}$ based on the average of three stack test runs; and
        iii. 928 lb/MWh_{net} of CO_2 based on a 12-month rolling average. This limit includes contributions from duct firing (DB1 and DB2, as applicable) and the MWh contribution from the steam turbine generator.

b. Mass-based limits:
    i. 18.5 lb/hr of NO_X with the associated duct burner firing (DB1 or DB2, as applicable) based on a 1-hr average;
    ii. 17.1 lb/hr of NO_X without the associated duct burner firing (DB1 or DB2, as applicable) based on a 1-hr average; and
    iii. 11.8 lb/hr of PM, PM_{10}, and $PM_{2.5}$ based on the average of three stack test runs.

c. CO Emission Limits – The Demonstration Period is defined as the first 5 years immediately following the commencement of commercial operations (as defined in 40 CFR 72.2).
    i. The Permittee shall design the CTGs to each achieve a CO emission rate of 1.5 ppmvd @ 15% O_2 and 7.8 lb/hr based on a 1-hr average without duct firing (DB1 or DB2, as applicable). Prior to beginning actual construction, the Permittee shall submit a design plan to the EPA demonstrating that the CTGs are designed to achieve such a rate and setting forth the measures that will be taken to maintain the oxidation catalyst system and optimize its performance.
    ii. During the Demonstration Period, the Permittee shall operate the CTGs according to the design plan submitted to the EPA described above in Condition 18.c.i. During the Demonstration Period, the Permittee shall not discharge or cause the discharge of CO emissions from either CTG unit (GEN1 or GEN2) into the atmosphere in excess of the following amounts, based on a 1-hr average:
        1. 2.0 ppmvd CO @ 15% O_2, and
        2. 11.3 lb/hr with duct firing (DB1 or DB2, as applicable) or 10.4 lb/hr without duct firing (DB1 or DB2, as applicable).
    iii. Following the Demonstration Period, the Permittee shall not discharge or cause the discharge of CO emissions from each CTG Unit (GEN1 or GEN2) into the atmosphere in excess of the following amounts based on a 1-hr average, except as specified in Condition 18.c.iv:
        1. 1.5 ppmvd @ 15% O_2 without duct firing (DB1 or DB2, as applicable);
        2. 2.0 ppmvd @ 15% O_2 with duct firing (DB1 or DB2, as applicable);
        3. 7.8 lb/hr without duct firing (DB1 or DB2, as applicable); and
        4. 11.3 lb/hr with duct firing (DB1 or DB2, as applicable).
    iv. If, during the Demonstration Period, the Permittee determines that the CO limits in Condition 18.c.iii.1 or 18.c.iii.3 are not feasible, the Permittee shall submit an application at least 6 months prior to the end of the Demonstration Period requesting a revision of such limit(s). Such application must contain data and information that demonstrates that the Source was operated according to the design plan identified above in Condition 18.c.i, as well as a technical justification explaining why such lower limits are not feasible. Upon the EPA's review of such an application (which will include an opportunity for public notice and comment), if the EPA determines that the data and information gathered during the Demonstration Period demonstrate that different CO limit(s) are necessary, the limits in Condition 18.c.iii.1 and/or 18.c.iii.3 will be revised accordingly. Provided that the application specified in this condition is postmarked at least 6 months prior to the end of the Demonstration Period, the corresponding emission limit(s) in Condition 18.c.ii.1 and/or 18.c.ii.2 shall remain in effect until the EPA evaluates the application and makes a final decision regarding the revision of the limits in Condition 18.c.iii.1 and/or 18.c.iii.3.

19. *CTG Requirements during Gas Turbine Startup and Shutdown (GEN1 and GEN2)*
The following limits apply separately to each CTG, GEN1 and GEN2:
    a. Startup is defined as the period beginning with ignition and lasting until either the equipment complies with the emission limits in Conditions 18.a.i, ii, and iii, as applicable, for 10 one-minute averaging periods or the maximum time allowed for the event after ignition as specified in Condition 19.c, whichever occurs first. Additionally:

i. A cold startup occurs when the STG rotor temperature is less than 485°F after a CTG shutdown;
ii. A warm startup occurs when the STG rotor temperature is greater than or equal to 485°F but less than 685°F after a CTG shutdown; and
iii. A hot startup occurs when the STG rotor temperature is greater than 685°F after a CTG shutdown.

b. Shutdown is defined as the period beginning with reducing fuel flow below normal operating mode and lasting until fuel flow is completely shut off and combustion has ceased.
c. The emissions of NO_X and CO during startup and shutdown events, and the duration of such events, shall not exceed the following, as verified by the CEMS:

	NO_X	CO	Duration
Cold Startup	51.5 lb/event	416 lb/event	39 minutes
Warm Startup	46.8 lb/event	378 lb/event	35 minutes
Hot Startup	43.2 lb/event	305 lb/event	30 minutes
Shutdown	33.0 lb/event	75.9 lb/event	25 minutes

d. During startup and shutdown periods, emissions of NO_X shall not exceed 53.6 lb/hr based on a 1-hr average.
e. During startup and shutdown periods, emissions of CO shall not exceed 419 lb/hr based on a 1-hr average.

20. *CTG Fuel Use Limit*
The total annual fuel use of natural gas for each CTG, GEN1 and GEN2, shall not exceed 1.735 x 10^{10} standard cubic feet (scf) per year based on a 12-month rolling total.

21. *Duct Burner Fuel Use Limit*
The total annual fuel use of natural gas for each duct burner (DB1 and DB2) shall not exceed 2.75 x 10^8 scf per year based on a 12-month rolling total. The Permittee shall ensure that the duct burners are not operated unless the associated gas turbine units are in operation.

22. *Auxiliary Boiler Emission Limits*
The Permittee shall not discharge or cause the discharge of emissions from the auxiliary boiler, unit D1, into the atmosphere in excess of the following, and shall otherwise comply with the following limits and specifications:
a. NO_X emissions shall not exceed 9 ppmvd @ 3% O_2 based on a 3-hr average;
b. CO emissions shall not exceed 50 ppmvd @ 3% O_2 based on a 3-hr average;
c. PM, PM_{10}, and $PM_{2.5}$ emissions shall not exceed 0.007 lb/MMBtu based on a 3-hr average;
d. As described in Condition 23, the Permittee shall perform a biennial boiler tune up;
e. Unit D1 shall not operate during normal operations of GEN1 or GEN2, except during periods of, or immediately following, startup. Unit D1 shall be shut down as soon as practicable after the completion of any startup process, as defined in Condition 19.a.
f. Total annual fuel use of natural gas for Unit D1 shall not exceed 5.25 x 10^8 scf per year based on a 12-month rolling total.

23. *Auxiliary Boiler Biennial Tune-ups*
Unit D1 shall undergo biennial tune-ups and meet the associated requirements of Condition 48 as follows (if the unit is not operating on the required date for a tune-up, the tune-up must be conducted within one week of the first startup following that date):
a. Inspect the burner, and clean or replace any components of the burner as necessary (the Permittee may delay the burner inspection until the next scheduled unit shutdown, but must inspect each burner at least once every 36 months).
b. Inspect the flame pattern, and adjust the burner as necessary to optimize the flame pattern. The adjustment shall be consistent with the manufacturer's specifications.

c. Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly (the Permittee may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection).
d. Optimize total emissions of carbon monoxide. This optimization shall be consistent with the manufacturer's specifications, and must be consistent with the NO_X emission limit in Condition 22.a.
e. Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made).
f. Tune-ups shall occur biennially and no later than 25 months from the previous year's tune-up. The first biennial tune-up shall occur no later than 25 months after initial startup of the equipment.

24. *Emergency Generator Engine*
For the emergency generator engine, unit D2, the Permittee shall install and operate an engine certified to the emission standards in 40 CFR 60 Subpart IIII for emergency engines, for all pollutants, for the same model year and maximum engine power. In addition, for unit D2, the following requirements and provisions shall apply:
a. The engine shall comply with the emissions standards to which the engine is certified for the life of the engine.
b. Except during an emergency, operation of unit D2 shall be limited to maintenance and testing purposes. Operation for maintenance and testing purposes shall not exceed 30 minutes per day and 26 hours in a 12-month rolling period;
c. An emergency is defined as providing electrical power for critical networks or equipment when electric power from the local utility (or normal power source) is interrupted;
d. The engine shall be equipped with a non-resettable hour meter;
e. The engine shall be model year 2011 or later;
f. The engine shall burn only nonroad diesel fuel; and
g. The engine shall not operate for maintenance and testing purposes during periods of startup or shutdown of GEN1 or GEN2.

25. *Emergency Fire Pump Engine*
For the emergency fire pump engine, unit D3, the Permittee shall install and operate an engine certified to the emission standards in 40 CFR 60 Subpart IIII for emergency fire pump engines, for all pollutants, for the same model year and maximum engine power. In addition, for unit D3, the following requirements and provisions shall apply:
a. The engine shall comply with the emissions standards to which the engine is certified for the life of the engine.
b. Except during an emergency, operation of unit D3 shall be limited to maintenance and testing purposes, including as required for fire safety testing. Operation for maintenance and testing purposes shall not exceed 60 minutes per day or 52 hours in a 12-month rolling period;
c. An emergency is defined as providing mechanical work to pump water in the case of fire;
d. The engine shall be equipped with a non-resettable hour meter;
e. The engine shall be model year 2011 or later;
f. The engine shall burn only nonroad diesel fuel; and
g. The engine shall not operate for maintenance and testing purposes during periods of startup or shutdown of GEN1 or GEN2.

26. *SF_6 Circuit Breakers*
a. The circuit breakers (CB) shall be enclosed-pressure SF_6 circuit breakers.
b. Emissions from the circuit breakers (CB) shall not exceed an annual leakage rate of 0.5% by weight (calendar year basis).
c. The circuit breakers (CB) shall be equipped with a 10% by weight leak detection system.

27. *Fugitive Methane Equipment Leaks*

The Permittee shall design and fully implement a leak detection and repair (LDAR) program to minimize fugitive methane leaks from natural gas piping and equipment, including from valves, flanges and compressors. At a minimum, the LDAR program shall comply with the following requirements:

a. Equipment in acoustical enclosures: Potential leaks from the acoustical enclosures housing the gas compression equipment and CTGs shall be monitored continuously by gas detection equipment, to detect any natural gas leaks, and, if a leak is detected, to activate an alarm and immediately isolate the natural gas supply external to the enclosures until the leak is repaired. This continuous monitoring equipment shall be installed, operated, and maintained consistent with manufacturer's recommendations, and undergo quality control/quality assurance checks at least annually.
b. For natural gas piping and other natural gas equipment: All piping shall be installed in accordance with Industry Codes and Standards (ASME B31.1 – Power Piping) and pressure tested after installation and prior to initial startup. In accordance with plant operating procedures, plant technicians will periodically inspect all piping, flanged connections, valves, and other natural gas equipment using hand held gas leak detection equipment. Such inspections shall occur at least each calendar quarter. All leaks will be repaired as soon as possible, and no later than 15 calendar days after discovery. A leak shall be defined as 10,000 ppmv of methane/natural gas. The methane/natural gas analyzer shall be operated and maintained consistent with manufacturer's recommendations, and undergo quality control/quality assurance checks at least annually.

Section 3: Monitoring and Testing Requirements

28. *Requirement for Continuous Emission Monitoring Systems (CEMS) for GEN1 and GEN2*
The Permittee shall install, calibrate, maintain, and operate a CEMS each for GEN1 and GEN2 that measures stack gas NO_X, CO, and either CO_2 or O_2 concentrations in ppmv. The concentrations of NO_X and CO shall be corrected to 15% O_2 on a dry basis. By no later than the end of the shakedown period, as defined in Condition 13, or upon the commencement of commercial operations (as defined in 40 CFR 72.2), whichever comes first, each CEMS for GEN1 and GEN2 shall be installed, certified, quality-assured and operated in accordance with Conditions 29 through 34, and as follows:
    a. Each CEMS shall meet the requirements of 40 CFR 60.13;
    b. Each CEMS shall be operated and data recorded during all periods of operation of GEN1 and GEN2 including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments;
    c. Each CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 1-minute clock-hour period; and
    d. The initial certification of the CEMS may either be conducted separately or as part of the initial performance test of each emission unit. The CEMS must undergo and pass initial performance specification testing on or before the date of the initial performance test.

29. *NO_X CEMS per Part 75*
If the Permittee has installed a NO_X CEMS to meet the requirements of 40 CFR part 75 and meets the ongoing requirements of 40 CFR part 75, that CEMS may be used to meet the requirements of Condition 28, except that the owner or operator shall also meet the requirements of Conditions 48 and 52. Data reported to meet the requirements of Condition 52 shall not include data substituted using the missing data procedures in subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

30. *Continuous Flow Monitoring System*
    a. The Permittee shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of 40 CFR part 60, appendix B and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of 40 CFR part 60, appendix F, and record the output of the system, for measuring the volumetric flow rate of exhaust gases

discharged to the atmosphere. If the Permittee uses a Type-S pitot tube or a pitot tube assembly for the flow RATAs, the pitot tube or pitot tube assembly must be calibrated, and the 0.84 default Type-S pitot tube coefficient specified in Method 2 shall not be used; or

b. Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20(c) and appendix A to 40 CFR part 75, and continuing to meet the applicable quality control and quality assurance requirements of 40 CFR 75.21 and appendix B to 40 CFR part 75, may be used. Flow rate data reported to meet the requirements of Conditions 48 and 52 shall not include substitute data values derived from the missing data procedures in subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75. If the Permittee uses a Type-S pitot tube or a pitot tube assembly for the flow RATAs, the pitot tube or pitot tube assembly must be calibrated, and the 0.84 default Type-S pitot tube coefficient specified in Method 2 shall not be used.

31. *Procedures for NO_X CEMS*

Each NO_X CEMS shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to 40 CFR part 60 or according to the procedures in appendices A and B to 40 CFR part 75, as applicable. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to 40 CFR part 60, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to 40 CFR part 60, shall be submitted with each compliance report required under Condition 52.

a. Alternatively, for span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to 40 CFR part 75, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to 40 CFR part 60. If this option is selected: the frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to 40 CFR part 75 shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to 40 CFR part 75 shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to 40 CFR part 60; and the grace period provisions in section 2.2.4 of appendix B to 40 CFR part 75 shall apply. For the purposes of data validation, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to 40 CFR part 60 shall be performed for NO_X span values less than or equal to 30 ppm.

b. Alternatively, RATAs may be performed in accordance with section 2.3 of appendix B to 40 CFR part 75 instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to 40 CFR part 60. If this option is selected: the frequency of each RATA shall be as specified in section 2.3.1 of appendix B to 40 CFR part 75; the applicable relative accuracy specifications shown in Figure 2 in appendix B to 40 CFR part 75 shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to 40 CFR part 75 shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to 40 CFR part 60; and the grace period provisions in section 2.3.3 of appendix B to 40 CFR part 75 shall apply. For the purposes of data validation, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to 40 CFR part 60 shall be met.

32. *CO_2 Emissions Monitoring*

The Permittee must determine the hourly CO_2 mass emissions in tons from units GEN1 and GEN2 as specified below:

a. The Permittee must, install, certify, operate, maintain, and calibrate a CO_2 CEMS to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere. As an alternative to direct measurement of CO_2 concentration, data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations may be used, in accordance with 40 CFR 75.10(a)(3)(iii). If CO_2 concentration is measured on a dry basis, the Permittee must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR part 75. Alternatively, an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) may be used.

b. For each continuous monitoring system that is used to determine the CO_2 mass emissions, the Permittee must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.
c. The Permittee must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from units GEN1 and GEN2, and must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.
d. The permittee must select an appropriate reference method to set up (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If the Permittee uses a Type-S pitot tube or a pitot tube assembly for the flow RATAs, the pitot tube or pitot tube assembly must be calibrated, and the 0.84 default Type-S pitot tube coefficient specified in Method 2 shall not be used.
e. The hourly CO_2 ton/hr values and CTG operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). These data must be used to calculate the hourly CO_2 mass emissions. Hourly ton/hr data shall be converted to lb/hr (by multiplying by 2000).
f. The Permittee must apportion the combined hourly net output from the STG to the individual CTG (GEN1 or GEN2) according to the fraction of the total heat input contributed by each CTG, including its associated duct burner.

33. *Procedures for CO CEMS*
Each CO CEMS must be installed, certified, maintained, and operated as follows:
a. The CEMS shall be operated according to Performance Specification 4A in appendix B of 40 CFR part 60;
b. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to 40 CFR part 60, and a DAR, prepared according to section 7 of Procedure 1 in appendix F to 40 CFR part 60, shall be submitted with each compliance report required under Condition 52;
c. During each relative accuracy test run of the CEMS required by Performance Specification 4 in appendix B of 40 CFR part 60, CO and O_2 (or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the following tests:
    i. For CO, EPA Reference Method 10, 10A, or 10B shall be used; and
    ii. For O_2 or CO_2, EPA Reference Method 3, 3A, or 3B, or ASME PTC-19-10-1981—part 10 (incorporated by reference, see 40 CFR 60.17 of subpart A of 40 CFR part 60), as applicable, shall be used.

34. *Monitoring Plans for CEMS and Continuous Flow*
At least 90 days before commencing certification testing of the monitoring systems, the Permittee shall prepare and submit to the EPA a unit-specific monitoring plan for each monitoring system for GEN1 and GEN2. The plan must be consistent with the monitoring requirements specified for GEN1 and GEN2 in Section 3 of this permit, and otherwise consistent will all other applicable requirements of this permit, including the applicable emission limits and standards in Section 2 of this permit. The Permittee shall comply with the requirements in the plan. The plan shall be updated and resubmitted as needed or upon request by the EPA. The plan must address the following requirements:
a. Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);
b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;
c. Performance evaluation procedures and acceptance criteria (e.g., calibrations, RATAs);
d. Ongoing operation and maintenance procedures in accordance with the general requirements of 40 CFR 60.13(d) or 40 CFR part 75 (as applicable);
e. Ongoing data quality assurance procedures in accordance with the general requirements of 40 CFR 60.13 or 40 CFR part 75 (as applicable); and
f. Ongoing recordkeeping and reporting procedures in accordance with the requirements of this permit.

35. *SCR Monitoring*
Prior to the date of initial startup of units GEN1 and GEN2, the Permittee shall install, and thereafter maintain and operate, continuous monitoring and recording systems according to 40 CFR 60.13 to measure and record the following operational parameters:
    1. The ammonia injection rate of the ammonia injection system of each SCR system; and
    2. Exhaust gas temperature at the inlet to the SCR reactor.

36. *Electrical Output Monitoring*
For each CTG (GEN1 and GEN2) and its associated STG, the Permittee shall install, calibrate, maintain, and operate a wattmeter to measure net energy output in MWh on a continuous basis; and record the output of the monitor. Gross energy output, mechanical output and useful thermal output shall have the same meaning as in 40 CFR 60.5580. These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20.

37. *Calculating Compliance with CO_2 Standard for the CTGs*
The Permittee shall calculate the 12-month rolling average of pounds of CO_2 per MWh(net) as follows:
a. Each monthly compliance period shall include only "valid operating hours" in the compliance period, *i.e.,* operating hours for which:
    i. "Valid data" (as defined in §60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (pounds); and
    ii. The corresponding hourly net energy output value is also valid data (For hours with no useful output, zero is considered to be a valid value).
b. The Permittee must exclude operating hours in which:
    i. The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input; or
    ii. An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or
    iii. The total net energy output (P_{net}) is unavailable.
c. For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in Condition 37.a.
d. The Permittee must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values for all of the valid operating hours in the compliance period.
e. For each valid operating hour of the compliance period that is used to calculate the total CO_2 mass emissions, the Permittee must determine P_{net} (the corresponding hourly net energy output in MWh) as follows:
    i. For an operating hour in which a valid CO_2 mass emissions value is determined, if there is no net electrical output, but there is mechanical or useful thermal output, the Permittee must still determine net energy output for that hour.
    ii. For an operating hour in which a valid CO_2 mass emissions value is determined, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, the Permittee must use that hour in the compliance determination.
    iii. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.
    iv. P_{net} is determined by summing the electrical and mechanical energy output of the steam turbine, CTG, and any integrated auxiliary equipment, and subtracting any electric energy used for any auxiliary loads.

38. On an hourly basis for each duct burner, units DB1 and DB2, the Permittee shall measure and record, in accordance with 40 CFR 60.13, (1) the actual heat input and (2) the heat input corrected to ISO standard day conditions (288 degrees Kelvin, 60 percent relative humidity, and 101.3 kPa pressure).

39. The Permittee shall monitor, for GEN1 and GEN2 (including operation of units DB1 and DB2), the pounds of CO_2 per heat input (lb CO_2/MMBtu) corrected to ISO standard day conditions on (1) an hourly basis and (2) a 30-day rolling average basis. The 30-day rolling average shall be based on the average hourly lb/MMBtu recordings.

40. *Performance Tests Protocols*
The Permittee shall submit a performance test protocol for all performance tests, including for CEMS testing and RATAs, to the EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol and any changes required by the EPA.

41. *Performance Tests*
   a. The Permittee shall conduct performance tests (as described in 40 CFR 60.8) as follows:
      i. Within 60 days after achieving normal operation, but not later than 180 days after the initial startup of equipment, the Permittee shall conduct performance tests for NO_X, CO, CO_2, PM, PM_{10}, and $PM_{2.5}$ emissions from each gas turbine (Units GEN1/DB1 and GEN2/DB2). Units GEN1/DB1 and GEN2/DB2 shall also be performance tested annually thereafter (within 30 days before or after the previous performance test anniversary); and
      ii. Within 60 days after achieving normal operation, but not later than 180 days after the initial startup of equipment, the Permittee shall conduct performance tests for NO_X, CO, PM, PM_{10}, and $PM_{2.5}$ emissions from the 110 MMBtu/hr auxiliary boiler (D1). Unit D1 shall also be performance tested at least every five years thereafter (within 30 days before or after the previous performance test anniversary).
   b. For each engine (D2 and D3), the Permittee shall conduct performance tests to demonstrate compliance with the standards in Conditions 24 and 25 (according to 40 CFR 60.8 and 40 CFR part 60, subpart IIII) every 5,000 hours of operation. The performance test shall be conducted within 60 days of reaching each 5,000-hour interval.
   c. Performance tests shall be conducted in accordance with the test methods set forth in 40 CFR 60.8 and 40 CFR Part 60 Appendix A, as modified below. In lieu of the specified test methods, equivalent methods may be used with prior written approval from the EPA. Specifically, the Permittee shall use:
      i. EPA Method 7E for NO_X emissions;
      ii. EPA Method 10 for CO emissions;
      iii. EPA Method B for CO_2 emissions;
      iv. EPA Methods 5 and 202, or Methods 201A and 202, for filterable and condensable PM, PM_{10}, and $PM_{2.5}$, respectively, collecting a minimum of 120 dry standard cubic feet per test run; and
      v. The provisions of 40 CFR 60.8(f).
   d. In meeting the requirements in Conditions 41.a, the Permittee may conduct the performance testing during RATA testing of the applicable CEMS.
   e. In limited circumstances, upon written request and with adequate justification from the Permittee, the EPA may waive a specific annual test and/or allow for testing to be done at less than maximum operating capacity. Such justification must demonstrate to the EPA's satisfaction that it would be impractical to conduct the required test at the specified interval or to operate at maximum operating capacity during testing, as applicable. Any waiver or allowance granted by the EPA shall be approved in writing and the Permittee shall adhere to any specifications or requirements concerning such waiver or allowance that the EPA imposes therein.
   f. For performance test purposes, sampling ports, platforms, and access shall be provided on the emission unit exhaust system in accordance with the requirements of 40 CFR 60.8(e).
   g. The Permittee shall furnish the EPA with a written report of the results of performance tests within 60 days of

completion, and in accordance with Condition 53.

42. For each CTG, GEN1 and GEN2, the Permittee shall install, calibrate, maintain and operate a non-resettable totalizing volumetric fuel flow meter for each fuel line. The flow meter shall be maintained according to requirements in 40 CFR 60.13.

43. For each CTG, GEN1 and GEN2, the Permittee shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor. The monitors shall be operated and maintained according to the requirements in 40 CFR 60.13.

44. *Fuel Testing*
The Permittee shall take monthly samples of the natural gas combusted at the Source. The samples shall be analyzed for sulfur content using an ASTM method. The sulfur content test results shall be retained onsite and taken to ensure compliance with Condition 17.

45. *Monitoring for Auxiliary Equipment*
    a. The Permittee shall install and maintain a non-resettable totalizing volumetric flow meter in each fuel line for the auxiliary boiler, unit D1.
    b. The Permittee shall install and maintain a non-resettable elapsed time meter for each of the engines – units D2 and D3.
    c. The Permittee shall install and maintain a leak detection system on the circuit breakers (CB) that signals an alarm in the Source's control room in the event that any circuit breaker loses more than 10% of its dielectric fluid. The owner/operator shall promptly (1) respond to any such alarm, (2) investigate the circuit breaker involved, and (3) fix any leak-tightness problems that caused the alarm.

Section 4: Recordkeeping Requirements

46. All records required by this permit shall be retained for not less than five years following the date of the relevant measurements, maintenance reports, and/or records.

47. The Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the Source in a permanent form suitable for inspection including, but not limited to, the following:
    a. All records or reports pertaining to adjustments and/or maintenance performed on any system or device at the Source;
    b. All records relating to performance tests and monitoring for each emissions unit;
    c. All reports and notifications submitted;
    d. Records demonstrating compliance with each emission limit in Section 2, including any calculations or supporting information used to determine compliance;
    e. Records of maintenance performance on any system or device at the Source, including a maintenance log as described in Condition 50;
    f. Date, time, and duration of each startup and shutdown event for units GEN1 and GEN2, including whether the startup was a cold, warm, or hot startup.
    g. Emissions of NO_X and CO associated with each startup and shutdown event as measured by the CEMS;
    h. Identification of the times when the pollutant concentration exceeded full span of a CEMS;
    i. For any periods for which NO_X, CO, or CO_2 emissions data are not available, the Permittee shall submit to the EPA a signed statement indicating whether any changes were made in operation of the emission control system during the period of data unavailability; operations of the control system and affected emission unit(s) during

periods of data unavailability are to be compared with operation of the control system and affected emission unit(s) before and following the period of data unavailability;

j. Description of any modifications to CEMS which could affect the ability of the CEMS to comply with the applicable performance specification;
k. Results of monthly natural gas fuel testing;
l. Monthly hours of operation for the duct burners and auxiliary boiler (units DB1, DB2, and D1), including the resulting rolling 12-month total;
m. Monthly hours of operation for the emergency engines (units D2 and D3) including the resulting calendar year total;
n. Documentation of engine certification for each engine (units D2 and D3);
o. For each diesel fuel delivery, documents demonstrating that nonroad diesel fuel was purchased;
p. Pounds of dielectric fluid added to the circuit breakers each month, and the current total annual leak rate, based on the assumption that all added dielectric fluid replaced fluid that was leaked, for purposes of complying with Condition 26;
q. Documentation of installation, testing, monitoring, maintenance, and repairs associated with the LDAR program accordance with the requirements of Condition 27; and
r. All other information required by this permit.

48. For each continuous monitoring system, the Permittee shall maintain records of the occurrence and duration of any startup, shutdown, shakedown, or malfunction, performance testing, evaluations, calibrations, checks, adjustments, maintenance, duration of any periods during which a continuous monitoring system or monitoring device is inoperative, and corresponding emission measurements. A period of monitor down-time shall be any unit operating clock hour in which sufficient data are not obtained by the CEMS to validate the hour for NO_X, CO, CO_2, or O_2, while the CEMS is also meeting the requirements of Condition 28.a.

49. For each biennial tune-up of the auxiliary boiler, unit D1, the Permittee shall maintain onsite a report containing the information below:
    a. The concentrations of CO in the effluent stream of the boiler in parts per million, by volume, and oxygen in volume percent, measured before and after the tune-up of the boiler;
    b. A description of any corrective actions taken as a part of the tune-up of the boiler; and
    c. The amount of fuel used over the 12 months prior to the biennial tune-up of the boiler.

50. The Permittee shall maintain a log describing the maintenance and repair activities for all emission units and control equipment, including the following information:
    a. Date of activity;
    b. Description of activity;
    c. For scheduled maintenance, the elapsed time, hours of operation, or other applicable measure since the activity was last performed;
    d. For scheduled maintenance, the elapsed time, hours of operation, or other applicable measure until the activity should next be performed; and
    e. For each CTG (GEN1 and GEN2), the activities associated with a maintenance plan that ensures regular maintenance intervals, consistent with manufacturer's recommendations, for minimizing recoverable losses in turbine efficiency.

Section 5: Reporting Requirements

51. The Permittee shall submit a report of all excess emissions and any other noncompliance with the conditions and requirements of this permit to the EPA for each six-month reporting period from January 1 to June 30 and from July 1 to December 31, except when more frequent reporting is required by an applicable subpart, or when the EPA, on a

case-by-case basis, determines and informs the Permittee that more frequent reporting is necessary to accurately assess the compliance status of the Source, in which case the Permittee shall comply with the more frequent reporting requirement specified by the EPA. Each report shall be postmarked by the 30th day following the end of each six-month reporting period and shall include, but not be limited to, the following:

a. Time intervals, data, and magnitude of the excess emissions;
b. Nature and cause of the excess emissions (if known);
c. Corrective actions taken and preventive measures adopted;
d. Applicable time and date of each period during which the CEMS was inoperative (monitor down-time), except for zero and span checks, and the nature of CEMS repairs or adjustments;
e. If applicable, a statement in the report specifying that no excess emissions occurred and/or that the monitoring equipment has not been inoperative, repaired, or adjusted;
f. Any failure to conduct any required source testing, monitoring, or other compliance activities;
g. Any violation of limitations on operation, including but not limited to restrictions on hours of operation.

Excess emissions shall be defined as any period in which an emissions unit (listed in the Equipment List above) exceeds any emission limits set forth in Section 2 of this permit. Excess emissions indicated by the CEMS, performance testing, or compliance monitoring shall be considered violations of the applicable emission limit for the purposes of this permit.

52. *Records for CEMS*

For each report submitted to the EPA according to Condition 51, the Permittee shall submit a signed statement indicating whether:

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified in this permit;
b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this permit and is representative of plant performance;
c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable; and
d. Whether compliance with the applicable emission limit has or has not been achieved during the reporting period.

53. *Performance Tests Reports*

The Permittee shall submit a test report, including for RATAs conducted for CEMS, to the EPA within 60 days after the completion of any required performance test. At a minimum, the test report shall include:

a. A description of the emissions unit and sampling location(s);
b. The time and date of each test;
c. A summary of test results, reported in units consistent with the applicable standard;
d. A description of the test methods and quality assurance procedures used;
e. A summary of any deviations from the proposed test plan and justification for why the deviation(s) was necessary;
f. The amount of fuel burned, raw material consumed, and/or product produced during each test run;
g. Operating parameters of the emission unit(s) being tested and applicable control equipment during each test run;
h. Sample calculations of equations used to determine test results in the appropriate units; and
i. The name of the company or entity performing the analysis.

54. *Malfunction Report*

a. The Permittee shall notify the EPA by email within two (2) working days following the discovery of any failure of equipment listed in this permit (see Equipment List above), or failure of a process listed in this permit to operate in a normal manner, which results in an increase in emissions above any allowable emission limit stated in Section 2 of this permit.

b. The Permittee shall provide an additional notification to the EPA within 15 days of any such failure described in Condition 54.a. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section 2, and the methods utilized to mitigate emissions and restore normal operations.

c. Compliance with the malfunction notification provision in Condition 54.b shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

Attachment A: Abbreviations and Acronyms

AQMD	Air Quality Management District
ASTM	American Society for Testing and Materials
BACT	best available control technology
Btu	British thermal unit
CAA	Clean Air Act
CD	calibration drift
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CGA	cylinder gas audits
CO	carbon monoxide
CO_2	carbon dioxide
CTG	combustion turbine generator
DAR	data assessment report
District	Antelope Valley Air Quality Management District
DLN	dry low NO_X
EPA	Environmental Protection Agency, Region 9
g	grams
GHG	greenhouse gas
gr	grains
HHV	higher heating value
HRSG	heat recovery steam generator
hp	horsepower
hr	hour
kPa	kilopascals
kW	kilowatt
lb	pounds
lbs	pounds
MMBtu	million British thermal units
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NO_2	nitrogen dioxide
NO_X	oxides of nitrogen
NSPS	New Source Performance Standards
O_2	oxygen
PEP	Palmdale Energy Project
PM	total particulate matter
$PM_{2.5}$	particulate matter with aerodynamic diameter less than or equal to 2.5 micrometres
PM_{10}	particulate matter with aerodynamic diameter less than or equal to 10 micrometres
ppm	parts per million
ppmvd	parts per million by volume, dry basis
ppmv	parts per million by volume
PSD	Prevention of Significant Deterioration
PUC	Public Utilities Commission
RATA	relative accuracy test audit
scf	standard cubic feet
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
STG	steam turbine generator
tpy	tons per year
yr	Year
µm	micrometer