Exhibit 8

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT ISSUED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION IX

PSD PERMIT NUMBER: SE 09-01

PERMITTEE: City of Palmdale
38300 Sierra Highway, Suite A
Palmdale, CA 93550

FACILITY NAME: Palmdale Hybrid Power Project

FACILITY LOCATION: 950 East Avenue M
Palmdale, CA

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 7470, *et. seq.*), 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 the City of Palmdale. The Permit applies to the construction and operation of a new 570 megawatt (MW, nominal) natural gas-fired combined-cycle power plant, with an integrated 50 MW solar-thermal plant, known as the Palmdale Hybrid Power Project (PHPP) in Palmdale, California.

The City of Palmdale is authorized to construct and operate the PHPP power plant as described herein, in accordance with the 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 PSD Permit may result in enforcement action pursuant to Section 113 of the Clean Air Act. This PSD Permit does not relieve the City of Palmdale from the responsibility to comply with any other applicable provisions of the Clean Air Act (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 63, and 72 through 75), or other federal, state, and Antelope Valley Air Quality Management District requirements.

Per 40 CFR § 124.15(b), this PSD Permit becomes effective 30 days after the service of notice of this final permit decision unless review is requested on the permit pursuant to 40 CFR § 124.19.

For Kerry Drake
Deborah Jordan
Director, Air Division

10/18/11
DATE

PALMDALE HYBRID POWER PROJECT (SE 09-01)
PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
PERMIT CONDITIONS

PROJECT DESCRIPTION

The Palmdale Hybrid Power Project (Project) consists of two General Electric (GE) Frame 7FA natural gas-fired combustion turbine-generators (CTGs) rated at 154 megawatt (MW, gross) each, two heat recovery steam generators (HRSGs), one steam turbine generator (STG) rated at 267 MW, and 251 acres of parabolic solar-thermal collectors with associated heat-transfer equipment. The Project will have an electrical output of 570 MW (nominal) or 563 MW (net). The Project will be located on a parcel of land owned by the city of Palmdale, currently zoned for industrial use, in Los Angeles County. The approximately 333-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 City of Palmdale is located within the Antelope Valley Air Quality Management District (District).

This Prevention of Significant Deterioration (PSD) permit for the Project 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 under 10 micrometers (μm) in diameter (PM_{10}), particulate matter under 2.5 (μm) in diameter ($PM_{2.5}$), and greenhouse gases (GHG), to the greatest extent feasible. Air pollution emissions from the Project would not cause or contribute to violations of any National Ambient Air Quality Standards (NAAQS) or any applicable PSD increments for the pollutants regulated under the PSD permit.

Additional equipment includes auxiliary equipment including a natural gas heater and boiler, a diesel-fired emergency generator and emergency firewater pump engine, cooler towers, and circuit breakers.

EQUIPMENT LIST

The following devices and activities are subject to this PSD permit:

Unit ID	Description
GEN1	• 154 MW (gross) combustion turbine generator (CTG), with a maximum heat input rate of 1,736 MMBtu/hr (HHV) • Natural gas-fired GE Model Frame 7FA Rapid Start Process CTG • Vented to a dedicated Heat Recovery Steam Generator (HRSG) and a 267 MW Steam Turbine Generator (STG) shared with GEN2 • Integrated (through the HRSG and STG) with a 251-acre solar-thermal plant (STP) consisting of parabolic solar-thermal collectors and associated heat-transfer equipment designed to contribute up to 50 MW of generation from the STG • Emissions of NO_x and CO controlled by Dry Low-NO_X (DLN) Combustors, Selective Catalytic Reduction (SCR), and an Oxidation Catalyst (Ox-Cat)
GEN2	• 154 MW (gross) combustion turbine generator (CTG), with a maximum heat input rate of 1,736 MMBtu/hr (HHV) • Natural gas-fired GE Model Frame 7FA Rapid Start Process CTG • Vented to a dedicated Heat Recovery Steam Generator (HRSG) and a 267 MW Steam Turbine Generator (STG) shared with GEN2 • Integrated (through the HRSG and STG) with a 251-acre solar-thermal plant (STP) consisting of parabolic solar-thermal collectors and associated heat-transfer equipment designed to contribute up to 50 MW of generation from the STG • Emissions of NO_x and CO controlled by Dry Low-NO_X (DLN) Combustors, Selective Catalytic Reduction (SCR), and an Oxidation Catalyst (Ox-Cat)
DB1	• 500 MMBtu/hr (HHV) Duct Burner for GEN1, fired on natural gas
DB2	• 500 MMBtu/hr (HHV) Duct Burner for GEN2, fired on natural gas
D1	• 110 MMBtu/hr (HHV) Auxiliary Boiler with ultra low-NO_X burner, fired on natural gas
D2	• 2,000 kW (2,683 hp) Emergency Internal Combustion (IC) Engine, fired on Diesel fuel • 40 CFR Part 60, Subpart IIII emission standards • California Air Resources Board Tier 2 emission standards
D3	• 182 hp (135 kW) Emergency Diesel-fired IC Engine Firewater Pump Engine • 40 CFR Part 60, Subpart IIII emission standards • California Air Resources Board Tier 3 emission standards

Unit ID	Description
D4	• 40 MMbtu/hr (HHV) Auxiliary Heater with ultra low-NO_X burner, fired on natural gas
D5	• Cooling tower with 130,000 gallons per minute maximum circulation rate • Total dissolved solids (TDS) concentration in makeup water of 5,000 ppm (531 mg/L) • Drift eliminator with drift losses less than or equal to 0.0005 percent based on circulation rate
CB	• Enclosed-pressure SF_6 Circuit Breakers • 0.5% (by weight) annual leakage rate • 10% (by weight) leak detection system
MV	• Maintenance vehicles generating fugitive road dust when traveling on paved and unpaved roadways in the solar field for the Project • Project Fugitive Dust Control Plan

PERMIT CONDITIONS

I. PERMIT EXPIRATION

As provided in 40 CFR § 52.21(r), this PSD Permit shall become invalid if construction:

A. is not commenced (as defined in 40 CFR § 52.21(b)(9)) within 18 months after the approval takes effect; or

B. is discontinued for a period of 18 months or more; or

C. is not completed within a reasonable time.

II. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region IX by letter or by electronic mail of the:

A. date construction is commenced, postmarked within 30 days of such date;

B. actual date of initial startup, as defined in 40 CFR § 60.2, postmarked within 15 days of such date;

C. date upon which initial performance tests will commence, in accordance with the provisions of Condition X.G, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition X.G; 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), postmarked 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 X.F.

III. FACILITY OPERATION

A. At all times, including periods of startup, shutdown, shakedown, and malfunction, Permittee shall, to the extent practicable, maintain and operate the Facility, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA, which may include, but is not limited to, monitoring results, opacity observations, review of operating maintenance procedures and inspection of the Facility.

B. The Permittee shall operate and maintain the STP in a manner consistent with good engineering practices for its full utilization.

C. As soon as practicable following initial startup of the power plant (as defined in 40 CFR § 60.2) but prior to commencement of commercial operation (as defined in 40 CFR § 72.2), and thereafter, the Permittee shall develop and implement an operation and maintenance plan for the STP, consistent with Condition III.B above. At a minimum, the plan shall identify measures for assessing the performance of the STP, the acceptable range of the plant performance measures for achieving the design electrical output, the methods for monitoring the plant performance measures, and the routine procedures for maintaining the STP in good operating condition.

IV. MALFUNCTION REPORTING

A. Permittee shall notify EPA at R9.AEO@epa.gov within two (2) working days following the discovery of any failure of air pollution control equipment or process equipment, or failure of a process to operate in a normal manner, which results in an increase in emissions above the allowable emission limits stated in Section X of this permit.

B. In addition, Permittee shall provide an additional notification to EPA in writing or electronic mail within fifteen (15) days of any such failure described under Condition IV.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 X, and the methods utilized to mitigate emissions and restore normal operations.

C. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

V. RIGHT OF ENTRY

The EPA Regional Administrator, and/or an authorized representative, upon the presentation of credentials, shall be permitted:

A. to enter the premises where the Facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

B. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

C. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and

D. to sample materials and emissions from the source(s).

VI. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the Facility, this PSD Permit shall be binding on all subsequent owners and operators. Within 14 days of any such change in control or ownership, Permittee shall notify the succeeding owner and operator of the existence of this PSD Permit and its conditions by letter. Permittee shall send a copy of this letter to EPA Region IX within thirty (30) days of its issuance.

VII. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

VIII. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct the Project in compliance with this PSD permit, the application on which this permit is based, and all other applicable federal, state, and local air quality regulations. This PSD 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.

IX. RESERVED

X. SPECIAL CONDITIONS

A. Annual Facility Emission Limits

1. Annual emissions, in tons per year (tpy) on a 12-month rolling average basis, shall not exceed the following:

	NO_x	CO	PM	PM_{10}	$PM_{2.5}$
Total Facility	**114.9 tpy**	**244.1 tpy**	**111.1tpy**	**94.5tpy**	**88.0**

	CO_2e
Total Facility	**1,913,000 tpy**

2. Only Public Utilities Commission (PUC)-quality pipeline natural gas shall be fired at this Facility. PUC-quality pipeline natural gas shall not exceed a sulfur content of 0.20 grains per 100 dry standard cubic feet on a 12-month rolling average basis and shall not exceed a sulfur content of 1.0 grains per 100 dry standard cubic feet, at any time.

B. Air Pollution Control Equipment and Operation

As soon as practicable following initial startup of the power plant (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 noted below in Condition X.D, Permittee shall install, continuously operate, and maintain the SCR systems for control of NO_X and the Ox-Cat systems for control of CO for Units GEN1 and GEN2. Permittee shall also perform any necessary operations to minimize emissions so that emissions are at or below the emission limits specified in this permit.

C. Combustion Turbine Generator (CTG) Emission Limits

1. Except as noted below under Condition X.D, on and after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from each CTG Unit (of GEN1 and GEN2) into the atmosphere in excess of the following:

	Emission Limit (per CTG) (no duct burning)	Emission Limit (per CTG) (with duct burning)
NO_x	• 13.47 lb/hr • 1-hr average • 2.0 ppmvd @ 15% O_2	• 16.60 lb/hr • 1-hr average • 2.0 ppmvd @ 15% O_2
CO	3-Year Demonstration Period • 8.20 lb/hr • 1-hr average • 2.0 ppmvd @ 15% O_2 Post-Demonstration Period • 6.15 lb/hr • 1-hr average • 1.5 ppmvd @ 15% O_2 Conditions in X.C.3 may affect the timing and applicability of post-demonstration period emission limits.	• 10.10 lb/hr • 1-hr average • 2.0 ppmvd @ 15% O_2
PM, PM_{10}, $PM_{2.5}$	• 0.0048 lb/MMBtu • 8.46 lb/hr • 9-hr average • PUC-quality natural gas (Sulfur content of no greater than 0.20 grains per 100 dscf on a 12-month average and not greater than 1.0 gr/dscf at any time)	• 0.0049 lb/MMBtu • 11.3 lb/hr • 9-hr average • PUC-quality natural gas (Sulfur content of no greater than 0.20 grains per 100 dscf on a 12-month average and not greater than 1.0 gr/dscf at any time)
GHG	• 774 lb CO_2/MWh source-wide net output • 7,319 Btu/kWh source-wide net heat rate • 365-day rolling average	

2. The hours of operation for each duct burner (DB1 and DB2) shall not exceed 2,000 hours per 12-month rolling average. Permittee shall ensure that the duct burners are not operated unless the associated turbine units are in operation.

3. CO Emissions Limit Demonstration Period – The Demonstration Period is defined as the first 3 years immediately following the commencement of commercial operations (as defined in 40 CFR § 72.2).

   a. Permittee shall design the gas turbines to achieve a CO emission rate of 1.5 ppmvd @ 15% O_2 and 6.15 lb/hr over a 1-hour period without duct firing. Prior to construction, Permittee shall submit design specifications to EPA as proof that the gas turbines were designed to achieve such a rate, and a plan that sets forth the measures that will be taken to maintain the system and optimize its performance.

   b. During the Demonstration Period, Permittee shall operate the gas turbines according to the design specifications, within the design parameters, and consistent with the maintenance and performance optimization plan described above in Condition X.C.3.a. During the Demonstration Period, Permittee shall not discharge or cause the discharge of CO emissions from each CTG Unit (GEN1 and GEN2) into the atmosphere in excess of the following amounts over a 1-hour averaging period: 2.0 ppmvd CO @ 15% O_2 and (1) 10.10 lb/hr with duct firing or (2) 8.20 lb/hr without duct firing.

   c. Following the Demonstration Period, Permittee shall not discharge or cause the discharge of CO emissions from each CTG Unit (GEN1 and GEN2) into the atmosphere in excess of the following amounts over a 1-hour averaging period except as specified in Condition X.C.3.d:

      i. 1.5 ppmvd @ 15% O_2 without duct firing;
      ii. 2.0 ppmvd @ 15% O_2 with duct firing;
      iii. 6.15 lb/hr without duct firing; and
      iv. 10.10 lb/hr with duct firing.

   d. If, during the Demonstration Period, Permittee determines that the CO limits in Conditions X.C.3.i or X.C.3.iii are not feasible, Permittee shall submit an application to EPA prior to the end of the Demonstration Period requesting a revision of those limits. Such an application must contain data and information that demonstrates that the Facility was operated according to the design specifications and parameters, and the maintenance and performance optimization plan, identified above in Condition X.C.3.a, as well as a technical justification explaining why the lower limits are not feasible. If, after the applicable review process following such a submission (which will include an opportunity for public review and comment), it is determined through data and information gathered during the Demonstration Period that different CO limits are necessary, the limits in Condition X.C.3.i and X.C.3.iii will be revised accordingly. Provided that the application specified in this condition is postmarked prior to the end of the Demonstration Period, the emission limits in Condition X.C.3.b shall remain in effect until EPA evaluates the application and makes a final decision regarding the revision of the limits in Conditions X.C.3.i or X.C.3.iii.

D. Requirements during Gas Turbine (GEN1 and GEN2) Startup and Shutdown

1. Startup is defined as the period beginning with ignition and lasting until either the equipment complies with all operating permit limits for two consecutive 15-minute averaging periods or the maximum time allowed for the event after ignition, whichever occurs first; and the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations and demonstrate compliance with Condition X.C.

   a. A cold startup means a startup when the CTG has not been in operation during the preceding 48 hours.

   b. Warm and hot start-ups include all startups that are not a cold startup.

2. Shutdown is defined as the period beginning with the lowering of equipment from normal operating load and lasting until fuel flow is completely off and combustion has ceased.

3. The duration of startup and shutdown periods and emissions of NO_X and CO shall not exceed the following, for each CTG (GEN1 and GEN2) and associated HRSG unit, as verified by the CEMS:

	NO_x	CO	Duration
Cold Startup	96 lb/event	410 lb/event	110 minutes
Warm and Hot Startup	40 lb/event	329 lb/event	80 minutes
Shutdown	57 lb/event	337 lb/event	30 minutes

4. Permittee must operate the CEMS during startup and shutdown periods.

5. Permittee must record the time, date, and duration of each startup and shutdown event. The records must include calculations of NO_X and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

6. During startup, the SCR system, including ammonia injection, shall be operated as soon as the SCR reaches an operating temperature of 550 degrees Fahrenheit.

7. During startup or shutdown, emissions of NO_x from both CTGs (GEN1 and GEN2) combined shall not exceed 130 lb/hr, as verified by the CEMS.

8. During startup or shutdown, emissions of CO from both CTGs (GEN1 and GEN2) combined shall not exceed 790 lb/hr, as verified by the CEMS.

E. Auxiliary Combustion Equipment Emission Limits and Work Practices

1. At all times, including equipment startup and shutdown, Permittee shall not discharge or cause the discharge of emissions from each unit into the atmosphere in excess of the following, and shall otherwise comply with the following specifications:

Unit ID	NO_x	CO	PM / PM_{10} $PM_{2.5}$	GHG
Unit D1 110 MMBtu/hr (HHV) Boiler	• 9 ppmvd @ 3% O_2 • 3-hr average	• 50 ppmvd @ 3% O_2 • 3-hr average	• 0.8 lb/hr • PUC-quality pipeline natural gas	Annual boiler tune-ups
Unit D2 2,000 kW (2,683 hp) engine	• 6.4 g/kW-hr, (4.8 g/hp-hr), includes NMHC • 3-hr average	• 3.5 g/KW-hr, (2.6 g/hp-hr)	• 0.20 g/kW-hr, (0.15 g/hp-hr) • Use of ultra-low sulfur fuel, not to exceed 15 ppm fuel sulfur	Not applicable
Unit D3 182 hp firewater pump	• 4.0 g/KW-hr, (3.0 g/hp-hr), includes NMHC • 3-hr average		• Fuel supplier certification	Not applicable
Unit D4 40 MMBtu/hr (HHV) Heater	• 9 ppmvd @ 3% O_2 • 3-hr average	• 50 ppmvd @ 3% O_2 • 3-hr average	• 0.3 lb/hr • PUC-quality pipeline natural gas	Annual boiler tune-ups
Unit D5 130,000 gpm Cooling Tower	Not applicable	Not applicable	• 1.6 lb/hr (as total PM) • ≤ 0.0005% drift • ≤ 5,000 ppm total dissolved solids	Not applicable

Unit ID	NO_x	CO	PM / PM_{10} $PM_{2.5}$	GHG
CB SF_6 Circuit Breakers	Not applicable	Not applicable	Not applicable	• 9.56 tpy CO_2e • 12-month rolling total
MV Maintenance Vehicles	Not applicable	Not applicable	Conditions in X.E.9 including a Fugitive Dust Control Plan	Not applicable

2. 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 X.D.1. Annual hours of operation for Unit D1 shall not exceed 500 hours per 12-month rolling average.

3. Except during an emergency, Unit D2 shall be limited to operation of the engine for maintenance and testing purposes. Annual hours of operation for Unit D2, for maintenance and testing, shall not exceed 50 hours per 12-month rolling average.

4. Except during an emergency, Unit D3 shall be limited to operation of the engine for maintenance and testing purposes, including as required for fire safety testing. Annual hours of operation for Unit D3, for maintenance and testing, shall not exceed 50 hours per 12-month rolling average.

5. Units D2 and D3 shall not operate during startup of GEN1 or GEN2, except when Units D2 or D3 are required for emergency operations.

6. Unit D4 restrictions on usage shall be limited to annual hours of operation of not to exceed 1,000 hours per 12-month rolling average.

7. Unit D5 cooling tower emission limits shall not exceed the following:

    a. Drift rate shall not exceed 0.0005% with a maximum circulation rate of 130,000 gallons per minute (gpm). The maximum total dissolved solids (TDS) shall not exceed 5,000 ppm.

    b. The maximum hourly total PM emission rate from the cooling tower and the evaporative condenser combined shall not exceed 1.6 lb/hr.

8. Unit CB enclosed-pressure SF_6 circuit breakers:

a. Emissions shall not exceed an annual leakage rate of 0.5% by weight; and

b. Shall be equipped with a 10% by weight leak detection system.

9. For Unit MV, maintenance vehicles that travel on paved and unpaved roadways in the solar field associated with the Project, Permittee shall complete the following prior to the commencement of commercial operation (as defined in 40 CFR § 72.2):

   a. Pave the main access road into the plant site;

   b. Submit a Project Fugitive Dust Control Plan to EPA that includes fugitive road dust control measures for unpaved and paved roads, including, but not limited to:

      i. use of a durable non-toxic soil stabilizer applied throughout the solar field for dust control;
      ii. use of a durable non-toxic soil stabilizer to treat unpaved roads within the solar field used by wash trucks that spray and clean the mirrors;
      iii. inspection and maintenance procedures to ensure that the unpaved roads remain stabilized;
      iv. use of water trucks applying water on disturbed areas where soil stabilizers are not as effective;
      v. use of water in the mirror washing for incidental dust control; and
      vi. limiting vehicle speeds to no more than 10 miles per hour on unpaved roadways, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

10. Units D1 and D4 shall undergo annual tune-ups and meet the associated requirements of Condition X.I.9 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 startup):

    a. Inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 18 months).

    b. Inspect the flame pattern, and adjust the burner as necessary to optimize the flame pattern. The adjustment should 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.

    d. Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications.

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. Continuous Emissions Monitoring System (CEMS) for GEN1 and GEN2

1. At the earliest feasible opportunity after first fire of GEN1 and GEN2 and before GEN1 and GEN2 commence commercial operation (as defined in 40 CFR § 72.2), in accordance with the recommendations of the equipment manufacturer and the construction contractor:

   a. Permittee shall install, calibrate, and operate a CEMS each for GEN1 and GEN2 that measures stack gas NO_X, CO, and CO_2 concentrations in ppmv. The concentrations shall be corrected to 15% O_2 on a dry basis. No later than the end of the shakedown period as defined in Condition X.J. or upon commencing commercial operations, whichever comes first, Permittee shall also maintain, certify, and quality-assure a CEMS for each CTG that measures stack gas NO_X, CO, and CO_2 concentrations in ppmv, and shall conduct initial certification of the CEMS in accordance with Condition X.F.6. The concentrations shall be corrected to 15% O_2 on a dry basis.

   b. If Permittee chooses to install an O_2 CEMS, it shall be installed, calibrated and operated to measure O_2 concentrations in ppmv. No later than the end of the shakedown period as defined in Condition X.J. or upon commencing commercial operations, whichever comes first, Permittee shall also maintain, certify, and quality-assure the CEMS for each CTG that measures O_2 concentrations in ppmv, and shall conduct initial certification of the CEMS in accordance with Condition X.F.6. Permittee may not install an O_2 CEMS in lieu of the CO_2 CEMS in Condition X.F.1.a.

2. The NO_X, CO_2, and O_2 CEMS shall meet the applicable requirements of 40 CFR Part 75.

3. The CO CEMS shall meet the applicable requirements of 40 CFR Part 60 Appendix B, Performance Specification 4, and 40 CFR Part 60 Appendix F, Procedure 1, except the relative accuracy specified in section 13.2 of 40 CFR Part 60 Appendix B, Performance Specification 4 shall not exceed 20 percent.

4. Each CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute clock-hour period.

5. The CEMS shall be tested in accordance with Conditions X.F.2 and X.F.3.

6. The initial certification of the CEMS may either be conducted separately, as specified in 40 CFR § 60.334(b)(1), 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.

7. The CEMS shall meet the requirements of 40 CFR § 60.13. Data sampling, analyzing, and recording shall also be adequate to demonstrate compliance with emission limits during startup and shutdown.

8. Not less than 90 days prior to the date of initial startup of the Facility, the Permittee shall submit to the EPA a quality assurance project plan for the certification and operation of the CEMS. Such a plan shall conform to EPA requirements contained in 40 CFR Part 60 Appendix F for CO, 40 CFR Part 75 for NO_X and O_2 or CO_2, and 40 CFR Part 75 Appendix B for stack flow. The plan shall be updated and resubmitted upon request by EPA. The protocol shall specify how emissions during startups and shutdowns will be determined and calculated, including quantifying flow accurately if calculations are used.

9. The gas turbine CEMS shall be audited quarterly and tested annually in accordance with 40 CFR Part 60 Appendix F, Procedure 1. Permittee shall perform a full stack traverse during initial run of annual RATA testing of the CEMS, with testing points selected according to 40 CFR Part 60 Appendix A, Method 1.

10. Permittee shall submit a CEMS performance test protocol to the EPA no later than 30 days prior to the test date 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 EPA.

11. Permittee shall furnish the EPA a written report of the results of performance tests within 60 days of completion.

12. The stack gas volumetric flow rates shall be calculated in accordance with the fuel flowmeter requirements of 40 CFR Part 75 Appendix D in combination with the appropriate parts of EPA Method 19.

13. Prior to the date of initial startup of GEN1 and GEN2, Permittee shall install, and thereafter maintain and operate, continuous monitoring and recording systems to measure and record the following operational parameters:

    a. The ammonia injection rate of the ammonia injection system of the SCR system.

    b. Exhaust gas temperature at the inlet to the SCR reactor.

14. Permittee shall measure and record, for each Unit GEN1/DB1 and Unit GEN2/DB2, the actual heat input (Btu) on an hourly basis.

15. Permittee shall measure and record, for the entire facility, the following:

    a. Net energy output (MWh_{net} and kWh_{net}) on an hourly basis;

    b. Pounds of CO_2 per net energy output (lb CO_2/MWh_{net}) on an hourly basis;

    c. Net heat rate (Btu/kWh_{net}) on an hourly basis, based on total heat input for the facility;

    d. The 365-day rolling average emission rate of lb CO_2/MWh_{net} and Btu/kWh_{net}. The 365-day rolling average shall be based on the average hourly recordings.

G. Performance Tests

1. Stack Tests

   a. Within 60 days after achieving normal operation, but not later than 180 days after the initial startup of equipment, and, unless otherwise specified, annually thereafter (within 30 days of the initial performance test anniversary), Permittee shall conduct performance tests (as described in 40 CFR § 60.8) as follows:

      i. NO_X, CO, CO_2, PM, PM_{10}, and $PM_{2.5}$ emissions from each gas turbine (Units GEN1/DB1 and GEN2/DB2);
      ii. NO_X and CO emissions from the 110 MMBtu/hr boiler (D1) and the 40 MMBtu/hr heater (D4); PM, PM_{10}, and $PM_{2.5}$ emissions from the 110 MMBtu/hr boiler (D1) and the 40 MMBtu/hr heater (D4) shall be tested initially and at least every five years (within 30 days of the initial performance test anniversary);
      iii. NO_X, CO, PM, PM_{10}, and $PM_{2.5}$ emissions from the 2,000 kW (2,683 hp) internal combustion engine (D2), initial performance test and at least every five years beginning ten years after the initial performance test (within 30 days of the initial performance test anniversary);
      iv. NO_X, CO, PM, PM_{10}, and $PM_{2.5}$ emissions from the 182 hp firewater pump (D3), initial performance test and at least every five years beginning ten years after the initial performance test (within 30 days of the initial performance test anniversary); and
      v. PM, PM_{10}, and $PM_{2.5}$ emissions from the cooling tower (D5).

   b. Permittee shall submit a performance test protocol to 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 EPA.

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 EPA:

   i. EPA Methods 1-4 and 7E for NO_X emissions measured in ppmvd
   ii. EPA Methods 1-4, 7E, and 19 for NO_X emissions measured on a heat input basis
   iii. EPA Methods 1-4 and 10 for CO emissions
   iv. EPA Methods 1-4 and 3B for CO_2 emissions
   v. EPA Methods 5 and 202, or Methods 201A and 202, for PM, PM_{10}, and $PM_{2.5}$, in accordance with the test methods set forth in 40 CFR § 60.8, 40 CFR Part 60 Appendix A, and 40 CFR Part 51 Appendix M; in lieu of Method 202, Permittee may use EPA Conditional Test Methods for particulate matter CTM-039
   vi. Modified Method 306 or the Cooling Tower Institute's heated bead test method for PM emissions from the cooling tower, and
   vii. the provisions of 40 CFR § 60.8(f).

d. The initial performance test conducted after initial startup shall use the test procedures for a "high NO_2 emission site," as specified in San Diego Test Method 100, to measure NO_X emissions. The source shall be classified as either a "low" or "high" NO_2 emission site based on these test results. If the emission source is classified as a:

   i. "high NO_2 emission site," then each subsequent performance test shall use the test procedures for a "high NO_2 emission site," as specified in San Diego Test Method 100.
   ii. "low NO_2 emission site," then the test procedures for a "high NO_2 emission site," as specified in San Diego Test Method 100, shall be performed once every five years to verify the source's classification as a "low NO_2 emission site."

e. The performance test methods for NO_X emissions specified in Condition X.G.1.c.i and ii., may be modified as follows:

   i. Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load, and
   ii. Use the test data both to demonstrate compliance with the applicable NO_X emission limit and to provide the required reference method data for the RATA of the CEMS.

f. Upon written request and adequate justification from the Permittee, EPA may waive a specific annual test and/or allow for testing to be done at less than maximum operating capacity.

g. 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).

h. Permittee shall furnish the EPA a written report of the results of performance tests within 60 days of completion.

2. Cooling Tower Total Dissolved Solids Testing

a. Permittee shall perform weekly tests of the blow-down water quality using an EPA-approved method. The operator shall maintain a log that contains the date and result of each blow-down water quality test, the water circulation rate at the time of the test, and the resulting mass emission rate. This log shall be maintained onsite for a minimum of five years and shall be provided to EPA and District personnel upon request.

b. Permittee shall calculate PM, PM_{10}, and $PM_{2.5}$ emission rate using an EPA-approved calculation based on the TDS and water circulation rate.

c. The operator shall conduct all required cooling tower water quality tests in accordance with an EPA-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test, the operator shall provide a written test and emissions calculation protocol for EPA review and approval, with a copy to the District as specified in Condition XII below.

d. A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators, to ensure that the TDS limits are not exceeded, and to ensure compliance with recirculation rates. This procedure is to be kept onsite and made available to EPA and District personnel upon request. Permittee shall promptly report any deviations from this procedure.

3. Fuel Testing

a. Permittee shall take monthly samples of the natural gas combusted. 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 Special Conditions X.C and X.E for Units GEN1/DB1, GEN2/DB2, D1, and D4. As an alternative, Permittee may obtain laboratory analysis of sulfur content from the fuel supplier on a monthly basis, if Permittee can demonstrate that the fuel tested is representative of fuel delivered to the facility.

H. Monitoring for Auxiliary Equipment

1. Permittee shall install and maintain an operational non-resettable totalizing mass or volumetric flow meter in each fuel line for the 110 MMBtu/hr boiler (Unit D1) and the 40 MMBtu/hr heater (Unit D4).

2. Permittee shall install and maintain an operational non-resettable elapsed time meter for the 110 MMBtu /hr boiler (Unit D1), 2,000 kW emergency use engine (Unit D2), the 182 hp emergency-use firewater pump (Unit D3), and the 40 MMBtu/hr heater (Unit D4).

3. Permittee shall install and maintain a leak detection system on the circuit breakers that signals an alarm in the facility's control room in the event that any circuit breaker loses more than 10% of its dielectric fluid. The owner/operator shall promptly respond to any alarm, investigate the circuit breaker involved, and fix any leak-tightness problems that caused the alarm.

I. Recordkeeping and Reporting

1. Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the Facility, including, but not limited to, the following: all records or reports pertaining to adjustments and/or maintenance performed on any system or device at the Facility; all records relating to performance tests and monitoring of auxiliary combustion equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with the fuel sulfur content limit of Condition X.E; and all other information required by this permit recorded in a permanent form suitable for inspection.

2. Permittee shall maintain CEMS records that include the following: 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.

3. Permittee shall maintain records of all source tests and monitoring and compliance information required by this permit.

4. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an

applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:

a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;

b. 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;

c. A statement in the report of a negative declaration; that is, a statement when no excess emissions occurred or when the CEMS has not been inoperative, repaired, or adjusted;

d. Any failure to conduct any required source testing, monitoring, or other compliance activities; and

e. Any violation of limitations on operation, including but not limited to restrictions on hours of operation.

5. Excess emissions shall be defined as any period in which the Facility emissions exceed the maximum emission limits set forth in this permit.

6. 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 X.F.7.

7. Excess emissions indicated by the CEM system, source testing, or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

8. Permittee shall maintain the Fugitive Dust Control Plan on-site, which shall include all documentation related to demonstrating compliance with Condition X.E.9 for Unit MV, in a permanent form suitable for inspection.

9. Permittee shall conduct annual tune-ups as required by Condition X.E.10 for Units D1 and D4 and maintain onsite, and submit if requested by the Administrator, a biennial report containing the information in paragraphs (a) through (c) below:

a. The concentrations of CO in the effluent stream 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.

c. The type and amount of fuel used over the 12 months prior to the biennial tune-up of the boiler.

10. Permittee shall record the pounds of dielectric fluid added to the circuit breakers each month.

11. The Permittee shall maintain a copy of the current operation and maintenance plan for the STP, and shall keep a copy of all prior versions of the plan for a minimum of five years. The Permittee shall also keep records of the monitoring data for each of the plant performance measures and all maintenance activities; the Permittee shall maintain such records for a minimum of five years following the date they are created

12. Unless otherwise specified herein, all records required by this PSD Permit shall be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

J. Shakedown Periods

The combustion turbine emission limits and requirements in Conditions X.C, X.D, and X.E shall not apply during combustion shakedown periods. Shakedown is defined as the period beginning with initial startup 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 plant. The shakedown period shall not exceed 90 days. The requirements of Section III of this permit shall apply at all times.

XI. ACROYNMS AND ABBREVIATIONS

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
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2e	Carbon Dioxide Equivalent
CTG	Combustion Turbine Generator
CTM	Conditional Test Method
District	Antelope Valley Air Quality Management District
DLN	Dry Low NO_X
(d)scf	(dry) Standard Cubic Feet
EPA	Environmental Protection Agency
FDOC	Final Determination of Compliance
g	grams
GE	General Electric
GHG	Greenhouse Gas
gpm	Gallons Per Minute
gr	grains
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
hp	Horsepower
hr	Hour
IC	Internal Combustion
kPa	kilopascals
kW	Kilowatt
lb	Pounds
lbs	Pounds
MMBtu	Million British Thermal Units
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NNSR	Nonattainment New Source Review
NO_2	Nitrogen Dioxide
NO_X	Oxides of Nitrogen
NSPS	New Source Performance Standards
O_2	Oxygen
Ox-Cat	Oxidation Catalyst
PHPP	Palmdale Hybrid Power Project

PM	Total Particulate Matter
$PM_{2.5}$	Particulate Matter with aerodynamic diameter less than 2.5 micrometers
PM_{10}	Particulate Matter with aerodynamic diameter less than 10 micrometers
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
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
SO_2	Sulfur Dioxide
SO_X	Oxides of Sulfur
STG	Steam Turbine Generator
STP	Solar-thermal Plant
TDS	Total Dissolved Solids
tpy	Tons Per Year
yr	Year

XII. AGENCY NOTIFICATIONS

All correspondence as required by this Approval to Construct must be sent to:

A. Director, Air Division (Attn: AIR-5)
EPA Region IX
75 Hawthorne Street
San Francisco, CA 94105-3901

Email: R9.AEO@epa.gov
Fax: (415) 947-3579

With a copy to:

B. Air Pollution Control Officer
Antelope Valley Air Quality Management District
43301 Division Street, Suite 206
Lancaster, CA 93535
Fax: (661) 723-3450