



San Joaquin Valley

AIR POLLUTION CONTROL DISTRICT

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California Energy Commission
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Sacramento, CA 95814

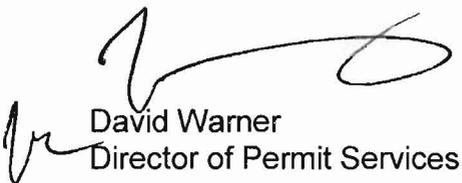
Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1080386 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Meyer:

The District mailed a letter, dated October 30, 2008, notifying you of the issuance of the Final Determination of Compliance for the Avenal Power Center LLC power plant. The letter was incorrectly titled "Notification of Preliminary Determination of Compliance (PDOC)". The title should have stated the letter was the "Notice of Final Determination of Compliance (FDOC)", consistent with the body of the letter. Please accept this letter as a correction to the previous notice letter dated October 30, 2008.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,



David Warner
Director of Permit Services

DW:df

Enclosures

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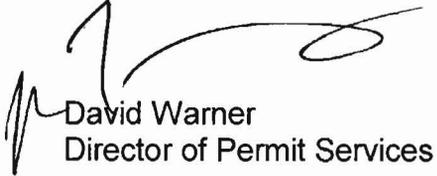
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Mr. Christopher Meyer
Page 2

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Sincerely,



David Warner
Director of Permit Services

DW:df

Enclosures

Fresno Bee

NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District has issued a Final Determination of Compliance (FDOC) to Avenal Power Center LLC for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032 in Avenal, CA.

All comments received following the District's preliminary decision on this project were considered. Changes were made to the DOC in direct response to comments received from the oversight agencies and other interested parties. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements.

The application review for project C-1080386 is available for public inspection at the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

FINAL DETERMINATION OF COMPLIANCE EVALUATION

**Avenal Power Center Project
California Energy Commission
Application for Certification Docket #: 08-AFC-01**

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Engineer: Derek Fukuda, Air Quality Engineer
Lead Engineer: Joven Refuerzo, Supervising Air Quality Engineer
Date: October 28, 2008

Project #: C-1080386
Application #'s: C-3953-10-0, C-3953-11-0, C-3953-12-0, C-3953-13-0, and
C-3953-14-0
Submitted: February 29, 2008

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I. PROPOSAL:

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 564 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

During the 30-day public notice period for this project several comments were received by the District from various community and regulatory entities. These comments and the Districts responses can be seen in Attachments J, K, and L. Based on these comments, the only significant change to the DOC was the lowering of the CO emission factor for the two natural gas-fired CTG's from 4.0 ppmvd @ 15% O₂ to 2.0 ppmvd @ 15% O₂.

The Avenal Energy Project is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

Additionally, the Avenal Energy Project is subject to Prevention of Significant Deterioration requirements by EPA Region IX.

II. APPLICABLE RULES:

- Rule 1080** Stack Monitoring (12/17/92)
- Rule 1081** Source Sampling (12/16/93)
- Rule 1100** Equipment Breakdown (12/17/92)
- Rule 2010** Permits Required (12/17/92)
- Rule 2201** New and Modified Stationary Source Review Rule (9/21/06)
- Rule 2520** Federally Mandated Operating Permits (6/21/01)
- Rule 2540** Acid Rain Program (11/13/97)
- Rule 2550** Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
- Rule 4001** New Source Performance Standards (4/14/99)
 - Subpart GG - Standards of Performance for Stationary Gas Turbines
 - Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
- Rule 4002** National Emissions Standards for Hazardous Air Pollutants (5/18/00)

- Rule 4101** Visible Emissions (2/17/05)
 - Rule 4102** Nuisance (12/17/92)
 - Rule 4201** Particulate Matter Concentration (12/17/92)
 - Rule 4202** Particulate Matter Emission Rate (12/17/92)
 - Rule 4301** Fuel Burning Equipment (12/17/92)
 - Rule 4305** Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
 - Rule 4306** Boilers, Steam Generators and Process Heaters – Phase 3 (3/17/05)
 - Rule 4351** Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
 - Rule 4701** Stationary Internal Combustion Engines – Phase 1 (8/21/03)
 - Rule 4702** Stationary Internal Combustion Engines – Phase 2 (1/18/07)
 - Rule 4703** Stationary Gas Turbines (8/17/06)
 - Rule 4801** Sulfur Compounds (12/17/92)
 - Rule 8011** General Requirements (8/19/04)
 - Rule 8021** Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
 - Rule 8031** Bulk Materials (8/19/04)
 - Rule 8041** Carryout and Trackout (8/19/04)
 - Rule 8051** Open Areas (8/19/04)
 - Rule 8061** Paved and Unpaved Roads (8/19/04)
 - Rule 8071** Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
 - Rule 8081** Agricultural Sources (9/16/04)
- California Environmental Quality Act (CEQA)**
California Code of Regulations (CCR), Section 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment)
California Health & Safety Code (CH&S), Sections 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment) 41700 (Health Risk Analysis), 42301.6 (School Notice), 44300 (Air Toxic “Hot Spots”), and 93115 (Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines)

III. PROJECT LOCATION:

The proposed equipment will be located within NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor’s Parcel Number 36-170-032 (See Attachment B). The closest population center is the residential district of Avenal approximately 6 miles to the southwest. The City of Huron is located approximately 8 miles to the north, and the City of Coalinga is located approximately 16 miles to the west.

The site is located northeast of the city of Avenal, in Kings County. The proposed location is not within 1,000’ of a K-12 school.

IV. PROCESS DESCRIPTION:

Combined-Cycle Combustion Turbine Generators

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_x combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_x (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

- NO_x: 2.0 ppmvd @ 15% O₂
- VOC: 2.0 ppmvd @ 15% O₂
- CO: 2.0 ppmvd @ 15% O₂
- SO_x: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf)
- PM₁₀: 0.0107 lb/MMBtu

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_x, CO, and O₂ concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce steam. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP

condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_x in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_x to nitrogen and water, resulting in a reduced concentration of NO_x in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_x burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump

Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator

One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

V. EQUIPMENT LISTING:

- C-3953-10-0:** 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_x COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11
- C-3953-11-0:** 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_x COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10
- C-3953-12-0:** 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER
- C-3953-13-0:** 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP
- C-3953-14-0:** 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

i. C-3953-10-0 and C-3953-11-0 (Turbines)

Each CTG will be equipped with a Dry Low NO_x combustor and will exhaust into a Selective Catalytic Reduction [SCR] system with ammonia injection, and a CO catalyst. The use of Dry Low NO_x combustors and a SCR system with ammonia injection can achieve a NO_x emission rate of 2.0 ppmvd @ 15% O₂. CO emissions of 2.0 ppmvd @

15% O₂ have been demonstrated with the use of an oxidation catalyst ⁽¹⁾. And the use of DLN combustors and good combustion practices can achieve VOC emissions of 2.0 ppmvd @ 15% O₂.

Emissions from natural gas-fired turbines include NO_x, CO, VOC, PM₁₀, and SO_x.

NO_x is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_x emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO₂ molecule. There are two mechanisms by which NO_x is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x and prompt NO_x), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x).

Thermal NO_x is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_x, a form of thermal NO_x, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_x. Prompt NO_x is formed in both fuel-rich flame zones and dry low NO_x (DLN) combustion zones. The contribution of prompt NO_x to overall NO_x emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal NO_x emissions in DLN combustors. For this reason prompt NO_x becomes an important consideration for DLN combustor designs, and establishes a minimum NO_x level attainable in lean mixtures.

Fuel NO_x is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N₂ in some natural gas, does not contribute significantly to fuel NO_x formation. With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_x, fuel NO_x is not currently a major contributor to overall NO_x emissions from stationary gas turbines firing natural gas.

The level of NO_x formation in a gas turbine, and hence the NO_x emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_x generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

The design of the combustor is the most important factor influencing the formation of NO_x. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_x formation. Thermal NO_x formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_x formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_x production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_x formation. Premixing air and fuel at a lean ratio approaching the lean

¹ Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.

flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_x formation during combustion. This is known as dry low NO_x (DLN) combustion.

Selective Catalytic Reduction systems selectively reduce NO_x emissions by injecting ammonia (NH₃) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH₃, and O₂ react on the surface of the catalyst to form molecular nitrogen (N₂) and H₂O. SCR is capable of over 90 percent NO_x reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_x and NH₃ to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% O₂.

Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit NO_x formation can result in increased CO emissions.

Post-combustion CO controls, such as oxidizing catalysts can also be used to reduce CO emissions. An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO₂).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The inlet air filter will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

ii. C-3953-12-0 (Boiler)

Emissions from natural gas-fired boilers include NO_x, CO, VOC, PM₁₀, and SO_x.

NO_x is the major pollutant of concern when burning natural gas. NO_x formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_x) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_x). Due to the low fuel nitrogen content of natural gas, nearly all NO_x emissions are thermal NO_x. Formation of

thermal NO_x is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

The Cleaver Brooks boiler will control the formation of thermal NO_x with an Cleaver Brooks ultra low NO_x burner. Cleaver Brooks burners reduce NO_x by pre-mixing gaseous fuel and combustion air in a region near the burner exit, at a stoichiometry that minimizes Prompt NO_x. This also eliminates the traditional NO_x versus CO tradeoff.

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The diesel-fired emergency IC engine (fire pump) will be equipped with a turbocharger, an intercooler/aftercooler, and will be fired on very low (0.0015%) sulfur diesel.

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.²

The turbocharger reduces the NO_x emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_x. NO_x emissions are reduced by approximately 15% with this control technology.

The use of low sulfur (0.0015% by weight sulfur maximum) diesel fuel reduces SO_x emissions by approximately 99% from standard diesel fuel.

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The natural gas-fired emergency IC engine (generator) will be equipped with an intercooler/aftercooler, lean burn technology, and will be fired on PUC-Regulated natural gas.

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.³

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_x. NO_x emissions are reduced by approximately 15% with this control technology.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved

² From "Non-catalytic NO_x Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

³ From "Non-catalytic NO_x Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_x formation.

VII. GENERAL CALCULATIONS:

i. C-3953-10-0 and C-3953-11-0 (Turbines)

- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- Maximum daily emissions for each CTG for VOC, PM₁₀ and SO_x during the commissioning period are estimated assuming twenty-four (24) hours operating while firing at full load.
- The commissioning period will not exceed 408 hours per CTG and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.
- Maximum daily emissions for each CTG for NO_x, CO, and VOC are estimated assuming six (6) hours operating in startup and shutdown mode and eighteen (18) hours operating while firing at full load with operation of the duct burner.
- Maximum daily emissions for each CTG for PM₁₀, SO_x, and NH₃ are estimated assuming twenty-four (24) hours operating while firing at full load with the operation of the duct burner.
- Maximum annual emissions for each CTG for NO_x and VOC are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner.
- Maximum annual emissions for each CTG for CO are estimated assuming the CTG is operated according to a weekend shutdown and weekday hot start scenario. The weekend shutdown and weekday hot start scenario results in CTG operation of 624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner.
- Maximum annual emissions for each CTG for PM₁₀, SO_x, and NH₃ are estimated assuming the CTG is operated according to a baseload scenario. The baseload scenario results in CTG operation of 800 hours operating while firing at full load with the duct burner and 7,960 hours operating while firing at full load without the duct burner.

ii. C-3953-12-0 (Boiler)

- External O₂ stack gas concentration is 3%.
- Natural gas F factor is 8,710 dscf/MMBtu (Ref. 40 CFR Part 60, Appendix A, Method 19).
- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- The applicant is proposing a maximum natural gas usage rate of 37.4 MMBtu/hr.
- Maximum SO_x emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

$$(1 \text{ gr-S}/100 \text{ dscf} \times 1 \text{ lb-S}/7000 \text{ gr} \times 64 \text{ lb SO}_x/32 \text{ lb-S} \times 1 \text{ scf}/1013 \text{ Btu} \times 10^6 \text{ Btu/MMBtu}) \\ = 0.00282 \text{ lb/MMBtu}$$

- Maximum daily and annual emissions for all pollutants are estimated assuming twelve (12) hours per day and 1,248 hours per year operating at full load.⁴
- Operating schedule of 12 hr/day and 1,248 hrs/year.

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

- Diesel F factor (adjusted to 60 °F) is 9,051 dscf/MMBtu.
- Density of diesel is 7.1 lb/gal.
- Higher heating value of diesel is 137,000 Btu/scf.
- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

- EPA F-factor (adjusted to 60 °F) is 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- Fuel heating value 1,013 Btu/dscf (per applicant)
- Maximum daily SO_x emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

$$(1 \text{ gr-S}/100 \text{ dscf} \times 1 \text{ lb-S}/7000 \text{ gr} \times 64 \text{ lb SO}_x/32 \text{ lb-S} \times 1 \text{ scf}/1013 \text{ Btu} \times 10^6 \text{ Btu/MMBtu}) \\ = 0.00282 \text{ lb/MMBtu}$$

- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

⁴ Applicant has indicated that the unit will be used a maximum of 12 hours on a startup day.

B. Emission Factors

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

Commissioning Period Emissions					
	NO_x	CO	VOC	PM₁₀	SO_x
Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A ⁽⁵⁾	N/A ⁽⁵⁾

The maximum air contaminant mass emission rates (lb/hr) with and without duct burner firing, concentrations (ppmvd @ 15% O₂), and startup and shutdown emissions rates (lb/hr) provided by the applicant (see Attachment D for applicant proposed emissions) for the proposed CTGs are summarized below.

The emission rates from the turbines and duct burners are calculated below:

Maximum Emission Rate Without Duct Burner Firing:

The worst-case NO_x, PM₁₀, CO, VOC, and NH₃ mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 32 °F. The worst-case SO_x mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG without the duct burner firing:

$$\text{Emission Rate (lb/hr)} = \text{CTG Max Heat Input (MMBtu/hr)} \times \text{Emission Factor (lb/MMBtu)}$$

$$\begin{aligned} \text{NO}_x \text{ Emission Rate (lb/hr)} &= (1,856.3 \text{ MMBtu/hr}) \times (0.0073 \text{ lb-NO}_x\text{/MMBtu}) \\ &= \mathbf{13.55 \text{ lb-NO}_x\text{/hr}} \end{aligned}$$

$$\begin{aligned} \text{CO Emission Rate (lb/hr)} &= (1,856.3 \text{ MMBtu/hr}) \times (0.0045 \text{ lb-CO/MMBtu}) \\ &= \mathbf{8.35 \text{ lb-CO/hr}} \end{aligned}$$

$$\begin{aligned} \text{VOC Emission Rate (lb/hr)} &= (1,856.3 \text{ MMBtu/hr}) \times (0.0018 \text{ lb-VOC/MMBtu}) \\ &= \mathbf{3.34 \text{ lb-VOC/hr}} \end{aligned}$$

$$\begin{aligned} \text{PM}_{10} \text{ Emission Rate (lb/hr)} &= (1,856.3 \text{ MMBtu/hr}) \times (0.0048 \text{ lb-PM}_{10}\text{/MMBtu}) \\ &= \mathbf{8.91 \text{ lb-PM}_{10}\text{/hr}} \end{aligned}$$

⁵ PM₁₀ and SO_x emissions during commissioning period are equal to the maximum hourly emissions during baseload facility operation.

$$\text{SO}_x \text{ Emission Rate (lb/hr)} = (1,856.3 \text{ MMBtu/hr}) \times (0.00282 \text{ lb-SO}_x\text{/MMBtu})$$

$$= \mathbf{5.23 \text{ lb-SO}_x\text{/hr}}$$

$$\text{NH}_3 \text{ Emission Rate (lb/hr)} = \text{ppm} \times \text{MW} \times (2.64 \times 10^{-9}) \times \text{ff} \times \text{HV} \times \text{FL} \times [20.9 / (20.9 - \text{O}_2\%)]$$

Where:

- ppm is the emission concentration in ppmvd @ 15% O₂ (10 ppmv)
- MW is the molecular weight of the pollutant: (MW_{NH₃} = 17 lb/lb-mol)
- 2.64 x 10⁻⁹ is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
- ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
- HV is the heating value of natural gas: (1,013 Btu/scf)
- FL is the amount of natural gas each turbine can burn in any given hour: (CTG w/o duct burner 1.832 MMscf/hour, as calculated below)
- (1,856.3 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 1.832 MMscf/hr
- O₂ is the stack oxygen content to which the emission concentrations are corrected: (15%)

$$\text{NH}_3 \text{ Emission Rate (lb/hr)} = 10 \times 17 \times (2.64 \times 10^{-9}) \text{ (lb-mol/MMscf)} \times 8,578 \text{ (scf/MMBtu)} \times$$

$$1,013 \text{ (Btu/scf)} \times 1.832 \text{ (MMscf/hr)} \times [20.9 / (20.9 - 15.0)]$$

$$= \mathbf{25.31 \text{ lb-NH}_3\text{/hr}}$$

Maximum Emission Rates and Concentrations Without Duct Burner Firing						
(@ 100% Load & 32 °F)						
	NO_x	CO	VOC	PM₁₀	SO_x	NH₃
Mass Emission Rates (per turbine, lb/hr)	13.55	8.35	3.34	8.91	5.23	25.31
ppmvd @ 15% O₂ limits	2.0	2.0	1.4	--	--	10.0
lb/MMBtu*	0.0073	0.0045	0.0018	0.0048	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Maximum Emission Rate With Duct Burner Firing:

The worst-case NO_x, SO_x, PM₁₀, CO, VOC, and NH₃ mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 101 °F. The worst-case SO_x mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG with the duct burner firing:

$$\text{Emission Rate (lb/hr)} = [\text{CTG Max Heat Input} + \text{Duct Burner Max Heat Input}] \text{ (MMBtu/hr)}$$

$$\times \text{Emission Factor (lb/MMBtu)}$$

$$\text{NO}_x \text{ Emission Rate (lb/hr)} = (2,356.5 \text{ MMBtu/hr}) \times (0.0073 \text{ lb-NO}_x\text{/MMBtu})$$

$$= \mathbf{17.20 \text{ lb-NO}_x\text{/hr}}$$

$$\text{CO Emission Rate (lb/hr)} = (2,356.5 \text{ MMBtu/hr}) \times (0.0045 \text{ lb-CO/MMBtu})$$

$$= \mathbf{10.60 \text{ lb-CO/hr}}$$

$$\text{VOC Emission Rate (lb/hr)} = (2,356.5 \text{ MMBtu/hr}) \times (0.0025 \text{ lb-VOC/MMBtu})$$

$$= \mathbf{5.89 \text{ lb-VOC/hr}}$$

$$\text{PM}_{10} \text{ Emission Rate (lb/hr)} = (2,356.5 \text{ MMBtu/hr}) \times (0.0050 \text{ lb-PM}_{10}\text{/MMBtu})$$

$$= \mathbf{11.78 \text{ lb-PM}_{10}\text{/hr}}$$

$$\text{SO}_x \text{ Emission Rate (lb/hr)} = (2,356.5 \text{ MMBtu/hr}) \times (0.00282 \text{ lb-SO}_x\text{/MMBtu})$$

$$= \mathbf{6.65 \text{ lb-SO}_x\text{/hr}}$$

$$\text{NH}_3 \text{ Emission Rate (lb/hr)} = \text{ppm} \times \text{MW} \times (2.64 \times 10^{-9}) \times \text{ff} \times \text{HV} \times \text{FL} \times [20.9 / (20.9 - \text{O}_2\%)]$$

Where:

ppm is the emission concentration in ppmvd @ 15% O₂ (10 ppmv)

MW is the molecular weight of the pollutant: (MW_{NH₃} = 17 lb/lb-mol)

2.64 x 10⁻⁹ is one over the molar specific volume (lb-mol/MMscf, at 60 °F)

ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)

HV is the heating value of natural gas: (1,013 Btu/scf)

FL is the amount of natural gas each turbine can burn in any given hour: (CTG w duct burner 2.326 MMscf/hour, as calculated below)

$$(2,356.5 \text{ MMBtu/hr}) \div (1,013 \text{ MMBtu/MMscf}) = 2.326 \text{ MMscf/hr}$$

O₂ is the stack oxygen content to which the emission concentrations are corrected: (15%)

$$\text{NH}_3 \text{ Emission Rate (lb/hr)} = 10 \times 17 \times (2.64 \times 10^{-9}) (\text{lb-mol/MMscf}) \times 8,578 (\text{scf/MMBtu}) \times$$

$$1,013 (\text{Btu/scf}) \times 2.326 (\text{MMscf/hr}) \times [20.9 / (20.9 - 15.0)]$$

$$= \mathbf{32.13 \text{ lb-NH}_3\text{/hr}}$$

Maximum Emission Rates and Concentrations With Duct Burner Firing (@ 100% Load & 101 °F)						
	NO_x	CO	VOC	PM₁₀	SO_x	NH₃
Mass Emission Rates (per turbine, lb/hr)	17.20	10.60	5.89	11.78	6.65	32.13
ppmvd @ 15% O ₂ limits	2.0	2.0	2.0	--	--	10.0
lb/MMBtu*	0.0074	0.0045	0.0025	0.0050	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Startup and Shutdown Emissions					
	NO _x	CO	VOC	PM ₁₀	SO _x
Maximum Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A ⁽⁶⁾	N/A ⁽⁶⁾
Average Mass Emission Rate (per turbine, lb/hr)	80	900	16	N/A ⁽⁶⁾	N/A ⁽⁶⁾

ii. C-3953-12-0 (Boiler)

For the new boiler, the emissions factors for NO_x, CO, VOC, and PM₁₀ are provided by the applicant. The SO_x emission factor is calculated as shown below.

Boiler Emission Factors*		
Pollutant	ppmv @ 3%O ₂	lb/MMBtu
NO _x	9.0	0.011
CO	50.0	0.037
VOC	10.0	0.0043
PM ₁₀	--	0.005
SO _x **	--	0.00282

*Note: lb/MMBtu equivalent of ppmv values @ 3% O₂ as provided by the Applicant
 ** SO_x emission factor based on the maximum proposed sulfur content of 1 gr/100 dscf.

$$(1 \text{ gr-S}/100 \text{ dscf} \times 1 \text{ lb-S}/7000 \text{ gr} \times 64 \text{ lb SO}_x/32 \text{ lb-S} \times 1 \text{ scf}/1013 \text{ Btu} \times 10^6 \text{ Btu/MMBtu}) = 0.00282 \text{ lb/MMBtu}$$

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

For the new emergency diesel-fired IC engine powering a fire water pump, the emissions factors for NO_x, CO, VOC, and PM₁₀ are provided by the applicant and are guaranteed by the engine manufacturer. The SO_x emission factor is calculated using the sulfur content in the diesel fuel (0.0015% sulfur).

⁶ PM₁₀ and SO_x emissions during startups and shutdowns are lower than maximum hourly emissions during baseload facility operation.

Diesel-fired IC Engine Emission Factors		
	g/hp · hr	Source
NO _x	3.4	Engine Manufacturer
CO	0.447	Engine Manufacturer
VOC	0.38	Engine Manufacturer
PM ₁₀	0.059	Engine Manufacturer
*SO _x	0.005	Mass Balance Equation Below

$$*0.0015\% \times \frac{7.1 \text{ lb} \cdot \text{fuel}}{\text{gallon}} \times \frac{2 \text{ lb} \cdot \text{SO}_2}{1 \text{ lb} \cdot \text{S}} \times \frac{1 \text{ gal}}{137,000 \text{ Btu}} \times \frac{1 \text{ hp input}}{0.35 \text{ hp out}} \times \frac{2,542.5 \text{ Btu}}{\text{hp} \cdot \text{hr}} \times \frac{453.6 \text{ g}}{\text{lb}} = 0.005 \frac{\text{g SO}_x}{\text{hp} \cdot \text{hr}}$$

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

For the new emergency natural gas-fired IC engine powering an electrical generator, the emissions factors for NO_x, CO, VOC, and PM₁₀ are provided by the applicant and are guaranteed by the engine manufacturer. The SO_x emission factor is calculated using the fuel sulfur content from District Policy APR 1720.

Natural Gas-fired IC Engine Emission Factors		
	g/hp · hr	Source
NO _x	1.0	Engine Manufacturer
CO	0.6	Engine Manufacturer
VOC	0.33	Engine Manufacturer
PM ₁₀	0.034	Engine Manufacturer
**SO _x	0.0094	Mass Balance Equation Below

**SO_x is calculated as follows:

$$0.00285 \frac{\text{lb} - \text{SO}_x}{\text{MMBtu}} \times \frac{1 \text{ MMBtu}}{1,000,000 \text{ Btu}} \times \frac{2,542.5 \text{ Btu}}{\text{bhp} - \text{hr}} \times \frac{1 \text{ bhp input}}{0.35 \text{ bhp out}} \times \frac{453.6 \text{ g}}{\text{lb}} = 0.0094 \frac{\text{g} - \text{SO}_x}{\text{bhp} - \text{hr}}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Since this is a brand new facility, the pre-project potential to emit (PE1) for all the emissions units associated with this project is equal to zero.

2. Post Project Potential to Emit (PE2):

i. C-3953-10-0 and C-3953-11-0 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_x, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NO_x emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)].

Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO _x	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM ₁₀	N/A ⁽⁷⁾	11.78	8.91	8.91	23.56
SO _x	N/A ⁽⁷⁾	6.65	5.23	5.23	13.30
NH ₃	N/A	32.13	25.31	25.31	64.26

b. Maximum Daily PE

Maximum daily emissions for NO_x, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM₁₀, SO_x, and NH₃ are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM₁₀, SO_x, and NH₃ occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

⁷ PM₁₀ and SO_x emissions during startups and shutdowns are lower than maximum hourly emissions.

Maximum Daily Potential to Emit (w/ Startup and Shutdown)				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO _x	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM ₁₀	N/A ⁽⁸⁾	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO _x	N/A ⁽⁸⁾	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH ₃	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

c. Maximum Annual PE

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_x emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

$$\begin{aligned} \text{SO}_x \text{ EF} &= (0.36 \text{ gr-S}/100 \text{ dscf}) \times (1 \text{ lb-S}/7000 \text{ gr}) \times (64 \text{ lb SO}_x/32 \text{ lb-S}) \times (1 \text{ scf}/1013 \text{ Btu}) \\ &\quad \times (10^6 \text{ Btu/MMBtu}) \\ &= \mathbf{0.001 \text{ lb-SO}_x/\text{MMBtu}} \end{aligned}$$

CTG w/o Duct Burner Firing:

$$\begin{aligned} \text{SO}_x \text{ Emission Rate (lb/hr)} &= (1,856.3 \text{ MMBtu/hr}) \times (0.001 \text{ lb-SO}_x/\text{MMBtu}) \\ &= \mathbf{1.86 \text{ lb-SO}_x/\text{hr}} \end{aligned}$$

CTG w/ Duct Burner Firing:

$$\begin{aligned} \text{SO}_x \text{ Emission Rate (lb/hr)} &= (2,356.5 \text{ MMBtu/hr}) \times (0.001 \text{ lb-SO}_x/\text{MMBtu}) \\ &= \mathbf{2.36 \text{ lb-SO}_x/\text{hr}} \end{aligned}$$

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

Scenario 1) Weekend and Weekday Hot Start:

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM₁₀, SO_x, and NH₃ are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO _x	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	143,951 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	34,489 lb/year
PM ₁₀	N/A ⁽⁸⁾	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO _x	N/A ⁽⁸⁾	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH ₃	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 2) Weekend Shutdown and Weekday Hot Start:

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM₁₀, SO_x, and NH₃ are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit				
Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO _x	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	601,810 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM ₁₀	N/A ⁽⁸⁾	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO _x	N/A ⁽⁸⁾	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH ₃	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit				
Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO _x	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM ₁₀	N/A ⁽⁸⁾	11.27 lb/hr	9.00 lb/hr	80,656 lb/year
SO _x	N/A ⁽⁸⁾	2.36 lb/hr	1.86 lb/hr	16,694 lb/year
NH ₃	N/A	32.13 lb/hr	25.31 lb/hr	219,972 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO _x	143,951 lb/year	Scenario 1
CO	601,810 lb/year	Scenario 2
VOC	34,489 lb/year	Scenario 2
PM ₁₀	80,656 lb/year	Scenario 3
SO _x	16,694 lb/year	Scenario 3
NH ₃	219,972 lb/year	Scenario 3

d. Maximum Quarterly PE

Maximum quarterly emissions for each unit will be determined by dividing the maximum annual emissions into 4 quarters:

Maximum Quarterly Potential to Emit						
	NO _x	CO	VOC	PM ₁₀	SO _x	NH ₃
1 st Quarter	35,987.75	150,452.5	8,622.25	20,164	4,173.5	54,993
2 nd Quarter	35,987.75	150,452.5	8,622.25	20,164	4,173.5	54,993
3 rd Quarter	35,987.75	150,452.5	8,622.25	20,164	4,173.5	54,993
4 th Quarter	35,987.75	150,452.5	8,622.25	20,164	4,173.5	54,993

ii. C-3953-12-0 (Boiler)

The potential to emit for the boiler is calculated as follows, and summarized in the table below.

$$\begin{aligned}
 PE_{NO_x} &= (0.011 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) \\
 &= \mathbf{0.41 \text{ lb NO}_x/\text{hr}} \\
 &= (0.011 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (12 \text{ hr/day}) \\
 &= \mathbf{4.9 \text{ lb NO}_x/\text{day}} \\
 &= (0.011 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (1,248 \text{ hr/year}) \\
 &= \mathbf{513 \text{ lb NO}_x/\text{year}} \\
 &= (513 \text{ lb NO}_x/\text{year}) \div (4 \text{ qtr/year}) \\
 &= \mathbf{128 \text{ lb NO}_x/\text{qtr}}
 \end{aligned}$$

$$\begin{aligned} PE_{CO} &= (0.037 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) \\ &= \mathbf{1.38 \text{ lb CO/hr}} \\ &= (0.037 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (12 \text{ hr/day}) \\ &= \mathbf{16.6 \text{ lb CO/day}} \\ &= (0.037 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (1,248 \text{ hr/year}) \\ &= \mathbf{1,727 \text{ lb CO/year}} \\ &= (1,727 \text{ lb CO/year}) * (4 \text{ qtr/year}) \\ &= \mathbf{432 \text{ lb CO/qtr}} \end{aligned}$$

$$\begin{aligned} PE_{VOC} &= (0.0043 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) \\ &= \mathbf{0.16 \text{ lb VOC/hr}} \\ &= (0.0043 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (12 \text{ hr/day}) \\ &= \mathbf{1.9 \text{ lb VOC/day}} \\ &= (0.0043 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (1,248 \text{ hr/year}) \\ &= \mathbf{201 \text{ lb VOC/year}} \\ &= (201 \text{ lb/year}) * (4 \text{ qtr/year}) \\ &= \mathbf{50 \text{ lb VOC/qtr}} \end{aligned}$$

$$\begin{aligned} PE_{PM10} &= (0.005 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) \\ &= \mathbf{0.19 \text{ lb PM}_{10}\text{/hr}} \\ &= (0.005 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (12 \text{ hr/day}) \\ &= \mathbf{2.2 \text{ lb PM}_{10}\text{/day}} \\ &= (0.005 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (1,248 \text{ hr/year}) \\ &= \mathbf{233 \text{ lb PM}_{10}\text{/year}} \\ &= (233 \text{ lb/year}) * (4 \text{ qtr/year}) \\ &= \mathbf{58 \text{ lb PM}_{10}\text{/qtr}} \end{aligned}$$

$$\begin{aligned} PE_{SOx} &= (0.00282 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) \\ &= \mathbf{0.11 \text{ lb SO}_x\text{/hr}} \\ &= (0.00282 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (12 \text{ hr/day}) \\ &= \mathbf{1.3 \text{ lb SO}_x\text{/day}} \\ &= (0.00282 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (1,248 \text{ hr/year}) \\ &= \mathbf{132 \text{ lb SO}_x\text{/year}} \end{aligned}$$

$$= (132 \text{ lb/year}) * (4 \text{ qtr/year})$$

$$= \mathbf{33 \text{ lb SO}_x/\text{qtr}}$$

Post Project Potential to Emit (PE2) (C-3953-12-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO _x	0.41	4.9	128	513
CO	1.38	16.6	432	1,727
VOC	0.16	1.9	50	201
PM ₁₀	0.19	2.2	58	233
SO _x	0.11	1.3	33	132

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

$$PE_{NO_x} = (3.4 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb})$$

$$= \mathbf{2.16 \text{ lb NO}_x/\text{hr}}$$

$$= (3.4 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day})$$

$$= \mathbf{51.8 \text{ lb NO}_x/\text{day}}$$

$$= (3.4 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr})$$

$$= \mathbf{27 \text{ lb NO}_x/\text{qtr}}$$

$$= (3.4 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year})$$

$$= \mathbf{108 \text{ lb NO}_x/\text{year}}$$

$$PE_{CO} = (0.447 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb})$$

$$= \mathbf{0.28 \text{ lb CO/hr}}$$

$$= (0.447 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day})$$

$$= \mathbf{6.8 \text{ lb CO/day}}$$

$$= (0.447 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr})$$

$$= \mathbf{4 \text{ lb CO/qtr}}$$

$$= (0.447 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year})$$

$$= \mathbf{14 \text{ lb CO/year}}$$

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$$\begin{aligned}
 PE_{VOC} &= (0.38 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) \\
 &= \mathbf{0.24 \text{ lb VOC/hr}} \\
 &= (0.38 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\
 &= \mathbf{5.8 \text{ lb VOC/day}} \\
 &= (0.38 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\
 &= \mathbf{3 \text{ lb VOC/qtr}} \\
 &= (0.38 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\
 &= \mathbf{12 \text{ lb VOC/year}}
 \end{aligned}$$

$$\begin{aligned}
 PE_{PM_{10}} &= (0.059 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) \\
 &= \mathbf{0.04 \text{ lb PM}_{10}\text{/hr}} \\
 &= (0.059 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\
 &= \mathbf{0.9 \text{ lb PM}_{10}\text{/day}} \\
 &= (0.059 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\
 &= \mathbf{0.5 \text{ lb PM}_{10}\text{/qtr}} \\
 &= (0.059 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\
 &= \mathbf{1.9 \text{ lb PM}_{10}\text{/year}}
 \end{aligned}$$

$$\begin{aligned}
 PE_{SO_x} &= (0.005 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) \\
 &= \mathbf{0.00 \text{ lb SO}_x\text{/hr}} \\
 &= (0.005 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\
 &= \mathbf{0.1 \text{ lb SO}_x\text{/day}} \\
 &= (0.005 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\
 &= \mathbf{0 \text{ lb SO}_x\text{/qtr}} \\
 &= (0.005 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\
 &= \mathbf{0 \text{ lb SO}_x\text{/year}}
 \end{aligned}$$

Post Project Potential to Emit (PE2) (C-3953-13-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO _x	2.16	51.8	27	108
CO	0.28	6.8	4	14
VOC	0.24	5.8	3	12
PM ₁₀	0.04	0.9	0.5	2
SO _x	0.00	0.1	0	0

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

$$\begin{aligned} PE_{NO_x} &= (1.0 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) \\ &= \mathbf{1.90 \text{ lb NO}_x/\text{hr}} \\ &= (1.0 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\ &= \mathbf{45.5 \text{ lb NO}_x/\text{day}} \\ &= (1.0 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\ &= \mathbf{24 \text{ lb NO}_x/\text{qtr}} \\ &= (1.0 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\ &= \mathbf{95 \text{ lb NO}_x/\text{year}} \end{aligned}$$

$$\begin{aligned} PE_{CO} &= (0.6 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) \\ &= \mathbf{1.14 \text{ lb CO/hr}} \\ &= (0.6 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\ &= \mathbf{27.3 \text{ lb CO/day}} \\ &= (0.6 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\ &= \mathbf{14 \text{ lb CO/qtr}} \\ &= (0.6 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\ &= \mathbf{57 \text{ lb CO/year}} \end{aligned}$$

$$\begin{aligned} PE_{VOC} &= (0.33 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) \\ &= \mathbf{0.63 \text{ lb VOC/hr}} \\ &= (0.33 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\ &= \mathbf{15.0 \text{ lb VOC/day}} \\ &= (0.33 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\ &= \mathbf{8 \text{ lb VOC/qtr}} \\ &= (0.33 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\ &= \mathbf{31 \text{ lb VOC/year}} \end{aligned}$$

$$\begin{aligned}
 PE_{PM_{10}} &= (0.034 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) \\
 &= \mathbf{0.06 \text{ lb PM}_{10}/\text{hr}} \\
 &= (0.034 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\
 &= \mathbf{1.5 \text{ lb PM}_{10}/\text{day}} \\
 &= (0.034 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\
 &= \mathbf{1 \text{ lb PM}_{10}/\text{qtr}} \\
 &= (0.034 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\
 &= \mathbf{3 \text{ lb PM}_{10}/\text{year}}
 \end{aligned}$$

$$\begin{aligned}
 PE_{SO_x} &= (0.0094 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) \\
 &= \mathbf{0.02 \text{ lb SO}_x/\text{hr}} \\
 &= (0.0094 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\
 &= \mathbf{0.4 \text{ lb SO}_x/\text{day}} \\
 &= (0.0094 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\
 &= \mathbf{0 \text{ lb SO}_x/\text{qtr}} \\
 &= (0.0094 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\
 &= \mathbf{1 \text{ lb SO}_x/\text{year}}
 \end{aligned}$$

Post Project Potential to Emit (PE2) (C-3953-14-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO _x	1.90	45.5	24	95
CO	1.14	27.3	14	57
VOC	0.63	15.0	8	31
PM ₁₀	0.06	1.5	1	3
SO _x	0.02	0.4	0	1

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 will be equal to zero.

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)						
Permit Unit	NO _x	CO	VOC	PM ₁₀	SO _x	NH ₃
C-3953-10-0	143,951	601,810	34,489	80,656	16,694	219,972
C-3953-11-0	143,951	601,810	34,489	80,656	16,694	219,972
C-3953-12-0	513	1,727	201	233	132	0
C-3953-13-0	108	14	12	2	0	0
C-3953-14-0	95	57	31	3	1	0
Post-project SSPE (SSPE2)	288,618	1,205,418	69,222	161,550	33,521	439,944

5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a major source is a stationary source with post-project emissions or a Post-project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values.

Major Source Determination					
	NO _x (lb/year)	CO (lb/year)	VOC (lb/year)	PM ₁₀ (lb/year)	SO _x (lb/year)
Post-project SSPE (SSPE2)	288,618	1,205,418	69,222	161,550	33,521
Major Source Threshold	50,000	200,000	50,000	140,000	140,000
Major Source?	Yes	Yes	Yes	Yes	No

6. Annual Baseline Emissions (BE)

Per District Rule 2201, Section 3.7, the baseline emissions, for a given pollutant, shall be equal to the pre-project potential to emit for:

- Any emission unit located at a non-major source,
- Any highly utilized emission unit, located at a major source,
- Any fully-offset emission unit, located at a major source, or
- Any clean emission unit located at a major source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22 of District Rule 2201

As shown above, this facility will be a major source for NO_x, CO, VOC, and PM₁₀ emissions after this project. However, since the units in this project are all new emissions units, there are no historical actual emissions or pre-project potential to emit. Therefore, the baseline NO_x, CO, VOC, PM₁₀ and SO_x emissions will be set equal to the following:

BE = 0 lb/year

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

Since this is a new facility, this project cannot be considered a Major Modification.

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

VIII. COMPLIANCE:

Rule 1080 Stack Monitoring

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The two CTGs will be equipped with operational CEMs for NO_x, CO, and O₂. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_x, CO and O₂ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]
- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]
- The NO_x, CO and O₂ CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]
- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]
- The owner/operator shall perform a relative accuracy test audit (RATA) for NO_x, CO and O₂ as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]
- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]
- Results of the CEM system shall be averaged over a one hour period for NO_x emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

- Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]
- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]
- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]
- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]
- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]
- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_x emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

ii. C-3953-12 (Boiler)

The boiler will be equipped with operational CEMs for NO_x, CO, and O₂. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NO_x, CO, and O₂. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]
- {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]
- {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]
- {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]
- {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]
- {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

Rule 1081 Source Sampling

This Rule requires adequate and safe facilities for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_x, CO, and O₂ analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]
- Source testing to measure startup NO_x, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]
- Source testing (with and without duct burner firing) to measure the NO_x, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O₂) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

- Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]
- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001]
- Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]
- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
- The following test methods shall be used: NO_x - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O₂ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

ii. C-3953-12-0 (Boiler)

The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_x, CO, and O₂ analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]
- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Rule 1100 Equipment Breakdown

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1100 Conditions:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Rule 2010 Permits Required

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of an ATC application, Avenal Power Center, LLC is complying with the requirements of this Rule.

Rule 2201 New and Modified Stationary Source Review Rule

A. BACT:

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

- a. Any new emissions unit with a potential to emit exceeding two pounds per day,
- b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
- c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
- d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install two new combustion turbine generators with PEs greater than 2 lb/day for NO_x, CO, VOC, PM₁₀, and SO_x. BACT is triggered for NO_x, CO, VOC, PM₁₀, and SO_x criteria pollutants since the PEs are greater than 2 lbs/day, and since the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

The PE of ammonia is greater than two pounds per day for the two CTGs. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_x. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

ii. C-3953-12-0 (Boiler)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new boiler with a PE greater than 2 lb/day for NO_x, CO, VOC, PM₁₀, and SO_x. BACT is triggered for NO_x, CO, VOC, and PM₁₀ criteria pollutants since the PEs are greater than 2 lbs/day, and since the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new diesel-fired IC engine (fire pump) with a PE greater than 2 lb/day for NO_x, CO, and VOC. BACT is triggered for NO_x, CO, and VOC criteria pollutants since the PEs are greater than 2 lbs/day, and since the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new natural gas-fired IC engine (generator) with a PE greater than 2 lb/day for NO_x, CO, and VOC. BACT is triggered for NO_x, CO, and VOC criteria pollutants since the PEs are greater than 2 lbs/day, and since the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

2. BACT Guidance

The District BACT Clearinghouse was created to assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis. The Clearinghouse will include, for various class and category of sources, available control technologies and methods that meet one or more of the following conditions:

- Have been achieved in practice for such emissions unit and class of source; or
- Are contained in any SIP approved by the EPA for such emissions unit category and class of source; or
- Are any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source.

Attachment E will include the BACT Guidelines from the BACT Clearinghouse applicable to the new emissions units associated with this project.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

BACT Guideline 3.4.2 is applicable to the two combustion turbine generator installations [Gas Fired Turbine = or > 50 MW, Uniform Load, with Heat Recovery].

ii. C-3953-12-0 (Boiler)

BACT Guideline 1.1.2 is applicable to the 37.4 MMBtu/hr boiler. [Boiler - > 20 MMBtu/hr, Natural gas-fired, base-loaded or with small load swings.]

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

BACT Guideline 3.1.4, applies to the diesel-fired emergency IC engine powering a fire pump. [Emergency Diesel I.C. Engine Driving a Fire Pump]

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

BACT Guideline 3.1.8, applies to the natural gas-fired emergency IC engine powering an electrical generator. [Emergency Gas-Fired I.C. Engine > or = 250 hp, Lean Burn]

3. Top-Down Best Available Control Technology (BACT) Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

For Permit Units C-3953-10-0 and -11-0 see Attachment F.

For Permit Unit C-3953-12-0 see Attachment F.

For Permit Unit C-3953-13-0 see Attachment F.

For Permit Unit C-3953-14-0 see Attachment F.

4. BACT Summary:

i. C-3953-10-0 and C-3953-11-0 (Turbines)

BACT has been satisfied by the following:

NO_x: 2.0 ppmv @ 15% O₂ (1-hour rolling average, except during startup/shutdown) with Dry Low NO_x Combustors, SCR with ammonia injection and natural gas fuel.

CO: 2.0 ppmv @ 15% O₂ (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

VOC: 1.5 ppmv @ 15% O₂ (without duct burner firing; 3-hour rolling average).
2.0 ppmv @ 15% O₂ (with duct burner firing; 3-hr rolling average).

PM₁₀: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

SO_x: PUC regulated natural gas with a sulfur content of 1.0 gr/100 scf or less

ii. C-3953-12-0 (Boiler)

BACT has been satisfied by the following:

NO_x: 9.0 ppmv @ 15% O₂ with Ultra Low NO_x burners and natural gas fuel.

CO: Natural gas fuel.

VOC: Natural gas fuel.

PM₁₀: Natural gas fuel.

SO_x: Natural gas fuel.

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

BACT has been satisfied by the following:

NO_x: Certified NO_x emissions of 6.9 g/hp·hr or less

CO: No CO control. Any add on CO control device would void the Underwriters Laboratory (UL) certification.

VOC: No VOC control. Any add on VOC control device would void the Underwriters Laboratory (UL) certification.

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

BACT has been satisfied by the following:

NO_x: = or < 1.0 g/bhp-hr (lean burn natural gas fired engine, or equal)

CO: 90% control efficiency (oxidation catalyst, or equal)

VOC: 90% control efficiency (oxidation catalyst, or equal)

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

C. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_x and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_x and 29,200 lbs/year for PM₁₀. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_x, CO, VOC, PM₁₀, and SO_x emissions. Therefore, offset calculations are necessary.

Offset Determination					
	NO _x (lb/year)	CO (lb/year)	VOC (lb/year)	PM ₁₀ (lb/year)	SO _x (lb/year)
Post-project SSPE (SSPE2)	288,618	1,205,418	69,222	161,550	33,521
Offset Threshold	20,000	200,000	20,000	29,200	54,750
Offsets Required?	Yes	Yes	Yes	Yes	No

2. Quantity of Offsets Required:

Per District Rule 2201, Section 4.6.1, emission offsets shall not be required for increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

As shown in section VIII.G below, the increase in CO emissions associated with this stationary source project does not cause or contribute to a violation of Ambient Air Quality Standards. CO emissions are not addressed in any Reasonable Further Progress Plans. Therefore, this stationary source project qualifies for the offset exemption listed in Section 4.6.1.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_x, CO, VOC, and PM₁₀ is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = $([SSPE2 - \text{Offset Threshold}] + ICCE) \times DOR$, for all new or modified emissions units in the project,

Where,

SSPE2 = Post Project Facility Potential to Emit, (lb/year)

ICCE = Increase in Cargo Carrier Emissions, (lb/year)

DOR = Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit units C-3953-13-0 and C-3953-14-0 will be exempt from providing offsets and the emissions associated with these permit units contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offset = $([SSPE2 - \text{Emergency Equipment} - \text{Offset Threshold}] + ICCE) \times DOR$, for all new or modified emissions units in the project,

NO_x Offset Calculations:

NO_x SSPE2 = 288,618 lb/year

C-3953-13-0 (NO_x) = 108 lb/year

C-3953-14-0 (NO_x) = 95 lb/year

NO_x offset threshold = 20,000 lb/year

Offsets = $[288,618 - (108) - (95) - 20,000]$
= 268,415 lb/year * DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

Offsets = $(268,415 \text{ lb/year} \div 4 \text{ qtr/year}) \times DOR$
= 67,103.75 lb/qtr * DOR

PE_{1st Qtr} = 67,103.75 lbs of NO_x * DOR

PE_{2nd Qtr} = 67,103.75 lbs of NO_x * DOR

PE_{3rd Qtr} = 67,103.75 lbs of NO_x * DOR

PE_{4th Qtr} = 67,103.75 lbs of NO_x * DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2:1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3:1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's

Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of NO_x ERC's that need to be withdrawn is:

Offsets Required = 268,415 lb-NO_x/year x 1.5
 Offsets Required = 402,623 lb-NO_x/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	<u>1st Quarter</u> (lb/qtr)	<u>2nd Quarter</u> (lb/qtr)	<u>3rd Quarter</u> (lb/qtr)	<u>4th Quarter</u> (lb/qtr)	<u>Total</u> (lb/year)
NO _x	100,655	100,656	100,656	100,656	402,623

The applicant has stated that the facility plans to use ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 to offset the increases in NO_x emissions associated with this project. The above Certificates have available quarterly NO_x credits as follows:

Offset Proposal					
	<u>1st Quarter</u> (lb/qtr)	<u>2nd Quarter</u> (lb/qtr)	<u>3rd Quarter</u> (lb/qtr)	<u>4th Quarter</u> (lb/qtr)	<u>Total</u> (lb/year)
ERC #C-899-2	2,243	2,243	2,243	2,243	8,972
ERC #C-902-2	13,879	6,131	1,086	8,539	29,635
ERC #N-720-2	0	9	1,255	437	1,701
ERC #N-722-2	0	1,166	88,317	1,422	90,905
ERC #N-726-2	0	0	4,728	0	4,728
ERC #N-728-2	10,542	3,731	2,487	5,171	21,931
ERC #S-2814-2	6,121	13,869	18,914	11,461	50,365
ERC #S-2321-2*	51,000	51,000	51,000	51,000	204,000
Total	83,784	78,147	170,027	80,269	412,227

*ERC certificate split from this ERC.

Project NO_x offset requirements

The applicant states that NO_x ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 will be utilized to supply the NO_x offset requirements.

Per Rule 2201 Section 4.13.8, Actual Emission Reductions (i.e. ERCs) that occurred from April through November (i.e. 2nd and 3rd Quarter), inclusive, may be used to offset increases in NO_x or VOC during any period of the year. Since 3rd quarter NO_x ERCs will be used to offset NO_x emissions, the above applies to the NO_x ERCs.

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	<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
NO _x Emissions to be offset: (at a 1.5:1 DOR):	100,655	100,656	100,656	100,656
Available ERCs from certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2*:	83,784	78,147	170,027	80,269
3 rd qtr. ERCs applied to 1 st qtr. ERCs:	16,871	0	-16,871	0
3 rd qtr. ERCs applied to 2 nd qtr. ERCs:	0	22,509	-22,509	0
3 rd qtr. ERCs applied to 4 th qtr. ERCs:	0	0	-20,387	20,387
Remaining ERCs from certificates S-2321-2:	0	0	9,604	0
Remaining NO _x emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly NO_x emissions increases associated with this project.

VOC Offset Calculations:

VOC SSPE2 = 69,222 lb/year
 C-3953-13-0 (VOC) = 12 lb/year
 C-3953-14-0 (VOC) = 31 lb/year
 VOC offset threshold = 20,000 lb/year

$$\begin{aligned} \text{Offsets} &= [69,222 - (12) - (31) - 20,000] \\ &= 49,179 \text{ lb/year} * \text{DOR} \end{aligned}$$

Calculating the appropriate quarterly emissions to be offset is as follows:

$$\begin{aligned} \text{Offsets} &= (49,179 \text{ lb/year} \div 4 \text{ qtr/year}) * \text{DOR} \\ &= 12,294.75 \text{ lb/qtr} * \text{offset ratio} \end{aligned}$$

PE_{1st Qtr} = 12,294.75 lbs of VOC * DOR
 PE_{2nd Qtr} = 12,294.75 lbs of VOC * DOR
 PE_{3rd Qtr} = 12,294.75 lbs of VOC * DOR
 PE_{4th Qtr} = 12,294.75 lbs of VOC * DOR

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Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2:1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3:1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of VOC ERC's that need to be withdrawn is:

PE_{1st Qtr} = 12,294.75 lbs of VOC * 1.5 = 18,442 lbs
 PE_{2nd Qtr} = 12,294.75 lbs of VOC * 1.5 = 18,442 lbs
 PE_{3rd Qtr} = 12,294.75 lbs of VOC * 1.5 = 18,442 lbs
 PE_{4th Qtr} = 12,294.75 lbs of VOC * 1.5 = 18,442 lbs

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1 st Quarter (lb/qtr)	2 nd Quarter (lb/qtr)	3 rd Quarter (lb/qtr)	4 th Quarter (lb/qtr)	Total (lb/year)
VOC	18,442	18,442	18,442	18,442	73,769

The applicant has stated that the facility plans to use ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 to offset the increases in VOC emissions associated with this project. The above Certificates have available quarterly VOC credits as follows:

Offset Proposal					
	1 st Quarter (lb/qtr)	2 nd Quarter (lb/qtr)	3 rd Quarter (lb/qtr)	4 th Quarter (lb/qtr)	Total (lb/year)
ERC #C-897-1	45	45	45	45	180
ERC #C-898-1	5,480	6,496	4,696	6,616	23,288
ERC #N-724-1	0	0	241	0	241
ERC #N-725-1	0	0	709	0	709
ERC #S-2812-1	31,432	31,424	31,417	31,417	125,690
ERC #S-2813-1	12,500	12,500	12,500	12,500	50,000
ERC #S-2817-1	11,431	11,424	11,417	11,417	45,689
Total	60,887	61,887	61,022	61,991	245,787

Project VOC offset requirements

The applicant states that NO_x ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 will be utilized to supply the VOC offset requirements.

	<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
VOC Emissions to be offset: (at a 1.5:1 DOR):	18,442	18,442	18,442	18,442
Available ERCs from certificates C-897-1, C-898-1, N-724-1, N-725-1,	5,525	6,541	5,691	6,661
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
VOC Emissions to be offset: (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
Available ERCs from certificates S-2812-1, S-2813-1, and S-2817-1	55,363	55,348	55,334	55,334
Remaining ERCs from certificates S-2812-1, S-2813-1, and S-2817-1:	42,446	43,447	42,583	43,553
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

PM₁₀ Offset Calculations:

PM₁₀ SSPE2 = 161,545 lb/year
 C-3953-13-0 (PM₁₀) = 2 lb/year
 C-3953-14-0 (PM₁₀) = 3 lb/year
 PM₁₀ Offset threshold = 29,200 lb/year

$$\begin{aligned} \text{Offsets} &= [(161,545 - (2) - (3) - 29,200 + 0) \times \text{DOR}] \\ &= 132,340 \text{ lb/year} \times \text{DOR} \end{aligned}$$

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

$$\begin{aligned} \text{Offsets} &= (132,340 \text{ lb/year} \div 4 \text{ qtr/year}) \times \text{DOR} \\ &= 33,085 \text{ lb/qtr} \times \text{offset ratio} \end{aligned}$$

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PE_{1st Qtr} = 33,085 lbs of PM₁₀ * DOR
 PE_{2nd Qtr} = 33,085 lbs of PM₁₀ * DOR
 PE_{3rd Qtr} = 33,085 lbs of PM₁₀ * DOR
 PE_{4th Qtr} = 33,085 lbs of PM₁₀ * DOR

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM₁₀ ERCs that need to be withdrawn is:

$$\begin{aligned} \text{Offsets Required (lb/year)} &= 132,340 \text{ lb/year} \times 1.5 \\ &= 198,510 \text{ lb/year} \end{aligned}$$

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Quantity of Offsets Required					
	<u>1st Quarter</u> (lb/qtr)	<u>2nd Quarter</u> (lb/qtr)	<u>3rd Quarter</u> (lb/qtr)	<u>4th Quarter</u> (lb/qtr)	<u>Total</u> (lb/year)
PM ₁₀	49,628	49,627	49,627	49,628	198,510

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM₁₀ emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

Offset Proposal					
	<u>1st Quarter</u> (lb/qtr)	<u>2nd Quarter</u> (lb/qtr)	<u>3rd Quarter</u> (lb/qtr)	<u>4th Quarter</u> (lb/qtr)	<u>Total</u> (lb/year)
ERC #C-896-4	80	80	80	80	320
ERC #N-721-4	0	0	3,215	0	3,215
ERC #N-723-4	0	0	985	0	985
ERC #S-2791-5	92,179	23,666	69,157	96,288	281,290
ERC #S-2790-5	12,862	491	0	8,499	21,852
ERC #S-2789-5	6	14	12	8	40
ERC #S-2788-5	5	7	3	6	21
ERC #N-762-5	21,000	21,000	21,000	21,000	84,000
Total	126,131	45,256	94,449	125,877	391,723

Project PM₁₀ offset requirements

The applicant states either PM₁₀ ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM₁₀ offset requirements.

	<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
PM ₁₀ Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM ₁₀ emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM₁₀ and PM₁₀ precursors (i.e. SO_x) may be allowed. The applicant is proposing to use interpollutant offsets SO_x for PM₁₀ at an interpollutant ratio of 1.0:1 (see Attachment H). Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_x ERCs are being used to offset PM₁₀ emissions, the above applies to the SO_x ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

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	<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
Remaining PM ₁₀ Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM ₁₀ emissions to be offset with SO _x ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO _x :PM ₁₀ ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM ₁₀ emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO _x :PM ₁₀ ratio):	15,677	28,037	24,334	20,037
	<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO _x :PM ₁₀ ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1 st qtr. ERCs applied to 2 nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO _x :PM ₁₀ ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_x and PM₁₀ emissions increases associated with this project.

Offset Conditions:

The following conditions will ensure compliance with the offset requirements of this rule:

- Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide NO_x (as NO₂) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]
- Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]
- Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide PM₁₀ emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SO_x ERC's may be used to offset PM₁₀ increases at an interpollutant ratio of 1.0 lb-SO_x : 1.0 lb-PM₁₀. [District Rule 2201]
- ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

D. Public Notification:

1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Any project which results in the offset thresholds being surpassed (Offset Threshold Notification), and/or
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

a. New Major Source Notice Determination

New Major Sources are new facilities, which are also Major Sources.

As shown in Section VII.C.6 above, the SSPE2 is greater than the Major Source threshold for NO_x, CO, VOC, and PM₁₀. Therefore, public noticing is required for this project for new Major Source purposes because this facility is becoming a new Major Source.

b. Major Modification

As demonstrated in Section VII.C.7 above, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE Notification

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. The potential to emit for each unit is summarized in the table below.

Post-Project Potential to Emit						
Permit Unit	NO _x (lb/day)	CO (lb/day)	VOC (lb/day)	PM ₁₀ (lb/day)	SO _x (lb/day)	NH ₃ (lb/day)
C-3953-10-0	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-11-0	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-12-0	4.9	16.6	1.9	2.2	1.3	0
C-3953-13-0	51.8	6.8	5.8	0.9	0.1	0
C-3953-14-0	45.5	27.3	15.0	1.5	0.4	0
Threshold (lb/day)	100	100	100	100	100	100
Notification Required?	Yes	Yes	Yes	Yes	Yes	Yes

According to the table above, permit units C-3953-10-0 and -11-0 will each have a Potential to Emit greater than 100 lb/day for NO_x, CO, VOC, PM₁₀, SO_x, or NH₃ emissions. Therefore, public noticing will be required for PE > 100 lbs/day purposes.

e. Offset Threshold

Public notification is required if the Pre-Project Stationary Source Potential to Emit (SSPE1) is increased from a level below the offset threshold to a level exceeding the emissions offset threshold, for any pollutant.

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO _x	0	288,618	20,000 lb/year	Yes
CO	0	1,205,418	200,000 lb/year	Yes
VOC	0	69,222	20,000 lb/year	Yes
PM ₁₀	0	161,550	29,200 lb/year	Yes
SO _x	0	33,521	54,750 lb/year	No

As detailed above, offset thresholds were surpassed for NO_x, CO, VOC, and PM₁₀ emissions with this project; therefore public noticing is required for offset purposes.

f. SSIPE Notification

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary Source Potential to Emit (SSPE1), i.e. $SSIPE = SSPE2 - SSPE1$. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

SSIPE Notification					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO _x	288,618	0	288,618	20,000 lb/year	Yes
CO	1,205,418	0	1,205,418	20,000 lb/year	Yes
VOC	69,222	0	69,222	20,000 lb/year	Yes
PM ₁₀	161,550	0	161,550	20,000 lb/year	Yes
SO _x	33,521	0	33,521	20,000 lb/year	Yes

As demonstrated above, the SSIPE's for NO_x, CO, VOC, PM₁₀ and SO_x emissions were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Requirements

Section 5.5 details the actions taken by the District when public noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. New Major Source, PE's > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

E. Daily Emission Limits:

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. Per Sections 3.15.1 and 3.15.2, the DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis.

Proposed Rule 2201 (DEL) Conditions:

i. C-3953-10-0 and C-3953-11-0 (Turbines)

For the turbines, the DELs for NO_x, CO, VOC, PM₁₀, SO_x, and NH₃ will consist of lb/day and/or emission factors.

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) – 17.20 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O₂; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ – 11.78 lb/hr; or SO_x (as SO₂) – 6.65 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]
- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) – 13.55 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) – 3.34 lb/hr and 1.4 ppmvd @ 15% O₂; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ – 8.91 lb/hr; or SO_x (as SO₂) – 5.23 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]
- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_x (as NO₂) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM₁₀ – 11.78 lb/hr; SO_x (as SO₂) – 6.652 lb/hr; or NH₃ – 32.13 lb/hr. [District Rules 2201 and 4703]
- Daily emissions from the CTG shall not exceed the following limits: NO_x (as NO₂) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM₁₀ – 282.7 lb/day; SO_x (as SO₂) – 159.6 lb/day, or NH₃ – 771.1 lb/day. [District Rule 2201]
- Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NO_x (as NO₂) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM₁₀ – 282.7 lb/day; SO_x (as SO₂) – 159.6 lb/day, or NH₃ – 771.1 lb/day. [District Rule 2201]
- The ammonia (NH₃) emissions shall not exceed 10 ppmvd @ 15% O₂ over a 24 hour rolling average. [District Rule 2201]
- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

- Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

In addition to the daily emissions limits specified above, the following conditions will also be included to ensure continued compliance for the proposed turbines:

- Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_x (as NO₂) – 143,951 lb/year; CO – 601,810 lb/year; VOC – 34,489 lb/year; PM₁₀ – 80,656 lb/year; or SO_x (as SO₂) – 16,694 lb/year; or NH₃ – 208,708 lb/year. [District Rule 2201]
- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]
- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

ii. C-3953-12-0 (Boiler)

The DELs for the boiler will consist of lb/MMBtu and ppmv emissions limits. This will be sufficient to establish a maximum daily potential to emit based on the maximum daily fuel use limit.

- Emission rates from this unit shall not exceed any of the following limits: NO_x (as NO₂) - 9.0 ppmvd @ 3% O₂ or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O₂; CO - 50.0 ppmvd @ 3% O₂ or 0.037 lb/MMBtu; PM₁₀ - 0.005 lb/MMBtu; or SO_x (as SO₂) - 0.00282 lb/MMBtu. [District Rules 2201, 4305, 4306, and 4351]

In addition the following permit conditions will appear on the permit:

- {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

iii. C-3953-13-0 (Diesel IC engine fire pump)

For the emergency IC engine powering a fire pump, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NO_x/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]
- Emissions from this IC engine shall not exceed 0.059 g-PM₁₀/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]
- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-0 (Natural gas IC engine electrical generator)

For the emergency IC engine powering a generator, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NO_x/bhp-hr, 0.034 g-PM₁₀/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]
- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

F. Compliance Certification:

Section 4.15.2 of this Rule requires the owner of a new major source or a source undergoing a major modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed above, this facility is a new major source; therefore this requirement is applicable. Included in Attachment I is Avenal Power Center's certification for the Avenal Energy Project.

G. Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment G of this document for the AQIA summary sheet.

The AQIA performed for this project was analyzed based on the facility's preliminary proposal. The facility originally proposed CO emissions from the two CTG's to be limited to 4.0 ppmvd @ 15% O₂. However, due to comments made during the public notice period, the facility limited their CO emissions to 2.0 ppmvd @ 15% O₂. Since the new proposed emission factor is lower than the original emission factor and will not result in an increase in air pollutants, a new AQID will not be required to be performed for this project.

The proposed location is in an attainment area for NO_x, CO, and SO_x. As shown by the table below, the proposed equipment will not cause a violation of an air quality standard for NO_x, CO, or SO_x.

AAQA Results Summary					
Pollutant	1 hr Average	3 hr Average	8 hr Average	24 hr Average	Annual Average
CO	Pass	N/A	Pass	N/A	N/A
NO _x	Pass	N/A	N/A	N/A	Pass
SO _x	Pass	Pass	N/A	Pass	Pass

The proposed location is in a non-attainment area for PM₁₀. The increase in the ambient PM₁₀ concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels (µg/m ³) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM ₁₀	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions (µg/m ³)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM ₁₀	0.38	1.6	N/A	N/A	N/A

As shown, the calculated contribution of PM₁₀ will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

H. Compliance Assurance:

1. Source Testing

i. C-3953-10-0 and C-3953-11-0

District Rule 4703 requires NO_x and CO emission testing as well as percent turbine efficiency testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM₁₀ emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_x, CO, VOC, PM₁₀, and ammonia slip will be required within 60 days after the end of the commissioning period and at least once every 12 months thereafter.

Also, initial source testing of NO_x, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for NO_x, CO, and O₂. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of NO_x and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be documented or monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

40 CFR Part 60 subpart Db requires NO_x testing for the duct burners. The District will accept the NO_x source testing required by District Rule 4703 as equivalent to NO_x testing required by 40 CFR 60 subpart Db.

ii. C-3953-12-0

This unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*. Source testing requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-0 and C-3953-14-0

Pursuant to District Policy APR 1705, source testing is not required for emergency standby IC engines to demonstrate compliance with Rule 2201.

2. Monitoring

i. C-3953-10-0 and C-3953-11-0

Monitoring of NO_x emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_x.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK and District Rule 4703 requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to allow the facility to demonstrate compliance with the limit by providing gas purchase contracts, supplier certification, tariff sheet or transportation contract; or, if these documents cannot be provided, physically monitor the fuel sulfur content weekly for eight consecutive weeks and semi-annually thereafter if the fuel sulfur content remains below 1.0 gr/scf. Avenal Power Center, LLC will be operating these turbines in compliance with the fuel sulfur content monitoring requirements as described in the Rule 4001, Subpart KKKK discussion below. Therefore, compliance with the monitoring requirements will be satisfied.

ii. C-3953-12-0

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to monitoring requirements. Monitoring requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-0 and C-3953-14-0

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

i. C-3953-10-0 and C-3953-11-0

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

ii. C-3953-12-0

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

The following permit condition will be listed on permit as follows:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

iii. C-3953-13-0 and C-3953-14-0

Recordkeeping is required to demonstrate compliance with the offset, public notification, and daily emission limit requirements of Rule 2201. As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, these IC engines are subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

4. Reporting

i. C-3953-10-0 and C-3953-11-0

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedences of the NO_x emission limit of the permit. Such reporting will be required.

ii. C-3953-12-0

No reporting is required to demonstrate compliance with Rule 2201.

iii. C-3953-13-0 and C-3953-14-0

No reporting is required to demonstrate compliance with Rule 2201.

Rule 2520 Federally Mandated Operating Permits

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0:

- Section 2.3 states, "Any major source." The facility will be a major source for NO_x, CO, VOC, and PM₁₀ after this project.
- Section 2.4 states, "Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA..." The turbines are subject to NSPS.
- Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.
- Section 2.6 states, "Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act." This facility is required to obtain a PSD permit from the EPA.

Pursuant to Rule 2520 section 5.3.1 Avenal Power Center must submit a Title V application within 12 months of commencing operations. No action is required at this time.

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Rule 2540 Acid Rain Program

The proposed CTG's are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in November of 2011.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_x and SO_x emissions and a relatively small quantity of SO_x allowances (from a national SO_x allowance bank) will be required as well as the use of a NO_x CEM.

The following condition will be placed on permits C-3953-10-0, -11-0 and -14-0 to ensure that Avenal Power Center, LLC submits an application to comply with the requirements of the acid rain program within the appropriate timeframe:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998." The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.⁸

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Toxics

⁸ These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).

Policy, May 1991; Rule 2-1-316). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVACPD toxic air contaminant list has been evaluated.

Noncriteria pollutant emission factors for the analysis of emissions from the gas turbines were obtained from AP-42 (Table 3.1-3, 4/00, and Table 3.4-1 of the Background Document for Section 3.1), from the California Air Resources Board's CATEF database for gas turbines, and from source tests on a similar turbine. Specifically, factors for all pollutants except formaldehyde, hexane, propylene, and naphthalene and other PAHs were taken from AP-42.⁹ AP-42 did not contain factors for hexane or propylene, and did not include speciated data for PAHs. Factors for these pollutants and for naphthalene were taken from the CATEF database (mean values). The emission factor for formaldehyde was taken from the results of a June 2000 source test on a dry Low NO_x combustor-equipped large frame turbine.

Hazardous Air Pollutant Emissions (per CATEF)
Avenal Energy Project – GE Frame 7 (with Duct Burners)

Hazardous Air Pollutant	CATEF Emission Factor (lb/MMSCF) ⁽¹⁾	Maximum Hourly Emissions per Turbine (lb/hr) ⁽²⁾	Maximum Annual Emissions per Turbine (tpy) ⁽³⁾	Maximum Annual Emissions both Turbines (tpy)
Acetaldehyde	4.08E-02	0.09	0.33	0.67
Acrolein	3.69E-03	0.01	0.03	6.04E-02
Benzene	3.33E-03	0.01	0.03	5.45E-02
1,3-Butadiene	4.39E-04	9.38E-04	3.59E-03	7.19E-03
Ethyl benzene	3.26E-02	0.07	0.27	0.53
Formaldehyde	1.65E-01	0.35	1.35	2.70
Hexane	2.59E-01	0.55	2.12	4.24
Naphthalene	1.33E-03	2.84E-03	1.09E-02	2.18E-02
Polycyclic aromatic hydrocarbons (PAH)	---	---	---	---
Anthracene	3.38E-05	7.22E-05	2.77E-04	5.53E-04
Benzo(a)anthracene	2.26E-05	4.83E-05	1.85E-04	3.70E-04
Benzo(a)pyrene	1.39E-05	2.97E-05	1.14E-04	2.28E-04
Benzo(b)fluoranthrene	1.13E-05	2.41E-05	9.25E-05	1.85E-04
Benzo(k)fluoranthrene	1.10E-05	2.35E-05	9.00E-05	1.80E-04
Chrysene	2.52E-05	5.38E-05	2.06E-04	4.12E-04
Dibenz(a,h)anthracene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Indeno(1,2,3-cd)pyrene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Propylene oxide	2.96E-02	6.32E-02	2.42E-01	0.48
Toluene	1.33E-01	0.28	1.09	2.18
Xylenes	6.53E-02	0.14	0.53	1.07
Total			6.01	12.02

(1) From AP-42 and CATEF databases and source tests.

(2) Based on a maximum hourly turbine fuel use of 2,224.1 MMBtu/hr (with duct burner) and fuel HHV of 1,021 Btu/scf. (2.14 MMscf/hr)

⁹ Factors for acrolein and benzene reflect the use of an oxidation catalyst and were taken from Table 3.4-1 of the Background Document for Section 3.1.

- (3) Based on a maximum annual turbine fuel use of 16,711,728 MMBtu/year (with duct burner) and fuel HHV of 1,021 Btu/scf. (16,368 MMscf/yr)

Although the turbines/HRSGs will be equipped with oxidation catalyst systems, only the acrolein and benzene emission factors reflect any control effectiveness. As discussed above, these factors are based on test data rather than any assumption regarding catalyst control efficiency.

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the Avenal Power Center, LLC Project will not be a major air toxics source and the provisions of this rule do not apply.

Rule 4001 New Source Performance Standards

40 CFR 60 – Subpart Dc

NSPS Subpart Dc applies to steam generating units that are constructed, reconstructed, or modified after 6/9/89 and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc has standards for SO_x and PM₁₀.

60.42c – Standards for Sulfur Dioxide

Since coal is not combusted by the boiler in this project, the requirements of this section are not applicable.

60.43c – Standards for Particulate Matter

The boiler is not fired on coal, combusts mixtures of coal with other fuels, combusts wood, combusts mixture of wood with other fuels, or oil; therefore it will not be subject to the requirements of this section.

60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide.

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.46c – Emission Monitoring for Sulfur Dioxide

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.47c – Emission Monitoring for Particulate Matter

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

- (1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

The design heat input capacity and type of fuel combusted at the facility will be listed on the unit's equipment description. No conditions are required to show compliance with this requirement.

- (2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

This requirement is not applicable since the units are not subject to §60.42c or §40.43c.

- (3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility has not proposed an annual capacity factor; therefore one will not be required.

- (4) Notification if an emerging technology will be used for controlling SO₂ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

This requirement is not applicable since the units will not be equipped with an emerging technology used to control SO₂ emissions.

Section 60.48 c (g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The following conditions will be added to the permit to assure compliance with this section.

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]
- Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

Section 60.48 c (i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 4306 requires that records be kept for five years.

40 CFR 60 – Subpart GG

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines also meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

40 CFR 60 - Subpart IIII

§60.4200 - Applicability

40 CFR Part 60 Subpart IIII applies to all owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

- 1) Manufactured after April 1, 2006, if not a fire pump engine.
- 2) Manufactured as a National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Since the proposed engines will be installed after July 11, 2005 and will be manufactured after April 1, 2006, this subpart applies.

All of the applicable standards of this subpart are less restrictive than current District requirements. This engine will comply with all current District standards so further discussion is required.

40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating of 1,794.5 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_x) and sulfur dioxide (SO_x) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_x emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_x. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_x emissions limit of 15 ppmvd @ 15% O₂ or 54 ng/J of useful output (0.43 lb/MWh).

Avenal Power Center is proposing a NO_x emission concentration limit of 2.0 ppmvd @ 15% O₂ for each turbine. Therefore, the proposed turbines will be operating in compliance with the NO_x emission requirements of this subpart. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) – 17.44 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) – 6.13 lb/hr and 2.0 ppmvd @ 15% O₂; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ – 11.78 lb/hr; or SO_x (as SO₂) – 6.72 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]
- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) - 13.28 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) - 3.23 lb/hr and 1.4 ppmvd @ 15% O₂; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ – 8.97 lb/hr; or SO_x (as SO₂) – 5.11 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 60.4330 - Standards for Sulfur Dioxide:

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

- (1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO₂ in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or
- (2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input.

Avenal Power Center is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the SO_x emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – NO_x Compliance Demonstration, with Water or Steam Injection:

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_x emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Avenal Power Center does not use water or steam injection in their turbines therefore; the requirements of this section are not applicable to the turbines in this project.

Section 60.4340 – NO_x Compliance Demonstration, without Water or Steam Injection:

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

- (1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
- (2) Continuous parameter monitoring

Avenal Power Center has proposed to install a CEMS system as described in §§60.4335(b) and 60.4345 therefore; the following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_x, CO and O₂ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_x diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_x diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_x monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of

two quadrants) are required for each monitor to validate the NO_x emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

Avenal Power Center will be required to install and operate a NO_x CEMS in accordance with the requirements of this section. As discussed above, Avenal Power Center is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_x, CO and O₂ CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]
- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

Section 60.4350 – CEMS Data and Excess NO_x Emissions:

Section 60.4350 states that for purposes of identifying excess emissions:

- (a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O₂ concentration exceeds 19.0 percent O₂ (or the hourly average CO₂ concentration is less than 1.0 percent CO₂), a diluent cap value of 19.0 percent O₂ or 1.0 percent CO₂ (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_x concentrations to 15 percent O₂ is not allowed.

(d) If you have installed and certified a NO_x diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_x emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

Avenal Power Center is proposing to monitor the NO_x emissions rates from the turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_x emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

Section 60.4355 – Parameter Monitoring Plan:

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_x emissions. As discussed above, Avenal Power Center is proposing to install CEMS on each of these turbines that will directly measure NO_x emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input for units located in continental areas and 180 ng SO₂/J (0.42 lb SO₂/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

- (a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO₂/J (0.42 lb SO₂/MMBtu) heat input for noncontinental areas; or
- (b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO₂/J (0.060 lb SO₂/MMBtu) heat input for continental areas or 180 ng SO₂/J (0.42 lb SO₂/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

Avenal Power Center is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. Primarily, the natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit. However, Avenal Power Center has asked that the option of either using a purchase contract, tariff sheet or transportation contract or actually physically monitoring the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

- (a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).
- (b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.
- (c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in these turbines, Avenal Power Center is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. Avenal Power Center is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for the turbines. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_x Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, Avenal Power Center is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_x emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_x emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_x emission rate" is the arithmetic average of the average NO_x emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_x emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_x emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_x emission rate" is the arithmetic average of all hourly NO_x emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_x emissions rates for the preceding 30 unit operating days if a valid NO_x emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_x concentration, CO₂ or O₂ concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_x emission controls. Avenal Power Center is not proposing to monitor combustion parameters that document proper operation of the NO_x emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_x concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_x or O₂ (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_x Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

Avenal Power Center will be following the definitions and procedures specified above for determining periods of excess SO_x emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. Avenal Power Center is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_x emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_x Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Subsequent NO_x performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set forth the requirements for the methods that are to be used during source testing.

Avenal Power Center will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NO_x, CO and VOC emission rates (lb/hr and ppmvd @ 15% O₂), NH₃ emission rate (ppmvd @ 15% O₂) and PM₁₀ emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- The following test methods shall be used: NO_x - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM₁₀ - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O₂ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_x-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). Avenal Power Center has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_x emission controls. As discussed above, Avenal Power Center is proposing to install a CEMS system to monitor the NO_x emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_x Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO₂ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

- (i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or
 - (ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).
-

Avenal Power Center is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO₂ concentration in the exhaust stream. Avenal Power Center is not proposing to measure the SO₂ in the exhaust stream of the turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

Pursuant to Section 2.0, "All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein;" therefore, the requirements of this rule applies to the Avenal Power Center. However, there are no applicable requirements for a non-major HAPs source. As discussed above, Avenal Power Center is not a major HAP source; therefore, no actions are necessary to show compliance with this rule.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The following condition will be listed on the ATC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

ii. C-3953-12-0 (Boiler)

Based on past experiences with natural gas-fired boilers, no visible emissions are expected to be as dark as or darker than Ringelmann 1 (or 20% opacity). The following condition will be placed on the ATC to assure compliance with this rule.

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The following condition will be listed on the ATC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iv. C-3953-14-0 (Natural gas IC engine electrical generator)

The following condition will be listed on the ATC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, the following condition will be added to the permit to assure compliance with this rule.

- {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

A. California Health & Safety Code 41700 (Health Risk Analysis)

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the permit units for the power plant results in increases in emissions of HAPs.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit as shown in the table below:

Screen HRA Summary				
	Acute Hazard Index	Chronic Hazard Index	70 yr Cancer Risk	T-BACT Required?
C-3953-10-0 (Turbine #1)	0.0	0.0	0.02	No
C-3953-11-0 (Turbine #2)	0.0	0.0	0.02	No
C-3953-12-0 (Auxiliary Boiler)	0.0	0.0	0.01	No
C-3953-13-0 (Diesel-Fired IC Engine Fire Pump)	N/A*	N/A*	0.01	No
C-3953-14-0 (NG-Fired IC Engine Generator)	0.2	0.0	0.0	No

* Acute and Chronic Hazard Indices were not calculated since there is not a risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

i. C-3953-10-0 and -11-0 (Turbines)

$$PM \text{ Conc. (gr/scf)} = \frac{(PM \text{ emission rate}) \times (7000 \text{ gr/lb})}{\text{Exhaust Gas Flow}}$$

PM₁₀ emission rate = 11.78 lb/hr. Assuming 100% of PM is PM₁₀
 Exhaust Gas Flow = 1,071,653 dscfm

$$PM \text{ Conc. (gr/scf)} = \frac{(11.78 \text{ lb/hr}) \times (7,000 \text{ gr/lb})}{[(1,071,653 \text{ ft}^3/\text{min}) \times (60 \text{ min/hr})]}$$

PM Conc. = 0.0012 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all these turbines will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

ii. C-3953-12-0 (Boiler)

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

F-Factor for NG: 8,578 dscf/MMBtu at 60 °F
 PM10 Emission Factor: 0.005 lb-PM10/MMBtu
 Percentage of PM as PM10 in Exhaust: 100%
 Exhaust Oxygen (O₂) Concentration: 3%
 Excess Air Correction to F Factor = $\frac{20.9}{(20.9 - 3)} = 1.17$

$$GL = \left(\frac{0.005 \text{ lb-PM}}{\text{MMBtu}} \times \frac{7,000 \text{ grain}}{\text{lb-PM}} \right) / \left(\frac{8,578 \text{ ft}^3}{\text{MMBtu}} \times 1.17 \right)$$

$$GL = 0.0035 \text{ grain/dscf} < 0.1 \text{ grain/dscf}$$

Therefore, compliance with District Rule 4201 requirements is expected and a permit condition will be listed on the permit as follows:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iii. C-3953-13-0 (Diesel IC engine fire pump)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.059 \frac{\text{g-PM}_{10}}{\text{bhp-hr}} \times \frac{1 \text{ g-PM}}{0.96 \text{ g-PM}_{10}} \times \frac{1 \text{ bhp-hr}}{2,542.5 \text{ Btu}} \times \frac{10^6 \text{ Btu}}{9,051 \text{ dscf}} \times \frac{0.35 \text{ Btu out}}{1 \text{ Btu in}} \times \frac{15.43 \text{ grain}}{\text{g}} = 0.014 \frac{\text{grain-PM}}{\text{dscf}}$$

Since 0.014 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the ATC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iv. C-3953-14-0 (Natural gas IC engine electrical generator)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.034 \frac{g - PM_{10}}{bhp - hr} \times \frac{1g - PM}{0.96g - PM_{10}} \times \frac{1bhp - hr}{2,542.5 Btu} \times \frac{10^6 Btu}{9,051 dscf} \times \frac{0.35 Btu_{out}}{1 Btu_{in}} \times \frac{15.43 grain}{g} = 0.008 \frac{grain - PM}{dscf}$$

Since 0.008 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the ATC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to any of the permit units in this project, and no further discussion is required.

Rule 4301 Fuel Burning Equipment

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as “any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer”.

i. C-3953-10-0 and C-3953-11-0 (Turbines)

The CTG's primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTG's primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

ii. C-3953-12-0 (Boiler)

District Rule 4301 Limits			
Pollutant	NO₂	Total PM	SO₂
ATC #C-3953-12-0 (lb/hr)	0.41	0.19	0.10
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, continued compliance is expected.

iii. C-3953-13-0 (Diesel IC engine fire pump)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

iv. C-3953-14-0 (Natural gas IC engine electrical generator)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

Rule 4304 Tuning Procedure for Boilers, Steam Generators and Process Heaters

This rule is only applicable to unit C-3953-12-0.

Pursuant to District Rules 4305 and 4306, Section 6.3.1, the boiler is not required to tune since it follows a District approved Alternate Monitoring scheme where the applicable emission limits are periodically monitored. Therefore, the unit is not subject to this rule.

Rule 4305 Boilers Steam Generators and Process Heaters – Phase 2

This rule is only applicable to unit C-3953-12-0.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2*.

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3*.

Since emissions limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305.

Conclusion

Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

Rule 4306 Boilers Steam Generators and Process Heaters – Phase 3

This rule is only applicable to unit C-3953-12-0.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306.

Section 5.1, NO_x and CO Emissions Limits

Section 5.1.1 requires that except for units subject to Sections 5.2, NO_x and carbon monoxide (CO) emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

With a maximum heat input of 37.4 MMBtu/hr, the applicable emission limit category is listed in Section 5.1.1, Table 1, Category B, from District Rule 4306.

Rule 4306 Emissions Limits				
Category	Operated on gaseous fuel		Operated on liquid fuel	
	NO _x Limit	CO Limit	NO _x Limit	CO Limit
B. Units with a rated heat input greater than 20.0 MMBtu/hr, except for categories C, D, E, F, G, H, and I units	9 ppmv or 0.011 lb/MMBtu	400 ppmv	40 ppmv or 0.052 lb/MMBtu	400 ppmv

For the unit:

- the proposed NO_x emission factor is 9 ppmvd @ 3% O₂ (0.011 lb/MMBtu), and
- the proposed CO emission factor is 50 ppmvd @ 3% O₂ (0.037 lb/MMBtu).

Therefore, compliance with Section 5.1 of District Rule 4306 is expected.

A permit condition listing the emissions limits will be listed on permit as shown in the DEL section above.

Section 5.2, Low Use

The unit annual heat input will exceed the 9 billion Btu heat input per calendar year criteria limit addressed by this section. Since the unit is not subject to Section 5.2, the requirements of this section do not apply to the unit.

Section 5.3, Startup and Shutdown Provisions

Section 5.3 states that on and after the full compliance schedule specified in Section 7.1, the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.3.1 through 5.3.4.

According to boiler manufacturers, low NO_x burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emission factor following startup, the unit will be subject to the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 while in operation.

Section 5.4, Monitoring Provisions

Section 5.4.2 requires that permit units subject to District Rule 4306, Section 5.1 emissions limits shall either install and maintain Continuous Emission Monitoring (CEM) equipment for NO_x, CO and O₂, or install and maintain APCO-approved alternate monitoring.

The facility has proposed to install a CEMS system to satisfy the requirements of this section. The following condition will assure compliance with this section.

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NO_x, CO, and O₂. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

Since the unit is not subject to the requirements listed in Section 5.2.1 or 5.2.2, it is not subject to Section 5.4.3 requirements.

Since the unit is not subject to the requirements of category H (maximum annual heat input between 9 billion and 30 billion Btu/year) listed in Section 5.1.1, it is not subject to Section 5.4.4 requirements.

Section 5.5, Compliance Determination

Section 5.5.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the permit as follows:

- {2976} The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

Section 5.5.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following permit condition will be listed on the permit as follows:

- {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

Section 5.5.4 requires that for emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NO_x analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

Since the applicant does not use a portable analyzer to satisfy the monitoring requirements of District Rule 4306 the requirements of Section 5.5.4 do not apply.

Section 5.5.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

- {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

Section 6.1, Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.3 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

A permit condition will be listed on the permit as follows:

- {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

Section 6.1.2 requires that the operator of a unit subject to Section 5.2 shall record the amount of fuel use at least on a monthly basis. Since the unit is not subject to the requirements listed in Section 5.2, it is not subject to Section 6.1.2 requirements.

Section 6.1.3 requires that the operator of a unit subject to Section 5.2.1 or 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics have been performed. The unit is not subject to Section 6.1.3. Therefore, the requirements of this section do not apply to the unit.

Section 6.2, Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NO _x	ppmv	EPA Method 7E or ARB Method 100
NO _x	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O ₂	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

The following permit conditions will be listed on the permit as follows:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- {2977} NO_x emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]
- {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]
- {2979} Stack gas oxygen (O₂) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

Section 6.3, Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.1 and 5.2.3 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months.

The following permit conditions will be listed on the permit as follows:

- {3467} Source testing to measure NO_x and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]
- {3466} Source testing to measure NO_x and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]
- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Section 6.4, Emission Control Plan (ECP)

Section 6.4.1 requires that the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0 of District Rule 4306.

The proposed modified unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule and with periodic monitoring and source testing requirements. Therefore, this current application for the new proposed unit satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4306. No further discussion is required.

Section 7.0, Compliance Schedule

Section 7.0 indicates that an operator with multiple units at a stationary source shall comply with this rule in accordance with the schedule specified in Table 2, Section 7.1 of District Rule 4306.

The unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule, and periodic monitoring and source testing as required by District Rule 4306. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4306, are satisfied. No further discussion is required.

Conclusion

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule, see attached draft permit(s). Therefore, compliance with District Rule 4306 requirements is expected.

Rule 4351 Boilers Steam Generators and Process Heaters – Phase 1

This rule is only applicable to unit C-3953-12.

This rule applies to boilers, steam generators, and process heaters at NO_x Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. If applicable, the emission limits, monitoring provisions, and testing requirements of this rule are satisfied when the unit is operated in compliance with Rule 4306. Therefore, compliance with this rule is expected.

Rule 4701 Internal Combustion Engines – Phase 1

This rule is only applicable to units C-3953-13-0 and –14-0.

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, this diesel-fired emergency IC engine will comply with the requirements of District Rule 4702 and no further discussion is required.

Rule 4702 Internal Combustion Engines – Phase 2

This rule is only applicable to units C-3953-13-0 and –14-0.

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.

Pursuant to Section 4.2, except for the requirements of Sections 5.7 and 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following condition:

- 1) An emergency standby engine as defined in Section 3.0 of this rule, and provided that it is operated with a nonresettable elapsed operating time meter. In lieu of a nonresettable time meter, the owner of an emergency engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Section 3.15 defines an "Emergency Standby Engine" as an internal combustion engine which operates as a temporary replacement for primary mechanical or electrical power during an unscheduled outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the operator. An engine shall be considered to be an emergency standby engine if it is used only for the following purposes: (1) periodic maintenance, periodic readiness testing, or readiness testing during and after repair work; (2) unscheduled outages, or to supply power while maintenance is performed or repairs are made to the primary power supply; and (3) if it is limited to operate 100 hours or less per calendar year for non-emergency purposes. An engine shall not be considered to be an emergency standby engine if it is used: (1) to reduce the demand for electrical power when normal electrical power line service has not failed, or (2) to produce power for the utility electrical distribution system, or (3) in conjunction with a voluntary utility demand reduction program or interruptible power contract.

Therefore, unit C-3953-14-0, the emergency standby IC engine powering an electrical generator involved with this project will only have to meet the requirements of Sections 5.7 and 6.2.3 of this Rule.

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

- 1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
- 2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and
- 3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, unit C-3953-13-0, the emergency IC engine powering a firewater pump involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 5.7 of this Rule requires that the owner of an emergency standby engine shall comply with the requirements specified in Section 5.7.2 through Section 5.7.5 below:

- 1) Properly operate and maintain each engine as recommended by the engine manufacturer or emission control system supplier.
- 2) Monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier.
- 3) Install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO and is allowed by Permit-to-Operate or Stationary Equipment Registration condition. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the following conditions will be listed on ATC C-3953-14-0 to ensure compliance:

C-3953-14-0 (Natural Gas IC engine electrical generator)

- This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]
- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]
- An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]
- This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]
- This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO. Therefore, the following conditions will be listed on ATCs **C-3953-13-0** and **-14-0** to ensure compliance:

C-3953-13-0 (Diesel IC engine fire pump)

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]
- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]
- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

In addition, the following condition will be listed on the ATC to ensure compliance:

- {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]
- {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]
- {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

C-3953-14-0 (Natural Gas IC engine electrical generator)

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]
- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

Rule 4703 Stationary Gas Turbines

This rule is only applicable to units C-3953-10-0 and -11-0.

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install two 180 MW gas turbines. Therefore the requirements of this rule apply to the proposed turbines.

Section 5.1 – NO_x Emission Requirements:

Section 5.1.1 (Tier 1) of this rule limits the NO_x emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR). Since the proposed turbines will meet the more stringent Tier 2 emission requirements in Section 5.1.2, compliance with this section is assured.

Section 5.1.2 (Tier 2) of this rule limits the NO_x emissions from combined cycle, stationary gas turbine systems rated at greater than 10 MW to 5 ppmv @ 15% O₂ (Standard option) and 3 ppmv @ 15% O₂ (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbines will be limited to 2.0 ppmv @ 15% O₂ (based on a 1-hour average), therefore compliance with this section is expected. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) – 17.20 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O₂; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ – 11.78 lb/hr; or SO_x (as SO₂) – 6.65 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) - 13.55 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O₂; CO - 8.35 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ - 8.91 lb/hr; or SO_x (as SO₂) - 5.23 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 5.2 – CO Emission Requirements:

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbines (General Electric Frame 7) must be less than 25 ppmvd @ 15% O₂. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

Avenal Power Center is proposing a CO emission concentration limit of 2 ppmvd @ 15% O₂ and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbines will be operating the turbine in compliance with the CO emission requirements of this rule. The DEL conditions shown in the Section 5.1.2 compliance section will ensure continued compliance with the requirements of this section.

Section 5.3 – Startup and Shutdown Requirements:

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

Avenal Power Center is proposing to incorporate startup and shutdown provisions into the operating requirements for each of the proposed turbines. They have proposed that the duration of each startup or shutdown event will last no more than six hours per day. Since this proposed duration is longer than what is allowed in Section 5.3.1.1, the facility must meet the requirements of Section 5.3.3.2. Section 5.3.3.2 states that at a minimum, a justification for the increased duration shall include the following:

A clear identification of the control technologies or strategies to be utilized; and

The facility has identified the following control technologies:

- Dry low-NOx combustors in the turbines;
- Oxidation catalyst in the HRSGs;
- SCR in the HRSGs;
- Good combustion practices;
- Upon startup, the ammonia injection upstream of the SCR catalyst will be started as soon as the catalyst and ammonia injection system warm to their minimum operating temperatures specified by the SCR vendor.

A description of what physical conditions prevail during the period that prevent the controls from being effective; and

The combined-cycle equipment startup duration depends on how fast the thick steel walls of the common steam turbine can be warmed to operating temperature without generating stress cracks. Steam developed in the HRSG from the heated turbine exhaust is admitted into the steam turbine at a controlled temperature to heat it as rapidly as possible without causing stress cracking. The steam temperature is controlled by limiting the load on the gas turbine. The allowable rate of temperature increase at the steam turbine is the limiting factor determining how quickly the gas turbines can achieve higher loads. This, in turn, limits how quickly the gas turbine combustors can achieve the lowest emitting operating mode, and this latter step is necessary for the units to be able to comply with the limits of Rule 4703.

A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a minimum of four hours is required for the unit to come into compliance with the limits of Rule 4703. Depending on the temperature of the steam turbine at the time the start is initiated, shorter durations may be possible.

A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity; and

The facility has provided the District with a detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity.

A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and

The startup duration depends on the allowable ramp rate of the steam temperature to the steam turbine, which depends on the acceptable rate of increase of the metal temperature of the HRH and HP bowls at the steam turbine inlets. The maximum steam temperature is set by applying an allowable differential above the metal temperature. The differential is determined by the steam turbine supplier, and is imposed by the supplier's control system to avoid damage to the steam turbine from thermal stress. The control system limits gas turbine load to control the steam temperature. Manual override of the gas turbine load limit by the operator reduces the life expectancy of the steam turbine.

In addition, the time prior to initiation of ammonia flow to the SCR system depends on the temperature of the SCR catalyst. The catalyst bed is warmed by the exhaust flow from the gas turbine. The total mass of metal and water in the HRSG tubes, piping, and drums removes heat from the gas turbine exhaust as it warms. This extends the time required to heat the SCR catalyst to the minimum temperature at which ammonia may be injected upstream of the catalyst bed to begin reducing NO_x to N₂. The steam turbine and SCR catalyst temperatures are all monitored by the plant control system, and the turbine ramp rate and SCR initiation sequence are governed by the equipment/system manufacturer's recommended procedures.

The basis for the requested additional duration.

The startup curve in Attachment I and the description of activities above demonstrate that the minimum time required for a cold startup of the plant as currently configured is approximately 4 hours. This startup time is contingent upon all of the activities being performed in time to support subsequent activities. Any delay in preparation of the supporting systems will result in a corresponding delay in startup and/or loading of the gas turbines. To be confident that the startup time allowed is adequate and will not be exceeded, one hour is added to the above startup time to account for possible delays.

Since the facility has demonstrated compliance and provided all the information asked for in Section 5.3.3.2, the proposed increase in startup and shutdown emissions is compliant with District Rule 4703. The following conditions will ensure continued compliance with the requirements of this section:

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_x (as NO₂) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM₁₀ – 11.78 lb/hr; SO_x (as SO₂) – 6.652 lb/hr; or NH₃ – 32.13 lb/hr. [District Rules 2201 and 4703]

- Startup shall be defined as 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. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]
- The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]
- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 - Monitoring and Recordkeeping:

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_x and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, the applicant operates a Continuous Emissions Monitoring System (CEMS) that monitors the NO_x and oxygen content of the turbine exhaust. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_x, CO and O₂ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_x control devices. Each of the proposed turbines will be equipped with an SCR system that is designed to control NO_x emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_x emissions. The proposed turbines have not been installed. Therefore, they were not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. Avenal Power Center will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_x output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_x available or when the continuous emissions monitoring system is not operating properly. Avenal Power Center will be required, by permit condition, to submit information correlating the NO_x control system operating parameters to the associated measured NO_x output. Therefore, the proposed turbines will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The permittee shall submit to the District information correlating the NO_x control system operating parameters to the associated measured NO_x output. The information must be sufficient to allow the District to determine compliance with the NO_x emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. Avenal Power Center will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]
- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NO_x mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, Avenal Power Center will be required, by permit condition, to maintain records of the date, time and duration of each startup and shutdown. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule.

Sections 6.3 and 6.4 - Compliance Testing:

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_x and CO concentrations. The turbines operated by Avenal Power Center are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas NO_x and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NO_x, CO and VOC emission rates (lb/hr and ppmvd @ 15% O₂), NH₃ emission rate (ppmvd @ 15% O₂) and PM₁₀ emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbines will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner both on and off. The following condition will ensure continued compliance with the requirements of this section:

- Compliance with the NO_x and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

Section 6.4 states that the facility must demonstrate compliance annually with the NO_x and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.
- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NO_x - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM₁₀ - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O₂ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

Rule 4801 Sulfur Compounds

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO₂ on a dry basis averaged over 15 consecutive minutes:

i. C-3953-10-0 and -11-0 (Turbines)

The sulfur of the natural gas fuel is 1.0 gr/100 dscf.

The ratio of the volume of the SO_x exhaust to the entire exhaust for one MMBtu of fuel combusted is:

$$\text{Volume of SO}_x: \quad V = \frac{n \cdot R \cdot T}{P}$$

Where:

- n = number of moles of SO_x produced per MMBtu of fuel.
- Weight of SO_x as SO₂ is 64 lb/(lb-mol)
- $n = \frac{0.00282 \text{ lb}}{\text{MMBtu}} \times \frac{1 \text{ (lb-mol)}}{64 \text{ lb}} = 0.000045 \text{ (lb-mol)}$
- $R = \frac{0.7302 \text{ ft}^3 \cdot \text{atm}}{\text{(lb-mol)}^\circ\text{R}}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_x per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$
$$V = \frac{0.000045 \text{ (lb-mol)} \cdot \frac{0.7302 \text{ ft}^3 \cdot \text{atm}}{\text{(lb-mol)}^\circ\text{R}} \cdot 500^\circ\text{R}}{1 \text{ atm}}$$

$$V = 0.016 \text{ ft}^3$$

Since the total volume of exhaust per MMBtu is 8,578 scf, the ratio of SO_x volume to exhaust volume is

$$= \frac{0.016}{8,578} = 0.0000019 = 1.9 \text{ ppmv} = 0.00019\% \text{ by volume}$$

1.9 ppmv ≤ 2000 ppmv, therefore the turbines, the boiler, and the gas engine are expected to comply with Rule 4801.

ii. C-3953-12-0 (Boiler)

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

$$\text{Volume SO}_2 = \frac{nRT}{P}$$

With:

N = moles SO₂

T (Standard Temperature) = 60°F = 520°R

P (Standard Pressure) = 14.7 psi

R (Universal Gas Constant) = $\frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}}$

$$\frac{0.00282 \text{ lb} - \text{SO}_x}{\text{MMBtu}} \times \frac{\text{MMBtu}}{8,578 \text{ dscf}} \times \frac{1 \text{ lb} \cdot \text{mol}}{64 \text{ lb}} \times \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}} \times \frac{520^\circ\text{R}}{14.7 \text{ psi}} \times \frac{1,000,000 \cdot \text{parts}}{\text{million}} = 1.97 \frac{\text{parts}}{\text{million}}$$

$$\text{SulfurConcentration} = 1.97 \frac{\text{parts}}{\text{million}} < 2,000 \text{ ppmv (or 0.2\%)}$$

Therefore, compliance with District Rule 4801 requirements is expected.

iii. C-3953-13-0 (Diesel IC engine powering a fire water pump)

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

$$\text{Volume SO}_2 = (n \times R \times T) \div P$$

n = moles SO₂

T (standard temperature) = 60 °F or 520 °R

R (universal gas constant) = $\frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}}$

$$\frac{0.000015 \text{ lb} - \text{S}}{\text{lb} - \text{fuel}} \times \frac{7.1 \text{ lb}}{\text{gal}} \times \frac{64 \text{ lb} - \text{SO}_2}{32 \text{ lb} - \text{S}} \times \frac{1 \text{ MMBtu}}{9,051 \text{ scf}} \times \frac{1 \text{ gal}}{0.137 \text{ MMBtu}} \times \frac{\text{lb} - \text{mol}}{64 \text{ lb} - \text{SO}_2} \times \frac{10.73 \text{ psi} - \text{ft}^3}{\text{lb} - \text{mol} - ^\circ\text{R}} \times \frac{520^\circ\text{R}}{14.7 \text{ psi}} \times 1,000,000 = 1.0 \text{ ppmv}$$

Since 1.0 ppmv is \leq 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-0 (Natural gas IC engine powering an electrical generator)

$$\text{Volume SO}_2 = (n \times R \times T) \div P$$

n = moles SO₂

T (standard temperature) = 60 °F or 520 °R

$$R (\text{universal gas constant}) = \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot \text{°R}}$$

$$2.85 \frac{\text{lb} - S}{\text{MMscf} - \text{gas}} \times \frac{1 \text{ scf} - \text{gas}}{1,000 \text{ Btu}} \times \frac{1 \text{ MMBtu}}{8,578 \text{ scf}} \times \frac{1 \text{ lb} - \text{mol}}{64 \text{ lb} - S} \times \frac{10.73 \text{ psi} - \text{ft}^3}{\text{lb} - \text{mol} - \text{°R}} \times \frac{520 \text{ °R}}{14.7 \text{ psi}} \times 1,000,000 = 1.97 \text{ ppmv}$$

Since 1.97 ppmv is \leq 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

District Rule 8011 General Requirements

District Rule 8021 Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities

District Rule 8031 Bulk Materials

District Rule 8041 Carryout And Trackout

District Rule 8051 Open Areas

District Rule 8061 Paved And Unpaved Roads

District Rule 8071 Unpaved Vehicle/Equipment Traffic Areas

District Rule 8081 Agricultural Sources

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]
- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]
- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]
- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]
- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]
- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]
- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]
- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]
- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

California Environmental Quality Act (CEQA)

The District determined that the California Energy Commission (CEC) is the public agency having principal responsibility for approving the project, therefore establishing the CEC as the Lead Agency (CEQA Guidelines §15051(b)). The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's significance thresholds for criteria pollutants. The District has determined that no additional findings are required (CEQA Guidelines §15096(h)).

California Health & Safety Code, Section 42301.6 (School Notice)

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Health & Safety Code, Section 44300 (Air Toxic “Hot Spots”)

Section 44300 of the California Health and Safety Code requires submittal of an air toxics “Hot Spot” information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.
2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.
3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment (Required by Title 17 CCR, Section 93115 for New Emergency Diesel IC Engines)

The requirements of this section are only applicable to C-3953-13-0.

Particulate Matter and VOC + NO_x, and CO Exhaust Emissions Standards:

This regulation stipulates that off-road compression-ignition engines shall not exceed the following applicable emissions standards.

Title 13 CCR, Section 2423 lists a diesel particulate emission standard of 0.15 g/bhp-hr (with 1.341 bhp/kW, equivalent to 0.20 g/kW-hr) for 2003 - 2005 model year engines with maximum power ratings of 174.3 - 301.6 bhp (equivalent to 130 - 225 kW). The PM standards given in Title 13 CCR, Section 2423 are less stringent than the PM standards given in Title 17 CCR, Section 93115 (ATCM), thus the ATCM standards are the required standards and will be discussed in the following section.

Title 17 CCR, Section 93115, (e)(2)(A)(3)(b) stipulates that new stationary emergency diesel-fueled CI engines (> 50 bhp) must meet the VOC + NO_x, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13 CCR, Section 2423) or the Tier 1 standards for an off-road engine if no standards have been established for an off-road engine of the same model year and maximum rated power.

In addition, Title 17 CCR, Section 93115, (e)(2)(A)(4)(a)(II) allows new direct-drive emergency fire pump engines to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423) until three years after the date the Tier 3 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 3 emission standards, until three years after the date the Tier 4 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 4 emission standards; and not operate more than the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition, which is incorporated herein by reference. In addition, this subsection does not limit engine operation for emergency use and for emission testing to show compliance with (e)(2)(A)4. For this project the proposed emergency diesel IC engine will be used to power a firewater pump and is therefore allowed to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines three years after the applicable dates specified. This additional three-year allowance is reflected in the following table.

The engine involved with this project is a certified 2007 model engine. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the 288 bhp Cummins Model #CFP83-F40 diesel-fired emergency IC engine as given by the manufacturer (for NO_x + VOC and PM emissions).

Avenal Power Center, LLC (08-AFC-01)
SJVACPD Determination of Compliance, C-1080386

Requirements of Title 13 CCR, Section 2423							
Source	Maximum Rated Power	Model Year	NO _x	VOC	NO _x + VOC	CO	PM
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	1996-2002 (Tier 1)	6.9 g/bhp-hr (9.2 g/kW-hr)	1.0 g/bhp-hr (1.3 g/kW-hr)	--	8.5 g/bhp-hr (11.4 g/kW-hr)	0.40 g/bhp-hr (0.54 g/kW-hr)
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	2003-2005, extended to 2008 (Tier 2)	--	--	4.9 g/bhp-hr (6.6 g/kW-hr)	2.6 g/bhp-hr (3.5 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	2006 and later, extended to 2009 (Tier 3)	--	--	3.0 g/bhp-hr (4.0 g/kW-hr)	2.6 g/bhp-hr (3.5 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Cummins, Model #CFP83-F40	288 bhp	2007	--	--	3.8g/bhp-hr (5.1 g/kW-hr)	0.447 g/bhp-hr (0.60 g/kW-hr)	0.059 g/bhp-hr (0.079 g/kW-hr)
Meets Standard?			N/A	N/A	Yes	Yes	Yes

As presented in the table above, the proposed engine will satisfy the requirements of this section and compliance is expected.

The engine manufacturer's data and/or CARB/EPA engine certification for this engine lists a NO_x emissions factor of 3.4 g/bhp-hr, a VOC emissions factor of 0.38 g/bhp-hr, a NO_x + VOC emission factor of 3.8 g/bhp-hr, a CO emission factor of 0.447 g/bhp-hr, and a PM₁₀ emissions factor of 0.059 g/bhp-hr, all of which satisfy the requirements of 13 CCR, Section 2423. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NO_x/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]
- Emissions from this IC engine shall not exceed 0.059 g-PM₁₀/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

Right of the District to Establish More Stringent Standards:

This regulation also stipulates that the District:

1. May establish more stringent diesel PM, NO_x + VOC, VOC, NO_x, and CO emission rate standards; and
2. May establish more stringent limits on hours of maintenance and testing on a site-specific basis; and
3. Shall determine an appropriate limit on the number of hours of operation for demonstrating compliance with other District rules and initial start-up testing

The District has not established more stringent standards at this time. Therefore, the standards previously established in this Section will be utilized.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

The requirements of this section are only applicable to C-3953-13-0.

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a PM₁₀ emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

- a. Emergency use hours of operation;
- b. Maintenance and testing hours of operation;
- c. Hours of operation for emission testing;
- d. Initial start-up hours; and
- e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
- f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
- g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:
 - I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
 - II. Amount of fuel purchased;
 - III. Date when the fuel was purchased;
 - IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
 - V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]
- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Final Determination of Compliance for the facility subject to the conditions presented in Attachment A.

X. BILLING INFORMATION:

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-3953-10-0	3020-08B-B	180,000 kW	\$12,229.00
C-3953-11-0	3020-08B-B	180,000 kW	\$12,229.00
C-3953-12-0	3020-02-H	37.4 MMBtu/hr boiler	\$953.00
C-3953-13-0	3020-10-C	288 bhp IC engine	\$222.00
C-3953-14-0	3020-10-E	860 bhp IC engine	\$557.00

ATTACHMENT A
FDOC CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-3953-10-0:

180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_x COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]
2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]
3. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide NO_x (as NO₂) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]
4. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]
5. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide PM₁₀ emission reduction credits for the following quantities of emissions: 1st quarter – 33,085 lb; 2nd quarter – 33,085 lb; 3rd quarter – 33,085 lb; and 4th quarter – 33,085 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SO_x ERC's may be used to offset PM₁₀ increases at an interpollutant ratio of 1.0 lb-SO_x : 1.0 lb-PM₁₀. [District Rule 2201]
6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]
7. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
9. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
10. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]
11. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]
12. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_x, CO and O₂ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]
13. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]
14. The NO_x, CO and O₂ CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]
15. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]
16. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_x, CO and O₂ as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

17. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]
18. Results of the CEM system shall be averaged over a one hour period for NO_x emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]
19. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]
20. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]
21. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]
22. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]
23. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_x emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]
24. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]
25. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

26. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) – 17.20 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O₂; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ – 11.78 lb/hr; or SO_x (as SO₂) – 6.65 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]
27. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) - 13.55 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O₂; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ – 8.91 lb/hr; or SO_x (as SO₂) – 5.23 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]
28. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_x (as NO₂) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM₁₀ – 11.78 lb/hr; SO_x (as SO₂) – 6.652 lb/hr; or NH₃ – 32.13 lb/hr. [District Rules 2201 and 4703]
29. Daily emissions from the CTG shall not exceed the following limits: NO_x (as NO₂) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM₁₀ – 282.7 lb/day; SO_x (as SO₂) – 159.6 lb/day, or NH₃ – 771.1 lb/day. [District Rule 2201]
30. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NO_x (as NO₂) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM₁₀ – 282.7 lb/day; SO_x (as SO₂) – 159.6 lb/day, or NH₃ – 771.1 lb/day. [District Rule 2201]
31. The ammonia (NH₃) emissions shall not exceed 10 ppmvd @ 15% O₂ over a 24 hour rolling average. [District Rule 2201]
32. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]
33. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_x (as NO₂) – 143,951 lb/year; CO – 601,810 lb/year; VOC – 34,489 lb/year; PM₁₀ – 80,656 lb/year; or SO_x (as SO₂) – 16,694 lb/year; or NH₃ – 208,708 lb/year. [District Rule 2201]
34. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]
35. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

36. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]
37. Startup shall be defined as 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. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]
38. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]
39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_x, CO, and O₂ analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]
40. Source testing to measure startup NO_x, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]
41. Source testing (with and without duct burner firing) to measure the NO_x, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O₂) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]
42. Source testing (with and without duct burner firing) to measure the PM₁₀ emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]
43. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

44. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]
45. Source testing to determine compliance with the NO_x, CO and VOC emission rates (lb/hr and ppmvd @ 15% O₂), NH₃ emission rate (ppmvd @ 15% O₂) and PM₁₀ emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]
46. Compliance with the NO_x and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]
47. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
48. The following test methods shall be used: NO_x - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM₁₀ - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O₂ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]
49. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]
50. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_x concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_x or O₂ (or both). [40 CFR 60.4380(b)(1)]
51. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]
52. The permittee shall submit to the District information correlating the NO_x control system operating parameters to the associated measured NO_x output. The information must be

sufficient to allow the District to determine compliance with the NO_x emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

53. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]
54. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]
55. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NO_x mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]
56. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]
57. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]
58. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]
59. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]
60. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]
61. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]
62. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle

travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

63. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]
64. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]
65. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]
66. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-3953-11-0:

180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_x COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]
2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]
3. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide NO_x (as NO₂) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]
4. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]
5. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide PM₁₀ emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SO_x ERC's may be used to offset PM₁₀ increases at an interpollutant ratio of 1.0 lb-SO_x : 1.0 lb-PM₁₀. [District Rule 2201]
6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]
7. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
9. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
10. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]
11. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]
12. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_x, CO and O₂ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]
13. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]
14. The NO_x, CO and O₂ CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]
15. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]
16. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_x, CO and O₂ as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

17. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]
18. Results of the CEM system shall be averaged over a one hour period for NO_x emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]
19. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]
20. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]
21. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]
22. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]
23. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_x emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]
24. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]
25. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

26. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) – 17.20 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O₂; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ – 11.78 lb/hr; or SO_x (as SO₂) – 6.65 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]
27. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NO_x (as NO₂) - 13.55 lb/hr and 2.0 ppmvd @ 15% O₂; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O₂; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O₂; PM₁₀ – 8.91 lb/hr; or SO_x (as SO₂) – 5.23 lb/hr. NO_x (as NO₂) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]
28. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_x (as NO₂) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM₁₀ – 11.78 lb/hr; SO_x (as SO₂) – 6.652 lb/hr; or NH₃ – 32.13 lb/hr. [District Rules 2201 and 4703]
29. Daily emissions from the CTG shall not exceed the following limits: NO_x (as NO₂) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM₁₀ – 282.7 lb/day; SO_x (as SO₂) – 159.6 lb/day, or NH₃ – 771.1 lb/day. [District Rule 2201]
30. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NO_x (as NO₂) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM₁₀ – 282.7 lb/day; SO_x (as SO₂) – 159.6 lb/day, or NH₃ – 771.1 lb/day. [District Rule 2201]
31. The ammonia (NH₃) emissions shall not exceed 10 ppmvd @ 15% O₂ over a 24 hour rolling average. [District Rule 2201]
32. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]
33. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_x (as NO₂) – 143,951 lb/year; CO – 601,810 lb/year; VOC – 34,489 lb/year; PM₁₀ – 80,656 lb/year; or SO_x (as SO₂) – 16,694 lb/year; or NH₃ – 208,708 lb/year. [District Rule 2201]
34. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]
35. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

36. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]
37. Startup shall be defined as 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. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]
38. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]
39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_x, CO, and O₂ analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]
40. Source testing to measure startup NO_x, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]
41. Source testing (with and without duct burner firing) to measure the NO_x, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O₂) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]
42. Source testing (with and without duct burner firing) to measure the PM₁₀ emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]
43. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].
44. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a

- valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]
45. Source testing to determine compliance with the NO_x, CO and VOC emission rates (lb/hr and ppmvd @ 15% O₂), NH₃ emission rate (ppmvd @ 15% O₂) and PM₁₀ emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]
46. Compliance with the NO_x and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]
47. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
48. The following test methods shall be used: NO_x - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM₁₀ - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O₂ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]
49. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]
50. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_x concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_x or O₂ (or both). [40 CFR 60.4380(b)(1)]
51. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]
52. The permittee shall submit to the District information correlating the NO_x control system operating parameters to the associated measured NO_x output. The information must be sufficient to allow the District to determine compliance with the NO_x emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

53. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]
54. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]
55. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]
56. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

EQUIPMENT DESCRIPTION, UNIT C-3953-12-0:

37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]
2. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide NO_x (as NO₂) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]
3. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]
4. Prior to initial operation of C-3953-10-0, C-3953-11-0, and C-3953-12-0, permittee shall provide PM₁₀ emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SO_x ERC's may be used to offset PM₁₀ increases at an interpollutant ratio of 1.0 lb-SO_x : 1.0 lb-PM₁₀. [District Rule 2201]
5. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]
6. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]
7. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]
8. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

9. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]
10. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
11. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
12. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
13. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
14. {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]
15. Emission rates from this unit shall not exceed any of the following limits: NO_x (as NO₂) - 9.0 ppmvd @ 3% O₂ or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O₂; CO - 50.0 ppmvd @ 3% O₂ or 0.037 lb/MMBtu; PM₁₀ - 0.005 lb/MMBtu; or SO_x (as SO₂) - 0.00285 lb/MMBtu. [District Rules 2201, 4305, and 4306]
16. {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]
17. {3467} Source testing to measure NO_x and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]
18. {3466} Source testing to measure NO_x and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]
19. {2976} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

20. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
21. {2977} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]
22. {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]
23. {2979} Stack gas oxygen (O₂) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]
24. {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]
25. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
26. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]
27. Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]
28. {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]
29. {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NO_x, CO, and O₂. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]
27. {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]
28. {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

29. {1835} The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]
30. {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]
31. {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]
32. {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]
33. {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

EQUIPMENT DESCRIPTION, UNIT C-3953-13-0:

**288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE
POWERING A FIRE PUMP**

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]
6. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]
7. {3403} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]
8. Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]
9. Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]
10. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]
11. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

12. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

13. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

EQUIPMENT DESCRIPTION, UNIT C-3953-14-0:

860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]
2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]
7. {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]
8. {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]
9. Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]
10. {3405} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
11. {3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]
12. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

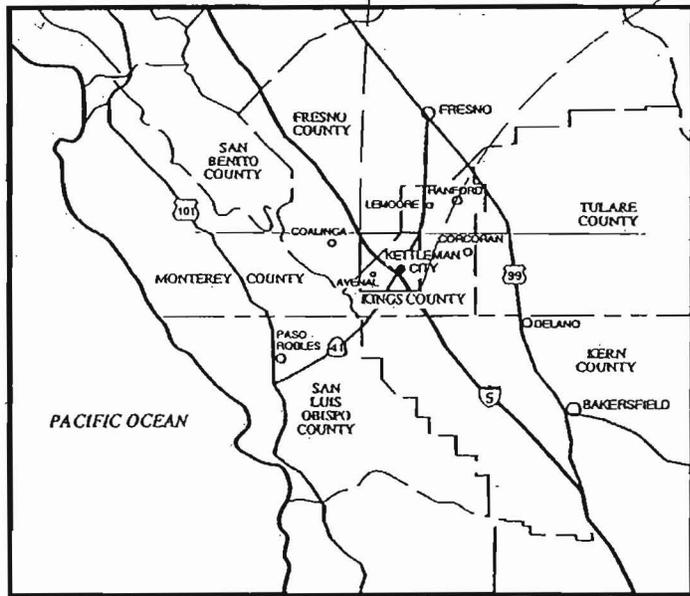
13. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]
14. {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]
15. {3496} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]
16. {3497} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

ATTACHMENT B

Project Location and Site Plan



VICINITY MAP
NOT TO SCALE



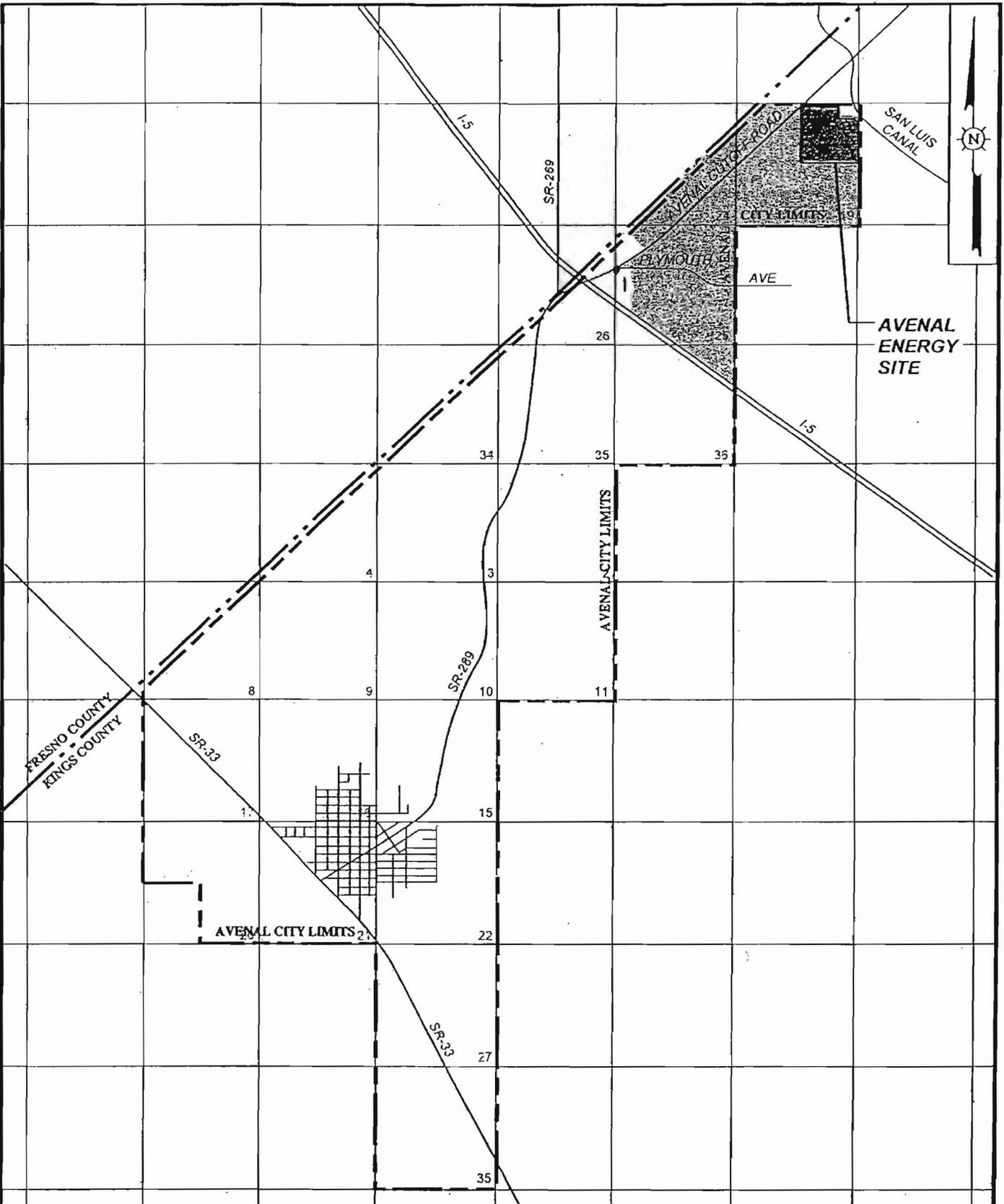
REGIONAL MAP



REGIONAL LOCATION MAP

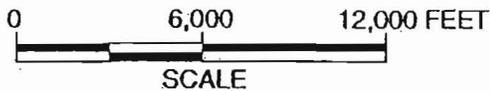
FEDERAL ENERGY AVENAL, LLC

AVENAL ENERGY	FIGURE 2.0-1
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LEGEND

 INDUSTRIAL ZONE (CITY OF AVENAL GENERAL PLAN AND ZONING ORDINANCE)



REFERENCE: CITY OF AVENAL GENERAL PLAN.

1 36.074 -120.093

AV SITE LOCATION

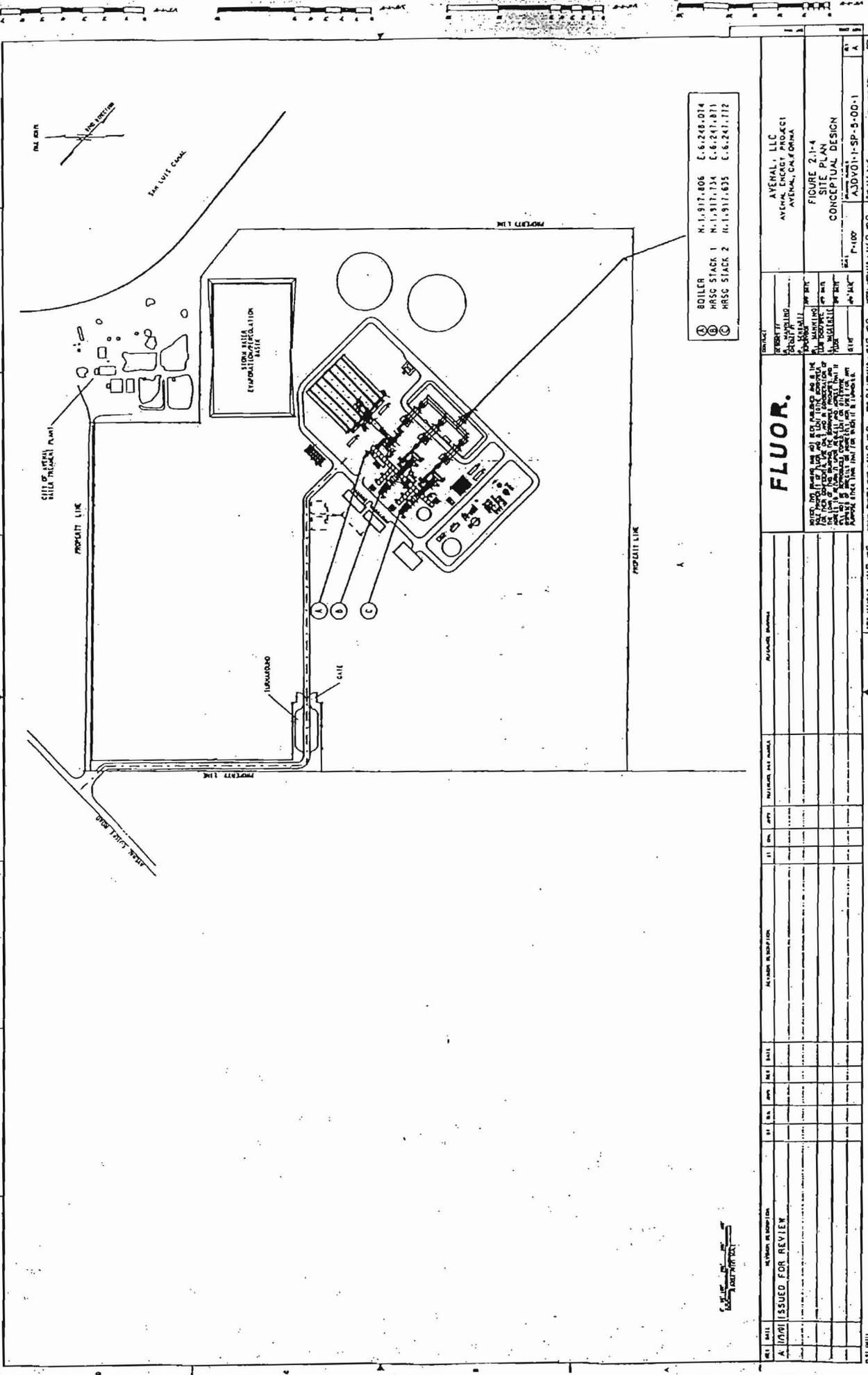
② Rd crosses horizon near development

36.109 -120.0486

FEDERAL POWER AVENAL, LLC

AVENAL ENERGY

FIGURE 2.0-2



- ① BOILER N-1-917-806 E-6-248-014
- ② HRSG STACK 1 N-1-917-734 E-6-247-871
- ③ HRSG STACK 2 N-1-917-635 E-6-247-772

FLUOR.

AYERAL, LLC
 AYERAL ENERGY PROJECT
 AYERAL, CALIFORNIA

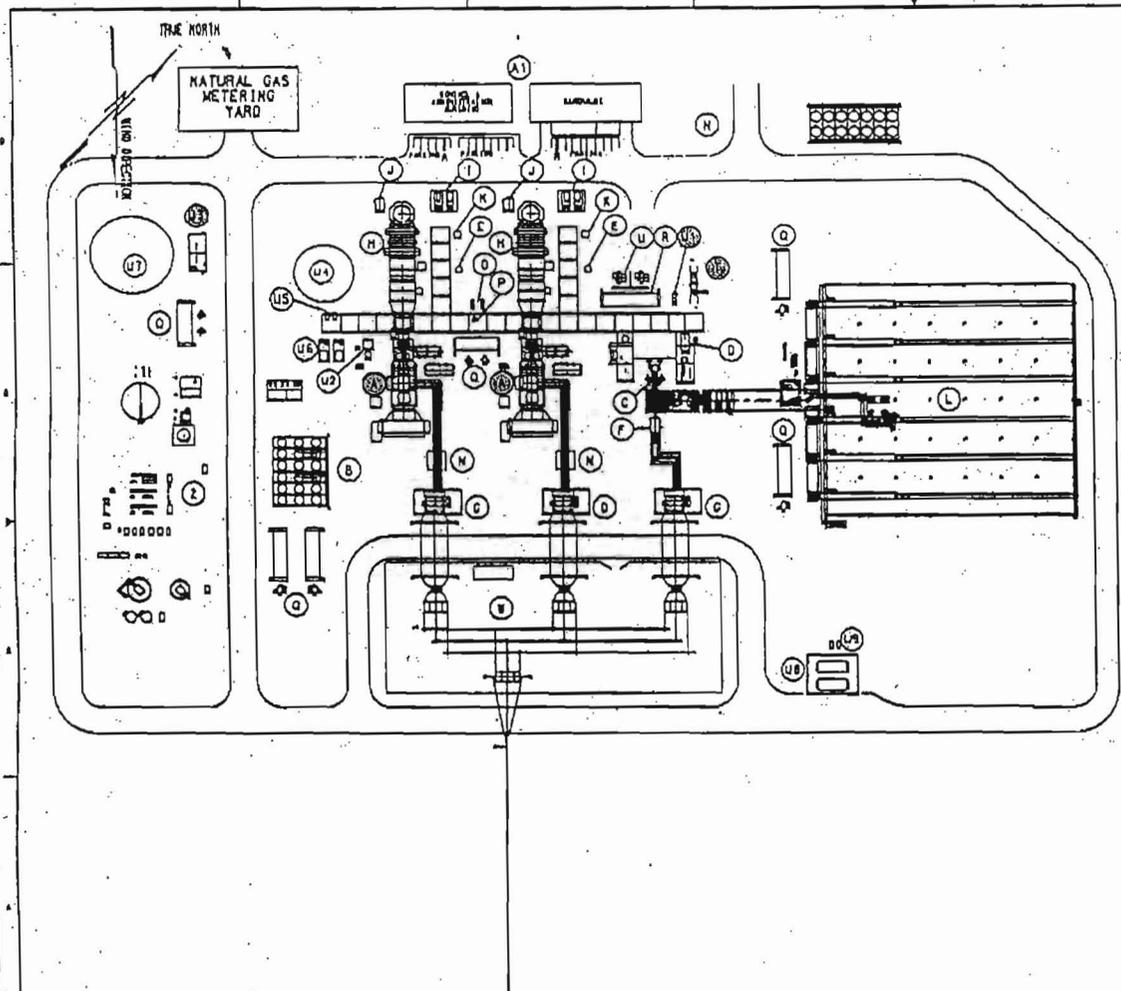
FIGURE 2.11-4
 SITE PLAN
 CONCEPTUAL DESIGN

SCALE: 1"=100'

DATE: 03/11/2011

PROJECT NO: A3J1011-SP-3-001-1

NO.	DATE	BY	CHKD.	APPV.	REVISION DESCRIPTION	APPROVED SIGNATURE	CONTACT
1							
A (000) ISSUED FOR REVIEW							PROJECT NO: A3J1011-SP-3-001-1 SHEET NO: 01 OF 01 SCALE: 1"=100' DATE: 03/11/2011



MAJOR EQUIPMENT LIST

- A GAS TURBINE GENERATOR
- B INLET AIR CHILLERS
- C STEAM TURBINE
- D STO LUBE OIL SAID
- E HRSG BLOW DOWN DRUM
- F STO GENERATION
- G MAIN TRANSFORMERS
- H HEAT RECOVERY STEAM GENERATOR
- I HP/IP BOILER FEED WATER PUMPS
- J CONTINUOUS EMISSIONS MONITORING SYSTEM
- K HRSG BLOWDOWN SUMP
- L AIR COOLED CONDENSER
- M GENERATOR BREAKERS
- N CLOSED COOLING WATER AIR COOLER
- O CIRCULATING COOLING WATER PUMPS
- P CLOSED COOLING WATER EXPANSION TANK
- Q POWER DISTRIBUTION CENTER (480 V)
- R POWER DISTRIBUTION CENTER (14160 V)
- S
- T AUXILIARY BOILER
- U UNIT AUXILIARY TRANSFORMER
- V
- W SWITCHYARD
- X RAW WATER SOFTENER CLARIFIERS (RWSC)
- Y RWSC FILTER PRESS
- Z ZERO LIQUID DISCHARGE FACILITY (ZLDF)

- A1 SEPTIC TANK & LEACH FIELD (IMMEDIATELY NW)
- A2 STORM WATER EVAPORATION/PERCOLATION BASIN

UTILITIES

- U1 STANDBY DIESEL GENERATOR
- U2 OIL/WATER SEPARATOR
- U3 FIREWATER PUMP HOUSE
- U4 DEMINERALIZED WATER STORAGE TANK
- U5 DEMINERALIZED WATER PUMPS
- U6 PLANT/INSTRUMENT AIR COMPRESSORS
- U7 RAW WATER/FIREWATER STORAGE TANKS
- U8 AMMONIA STORAGE TANKS
- U9 AMMONIA TRANSFER PUMPS

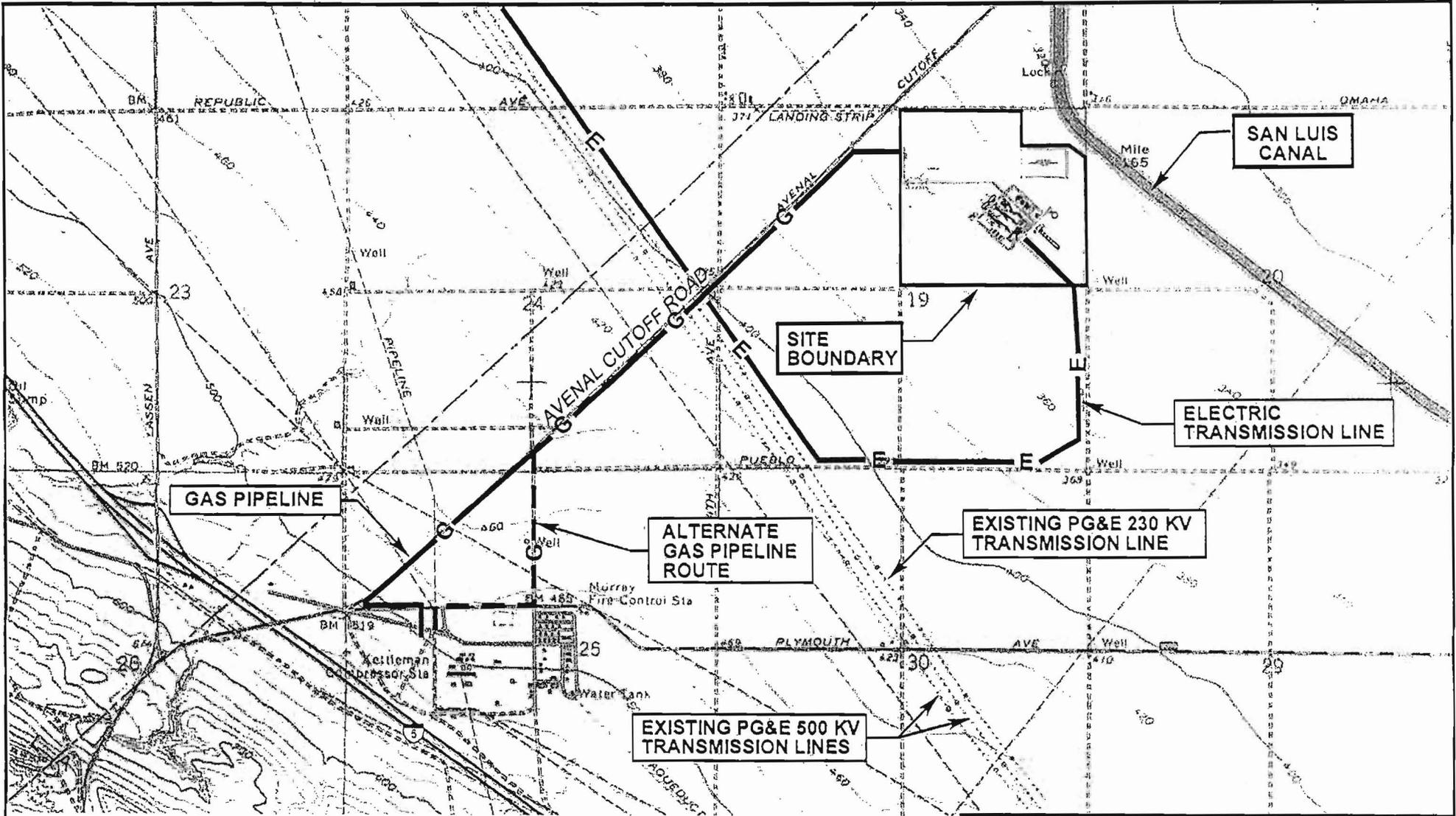


REV	DATE	REVISION DESCRIPTION	BY	CHK	APP	DATE	APPROVAL DESCRIPTION	BY	CHK	APP	DATE	APPROVAL DESCRIPTION
A	1/11/11	ISSUED FOR REVIEW										

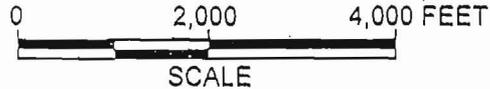
FLUOR.

NOTE: THIS PLAN IS THE PROPERTY OF FLUOR CORP. AND IS NOT TO BE REPRODUCED, COPIED, OR TRANSMITTED IN ANY FORM OR BY ANY MEANS, ELECTRONIC OR MECHANICAL, INCLUDING PHOTOCOPYING, RECORDING, OR BY ANY INFORMATION STORAGE AND RETRIEVAL SYSTEM. WITHOUT THE WRITTEN PERMISSION OF FLUOR CORP.

PROJECT NO. A330Y01-1-PP-0-00-1	SHEET NO. 1 OF 1	SCALE 1" = 25'	DATE 1/11/11
AVERA, LLC AVERA ENERGY PROJECT AVERA, CALIFORNIA		FIGURE 2.3-3 PLOT PLAN CONCEPTUAL DESIGN	



REFERENCE:
 U.S.G.S 7.5 MINUTE TOPOGRAPHIC SERIES MAP
 OF LA CIMA, CALIFORNIA, DATED 1978.



NATURAL GAS AND ELECTRICAL
 INTERCONNECTION ROUTES

FEDERAL POWER AVENAL LLC

AVENAL ENERGY

FIGURE 2.1-1A

ATTACHMENT C

CTG Commissioning Period Emissions Data

The maximum heat input rates (fuel consumption rates) for the gas turbines, duct burners, and auxiliary boiler are shown in Table 6.2-22.

TABLE 6.2-22
MAXIMUM FACILITY FUEL USE, MMBTU (HHV)

Period	Gas Turbines and Duct Burners (each ^a)	Auxiliary Boiler	Total Fuel Use (all Units)
Per Hour	2,356.5	37.4	4,750
Per Day	56,555 ^b	449 ^c	113,111 ^d
Per Year	16,176,000 ^e	46,650 ^f	32,353,000 ^g

Notes:

^a Each of two trains.

^b Based on 24 hours per day of duct firing.

^c Based on a startup day, during which the auxiliary boiler would be used 12 hours.

^d The maximum facility fuel use day, during which the turbines run 24 hours with duct firing, has no use of the auxiliary boiler (i.e., no startup).

^e Based on maximum fuel use of 7,960 hours per year without duct firing, and 800 hours per year with duct firing, per turbine.

^f Based on 1,248 hours of operation per year.

^g Based on baseload scenario (see Footnote d) that includes no operation of the auxiliary boiler.

CTG Emissions During Startup and Shutdown

Maximum emission rates expected to occur during a startup or shutdown are shown in Table 6.2-23. PM₁₀ and SO₂ emissions have not been included in this table because emissions of these pollutants depend on fuel flow, which will be lower during a startup period than during baseload facility operation.

TABLE 6.2-23
FACILITY STARTUP/SHUTDOWN EMISSION RATES^a

	NOx	CO	VOC
Startup/Shutdown, lb/hour, average	80	900	16
Startup/Shutdown, lb/ start / _{hour} maximum	160	1,000	16

^a Estimated based on vendor data and source test data. See Appendix 6.2-1, Table 6.2-1.6 and -1.7.

The analysis of maximum facility emissions of each criteria pollutant was based on the turbine/HRSG and auxiliary boiler emission factors shown in Tables 6.2-19, 6.2-20, and 6.2-21; the startup emission rates shown in Table 6.2-23; the three operating scenarios described above, and the ambient conditions that result in the highest emission rates. The maximum annual, daily, and hourly emissions of each criteria pollutant for the Project are shown in Table 6.2-24 and are based on the following operating conditions and scenario parameters:

CTG Emissions During Commissioning

Gas turbine commissioning is the process of initial startup, tuning and adjustment of the new CTGs and auxiliary equipment and of the emission control systems. The commissioning process consists of sequential test operation of each of the two gas turbines up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 410 operating hours for each CTG. With the planned sequential testing of the two gas turbines, the overall length of the commissioning period would be approximately 3 months. Commissioning of the proposed project may be phased into two commissioning periods each approximately 1.5 months long.

There are several commissioning modes. The first is the period prior to SCR system installation, when the combustor is being tuned. During this mode, the NO_x emissions control system would not be functioning and the combustor would not be tuned for optimum performance. CO emissions would also be affected because combustor performance would not yet be optimized. The second emissions scenario will occur when the combustor has been tuned but the SCR installation is not complete, and other parts of the gas turbine operating system are being checked out. Because the combustor would be tuned but the emission control system installation would not be complete, NO_x and CO levels could again be affected.

Noncriteria Pollutant Emissions

Noncriteria pollutants are compounds that have been identified as pollutants that pose a potential health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.²⁴ In addition to these nine compounds, the federal Clean Air Act listed 187 to 189²⁵ substances at different times as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The State of California defined a set of toxic air contaminants through Assembly Bill (AB) 2588, the Air Toxics "Hot Spots" Information and Assessment Act. The SJVAPCD published a list of compounds it defined as potential toxic air contaminants in its May 1991 Toxics Policy. Any pollutant that may be emitted from the Project and is on the federal New Source Review list, the federal Clean Air Act list, the AB2588 list or

²⁴ These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.

²⁵ Currently 187 substances are listed.

ATTACHMENT D

CTG Emissions Data

Table 8.2-1.1
Emissions and Operating Parameters for New Turbines
Avalon Energy Project

	Case 1	Case 5	Case 9	Case 2	Case 8	Case 10	Case 4	Case 8	Case 12
	101°F Full Load w/ DB ⁽¹⁾	83°F Full Load w/ DB ⁽¹⁾	32°F Full Load w/ DB ⁽¹⁾	101°F Full Load no DB	83°F Full Load no DB	32°F Full Load no DB	101°F 50% Load	83°F 50% Load	32°F 50% Load
Ambient Temp, °F	101	83	32	101	83	32	101	83	32
GT Load, %	100%	100%	100%	100%	100%	100%	50%	50%	50%
Both GTs Gross Power, MW	344.8	345.0	359.0	345.5	345.8	389.6	144.1	188.8	183.2
STG Gross Power, MW	290.8	273.3	254.7	171.6	176.1	177.7	118.3	127.8	130.8
Plant Gross Power Output, MW	635.6	618.3	613.7	517.2	521.7	537.2	262.5	286.2	313.9
Plant Net Power Output, MW	600.0	600.0	600.0	483.7	508.5	525.5	250.3	288.3	304.8
GTs Fuel Flow, kpph	156.4	156.4	181.8	156.4	158.4	181.8	87.2	88.2	102.2
DBs Fuel Flow, kpph	49.0	39.8	31.0	0.0	0.0	0.0	0.0	0.0	0.0
GTs Heat Input, MMBtu/hr (HHV)	1,794.2	1,794.3	1,855.4	1,795.6	1,795.4	1,858.3	1,001.4	1,104.3	1,171.9
DBs Heat Input, MMBtu/hr (HHV)	582.3	454.4	356.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, MMBtu/hr (HHV)	2,386.5	2,248.8	2,211.8	1,795.6	1,795.4	1,858.3	1,001.4	1,104.3	1,171.9
Stack Flow, lb/hr	3,653,000	3,650,000	3,759,000	3,828,000	3,830,000	3,743,000	2,232,700	2,338,800	2,413,300
Stack Flow, acfm	1,044,385	1,025,495	1,059,836	1,051,531	1,037,822	1,071,853	620,528	644,316	666,146
Stack Temp, °F	195.3	184.9	189.0	207.4	198.8	200.9	180.2	175.8	177.4
Stack exhaust, vol%									
O ₂ (dry)	11.40%	11.87%	12.34%	13.76%	13.77%	13.78%	14.46%	14.11%	13.93%
CO ₂ (dry)	5.42%	5.16%	4.89%	4.09%	4.08%	4.08%	3.70%	3.89%	3.99%
H ₂ O	10.54%	10.03%	9.12%	8.39%	8.28%	7.78%	8.07%	7.97%	7.83%
Emissions									
NO _x , ppmvd @ 15% O ₂	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NO _x , lb/hr ⁽²⁾	17.13	16.34	18.06	13.03	13.03	13.47	7.28	8.01	8.51
NO _x , lb/MMBtu (HHV)	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
SO ₂ , ppmvd @ 15% O ₂ ⁽³⁾	0.139	0.139	0.140	0.140	0.140	0.140	0.140	0.140	0.140
SO ₂ , lb/hr ^(2,3)	1.88	1.59	1.58	1.27	1.27	1.31	0.71	0.78	0.83
SO ₂ , lb/MMBtu (HHV) ⁽³⁾	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O ₂	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO, lb/hr ⁽²⁾	20.86	19.90	19.58	15.86	15.86	16.39	8.84	9.75	10.36
CO, lb/MMBtu (HHV)	0.0089	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088
VOC, ppmvd @ 15% O ₂ ⁽⁴⁾	2.0	2.0	2.0	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/hr ^(2,4)	5.98	5.88	5.59	3.17	3.17	3.28	1.77	1.95	2.07
VOC, lb/MMBtu (HHV) ⁽⁴⁾	0.0026	0.0025	0.0025	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018
PM ₁₀ , lb/hr ^(2,5)	11.81	11.27	10.78	9.00	9.00	9.00	9.00	9.00	9.00
PM ₁₀ , lb/MMBtu (HHV) ⁽⁵⁾	0.0050	0.0050	0.0049	0.0050	0.0050	0.0048	0.0090	0.0081	0.0077
PM ₁₀ , gr/SCF (dry) ⁽⁵⁾	0.00189	0.00179	0.00165	0.00142	0.00142	0.00137	0.00230	0.00220	0.00212
NH ₃ , ppmvd @ 15% O ₂	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH ₃ , lb/hr ⁽²⁾	35.39	33.57	32.88	26.28	26.25	28.98	14.80	18.08	17.02
CO ₂ , lb/MMBtu (HHV) ⁽⁷⁾	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CH ₄ , lb/MMBtu (HHV) ⁽⁸⁾	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
N ₂ O, lb/MMBtu (HHV) ⁽⁸⁾	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
CO ₂ , lb/hr ⁽⁹⁾	275,599	282,984	258,674	210,000	209,978	217,102	117,114	129,153	137,055
CH ₄ , lb/hr ⁽⁹⁾	30.7	29.2	28.8	23.4	23.4	24.1	13.0	14.4	15.2
N ₂ O, lb/hr ⁽⁹⁾	0.52	0.50	0.49	0.40	0.40	0.41	0.22	0.24	0.26

- 1) Includes duct burner firing only up to plant maximum output of 600 MW.
- 2) All mass flow values reported are on a per stack basis. Plant total mass flows are double these values.
- 3) All of the assumed 0.25 gr S in 100 scf of the fuel is assumed to be converted to SO₂ with no SO₂ conversion.
- 4) Based on an assumption that 20% of reported UHC emissions are VOCs.
- 5) Includes front-half (filterable) portion only. Back-half (condensable) portion is excluded.

6) CH₄ emission factor (kg/MMBtu) = 0.0059

ARB, *Draft Emission Factors for Mandatory Reporting Program, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.*

7) CO₂ emission factor (kg/MMBtu) = 53.05

ARB, *Draft Emission Factors for Mandatory Reporting Program, Table of Carbon Dioxide Emission Factors and Oxidation Rates for Stationary Combustion, August 10, 2007.*

8) N₂O emission factor (kg/MMBtu) = 0.0001

ARB, *Draft Emission Factors for Mandatory Reporting Program, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.*

ATTACHMENT E

SJVAPCD BACT Guidelines 1.1.2, 3.1.4, 3.1.8, and 3.4.2

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.1.2*

Last Update: 3/14/2002

Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings.**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Natural gas fuel with LPG backup		
NOx	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire).	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NOx@ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire).	
PM10	Natural gas fuel with LPG backup		
SO	Natural gas fuel with LPG backup		
VOC	Natural gas fuel with LPG backup		

** For the purpose of this determination, "small load swings" are defined as normal operational load fluctuations which are within the operational response range of an Ultra-Low NOx burner system(s).

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.4*

Last Update: 6/30/2001

Emergency Diesel I.C. Engine Driving a Fire Pump

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO		Oxidation Catalyst	
NOx	Certified NOx emissions of 6.9 g/bhp-hr or less		
PM10	0.1 grams/bhp-hr (if TBACT is triggered) (corrected 7/16/01) 0.4 grams/bhp-hr (if TBACT is not triggered)		
SOx	Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available.		
VOC	Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]	Catalytic Oxidation	

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.

2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.8*

Last Update: 4/4/2002

Emergency Gas-Fired IC Engine - > or = 250 hp, Lean Burn

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	= or < 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	> or = 80% control efficiency (Rich-burn engine with NSCR, or equal)
NOx	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)		= or > 90% control efficiency (Rich-burn engine with NSCR, or equal)
PM10	Natural gas fuel		
VOC	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	= or > 50% control efficiency (Rich-burn engine with NSCR, or equal)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.2*

Last Update: 10/1/2002

Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmv @ 15% O ₂ (Oxidation catalyst, or equal)	4.0 ppmv @ 15% O ₂ (Oxidation catalyst, or equal)	
NO _x	2.5 ppmv dry @ 15% O ₂ (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	2.0 ppmv dry @ 15% O ₂ (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	
PM ₁₀	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel, or equal		
SO _x	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more than 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmv @ 15% O ₂	1.5 ppmv @ 15% O ₂	

** Applicability lowered to > 50 MW pursuant to CARB Guidance for Permitting Electrical Generation Technologies. Change effective 10/1/02. Corrected error in applicability to read 50 MW not 50 MMBtu/hr effective 4/1/03.

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

ATTACHMENT F

Top Down BACT Analysis
(C-3953-10-0, -11-0, -12-0, -13-0, and -14-0)

Units C-3953-10-0 and -11-0 (Turbines)

I. NO_x Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.5 ppmvd @ 15% O₂ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 2.0 ppmvd @ 15% O₂ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 2.0 ppmvd @ 15% O₂ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)
2. 2.5 ppmvd @ 15% O₂ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing the use of a selective catalytic reduction system with NO_x emissions of 2.0 ppmv @ 15% O₂ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.0 ppmvd @ 15% O₂ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). The facility has proposed to use an inlet air filtration and cooling system, water injection, and a Selective Catalytic Reduction system on each of these turbines to achieve NO_x emissions of less than or equal to 2.0 ppmv @ 15% O₂ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). Therefore, BACT is satisfied.

Units C-3953-10-0 and -11-0 (Turbines)

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 6.0 ppmv @ 15% O₂ (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 4.0 ppmv @ 15% O₂ (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 4.0 ppmv @ 15% O₂ (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.
2. 6.0 ppmv @ 15% O₂ (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to limit CO emissions to 2.0 ppmv @ 15% O₂ (3-hour average, excluding startup and shutdown). This will be achieved with the use of an oxidation catalyst and firing on natural gas fuel. This is higher than the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be limiting the CO emissions to 2.0 ppmv @ 15% O₂ (3-hour average, excluding startup and shutdown) using an oxidation catalyst and firing on natural gas fuel. The facility has proposed to use an oxidation catalyst and fire the units on natural gas, to assure these turbines achieve CO emissions of less than or equal to 2.0 ppmv @ 15% O₂ (3-hour average, excluding startup and shutdown). Therefore, BACT is satisfied.

Units C-3953-10-0 and -11-0 (Turbines)

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% O₂

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 1.5 ppmvd VOC @ 15% O₂

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 1.5 ppmvd VOC @ 15% O₂
2. 2.0 ppmvd VOC @ 15% O₂

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing VOC emissions of 1.4 ppmvd @ 15% O₂ when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O₂ when it is fired with the duct burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O₂ did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O₂ emission factor will be determine to meet the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel or LPG with emissions of less than or equal to 2.0 ppmv @ 15% O₂. The facility has proposed to use natural gas fuel with emissions of less than or equal to 2.0 ppmv @ 15% O₂; therefore, BACT is satisfied.

Units C-3953-10-0 and -11-0 (Turbines)

IV. PM₁₀ Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM₁₀ emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use an air inlet filter, lube oil vent coalescer and natural gas fuel or equal. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of an air inlet filter, lube oil vent coalescer and natural gas fuel or equal. Avenal Power Center is proposing to use an air inlet filter, lube oil vent coalescer and natural gas fuel or equal; therefore, BACT is satisfied.

Units C-3953-10-0 and -11-0 (Turbines)

V. SO_x Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel; or
- Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC-regulated natural gas fuel
2. Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use PUC-regulated natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of PUC-regulated natural gas fuel. Avenal Power Center has proposed to fire each of the turbines solely on PUC-regulated natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-0 (Boiler)

I. NO_x Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- 9.0 ppmvd @ 3% O₂ (0.0108 lb/MMBtu) Ultra-Low NO_x main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies technologically feasible BACT as the following:

- 9.0 ppmvd @ 3% O₂ (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_x @ 3% O₂ igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 9.0 ppmvd @ 3% O₂ (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_x @ 3% O₂ igniter system (if the igniter system is used to heat the boiler at low fire)
2. 9.0 ppmvd @ 3% O₂ (0.0108 lb/MMBtu) Ultra-Low NO_x main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NO_x emissions from the boiler will not exceed 9.0 ppmv @ 3% O₂. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be NO_x emissions of less than 9.0 ppmvd @ 3% O₂. The facility has proposed NO_x emissions of less than 9.0 ppmv @ 3% O₂. Therefore, BACT is satisfied.

Units C-3953-12-0 (Boiler)

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for CO emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-0 (Boiler)

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for VOC emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-0 (Boiler)

IV. PM₁₀ Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM₁₀ emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1:2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-13-0 (Diesel IC engine powering fire water pump)

I. NO_x Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Certified NO_x emissions of 6.9 g/bhp-hr or less

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. Certified NO_x emissions of 6.9 g/bhp-hr or less

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NO_x emissions from the engine will not exceed 3.4 g/bhp-hr. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be Certified NO_x emissions of 6.9 g/bhp-hr or less. The facility has proposed NO_x emissions of less than 6.9 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-13-0 (Diesel IC engine powering fire water pump)

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any achieved in practice BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Oxidation Catalyst

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. Oxidation Catalyst

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

However, this engine has been UL Certified, and the UL certification does not include a oxidation catalyst, and the addition of a oxidation catalyst would void the UL certification, which is required for firewater pump engines. Therefore, the oxidation catalyst option will not be required.

Step 5 - Select BACT

BACT for the emission unit is satisfied by the facility's proposed CO emissions of 0.447 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-13-0 (Diesel IC engine powering fire water pump)

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Catalytic Oxidation

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. Catalytic Oxidation
2. Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

However, this engine has been UL Certified, and the UL certification does not include a catalytic oxidation system or a positive crankcase ventilation system, and the addition of a catalytic oxidation system or a positive crankcase ventilation system would void the UL certification, which is required for firewater pump engines. Therefore, both the catalytic oxidation system and the positive crankcase ventilation system options will not be required.

Step 5 - Select BACT

BACT for VOC emissions from this emergency diesel IC engine powering a firewater pump is having no control technology for VOC emissions. The applicant has proposed to install a 288 bhp emergency diesel IC engine powering a firewater pump with no control technology for VOC emissions; therefore BACT for VOC emissions is satisfied.

Units C-3953-14-0 (Natural gas IC engine powering electrical generator)

I. NO_x Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- NO_x emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- $\geq 90\%$ control efficiency (rich-burn engine with NSCR or equal)

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. $\geq 90\%$ control efficiency (rich-burn engine with NSCR or equal)
2. NO_x emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

1. $\geq 90\%$ control efficiency (rich-burn engine with NSCR or equal)

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for NO_x reduction is \$9,700 per ton of NO_x reduced.

Based upon the fact that there are only a few existing IC engine installations within this class and category of source that operate with emissions of ≤ 1.0 g NO_x/hp-hr, the District will assume that the Industry Standard will be 2.8 g NO_x/hp-hr (lb/MMBtu converted to g/hp-hr, Attachment I), pursuant to a AP-42 (07/00) values of uncontrolled four-stroke lean burn IC engines (< 90% load).

AP-42 publishes an uncontrolled NO_x value of 2.21 lb/MMBtu (90 – 105% load), which is approximately 13.4 g NO_x/hp-hr. Several major engine manufacturers were surveyed (Cummins, Caterpillar, and Waukesha) and the District found that lean burn engines sold by these engine manufacturers do not emit emissions close to the uncontrolled value for 90 – 105% load, published in AP-42. Based on the discussions with service representatives of each engine manufacturer, emissions were closer to the AP-42 value published for the < 90% load, which was around 2.5 g NO_x/hp-hr than it was for the value published for the 90 – 105% load. Therefore, industry standard for lean burn natural gas-fired emergency IC engine will be 2.8 g NO_x/hp-hr.

The proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

NO_x (annual):

$$\frac{2.8 \text{ g}}{\text{hp-hr}} \mid \frac{860 \text{ hp}}{1} \mid \frac{\text{lb}}{453.6 \text{ g}} \mid \frac{50 \text{ hr}}{\text{year}} = 265 \text{ lb NO}_x/\text{year}$$

$$PE_{NO_x} = 265 \text{ lb NO}_x/\text{year} = 0.1325 \text{ tons NO}_x/\text{year}$$

The proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a NO_x control efficiency of $\geq 90\%$ can be calculated as:

NO_x (annual):

$$\frac{7.4 \text{ g}^{(1)}}{\text{hp-hr}} \mid \frac{(1 - 0.9)}{1} \mid \frac{860 \text{ hp}}{1} \mid \frac{\text{lb}}{453.6 \text{ g}} \mid \frac{50 \text{ hr}}{\text{year}} = 70 \text{ lb NO}_x/\text{year}$$

$$PE_{NO_x} = 70 \text{ lb NO}_x/\text{year} = 0.035 \text{ tons NO}_x/\text{year}$$

District BACT policy demonstrates how to calculate the cost effectiveness of alternate basic equipment or process:

$$CE_{alt} = (\text{Cost}_{alt} - \text{Cost}_{basic}) \div (\text{Emission}_{basic} - \text{Emission}_{alt})$$

¹ Pursuant to AP-42 (07/00) the NO_x value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

where,

CE_{alt} = the cost effectiveness of alternate basic equipment expressed as dollars per ton of emissions reduced

$Cost_{alt}$ = the equivalent annual capital cost of the alternate basic equipment plus its annual operating cost

$Cost_{basic}$ = the equivalent annual capital cost of the proposed basic equipment, without BACT, plus its annual operating cost

$Emission_{basic}$ = the emissions from the proposed basic equipment, without BACT.

$Emission_{alt}$ = the emissions from the alternate basic equipment

The District conducted research to determine the appropriate cost information for installing a rich burn IC engine with a Non-Selective Catalytic Reduction System versus the cost information for installing a uncontrolled lean burn IC engine. Based on information from various engine manufacturers, the initial costs for installing an uncontrolled rich burn engine versus an uncontrolled lean burn engine would be minimal. The main difference in cost would be incurred in the installation of the NSCR system and the air to fuel ratio controller to the rich burn IC engine.

According to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" (pgs. V-2 & V-3), the approximate capital cost for installing a NSCR system for a 1,000 hp engine would be approximately \$28,000, the capital cost for installing an air to fuel ratio controller would be \$5,300, and the overall installation cost would be \$2,500. The CARB RACT/BARCT document also states the annual cost for operating and maintenance is between \$8,000 – 10,000, but these values are assuming full time operation. Since the proposed installation will be limited only to emergency operation and testing and maintenance, a conservative assumption of \$1,000 per year will be utilized for this evaluation.

Per District BACT Policy, the equivalent annual capital cost is calculated as follows:

$$A (\$/yr) = P \times [i \times (1 + i)^n] \div [(1 + i)^n - 1]$$

Where: A = Equivalent annual capital cost of the control equipment
P = Present value of the control equipment including installation
i = interest rate (10% used as default value)
n = equipment life (10 years used as default value)

Using a total capital cost of \$35,800 in the above equation results in an equivalent annual cost of \$5,826/year. Adding this equivalent annual cost to the annual operating cost of \$1,000/year, the ($Cost_{alt} - Cost_{basic}$) is equal to \$6,826/year. It should be noted that the operating the rich burn IC engine versus a lean burn IC engine would result in an efficiency loss and would potentially result in higher annual fuel expenses. These costs will be set aside for the present and only a partial cost analysis will be performed.

District BACT policy also requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of a NSCR system will control NO_x, CO, and VOC emissions. Therefore, the MCET is calculated as follows:

$$\text{MCET (\$/yr)} = (E_{\text{NO}_x} \times T_{\text{NO}_x}) + (E_{\text{CO}} \times T_{\text{CO}}) + (E_{\text{VOC}} \times T_{\text{VOC}})$$

Where:

- E_{NO_x} = tons-NO_x controlled/yr
- E_{CO} = tons-CO controlled/yr
- E_{VOC} = tons-VOC controlled/yr
- T_{NO_x} = District's cost effectiveness threshold for NO_x
= \$9,700/ton-NO_x
- T_{CO} = District's cost effectiveness threshold for CO
= \$300/ton-CO
- T_{VOC} = District's cost effectiveness threshold for VOCs
= \$5,000/ton-VOCs

Since this BACT cost effectiveness analysis is analyzing alternate basic equipment with a control technology which controls multiple pollutants; in order to calculate the cost effectiveness for the alternate basic equipment, the District will take the MCET and compare that value with the ($\text{Cost}_{\text{alt}} - \text{Cost}_{\text{basic}}$), to determine if this control technology is cost effective.

To determine E_{CO} , the District has to establish what Industry Standard is for CO emissions. As detailed above, engines with NO_x emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for CO emissions @ < 90% load (1.83 g CO/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

CO (annual):

$$\frac{1.83 \text{ g}}{\text{hp-hr}} \times \frac{860 \text{ hp}}{1} \times \frac{\text{lb}}{453.6\text{-g}} \times \frac{50 \text{ hr}}{\text{year}} = 173 \text{ lb CO/year}$$

$$PE_{\text{CO}} = 173 \text{ lb CO/year} = 0.0865 \text{ ton CO/year}$$

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB (pg. B-20), the CO control effectiveness from a NSCR system is greater than 80%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a CO control efficiency of ≥ 80% can be calculated as:

CO (annual):

$$\frac{11.6 \text{ g}^{(2)}}{\text{hp-hr}} \left| \frac{(1 - 0.8)}{1} \right| \frac{860 \text{ hp}}{1} \left| \frac{\text{lb}}{453.6\text{-g}} \right| \frac{50 \text{ hr}}{\text{year}} = 220 \text{ lb CO/year}$$

$PE_{CO} = 220 \text{ lb CO/year} = 0.11 \text{ ton CO/year}$

As demonstrated above, the CO emissions from the rich burn IC engine with a NSCR system are higher than the uncontrolled CO emissions from the lean burn IC engine. Therefore, CO will not be included in the MCET calculations.

To determine E_{VOC} , the District has to establish what Industry Standard is for VOC emissions. Again, as detailed above, engines with NO_x emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for VOC emissions (0.39 g VOC/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

VOC (annual):

$$\frac{0.39 \text{ g}}{\text{hp-hr}} \left| \frac{860 \text{ hp}}{1} \right| \frac{\text{lb}}{453.6\text{-g}} \left| \frac{50 \text{ hr}}{\text{year}} \right| = 37 \text{ lb VOC/year}$$

$PE_{VOC} = 37 \text{ lb VOC/year} = 0.0185 \text{ ton VOC/year}$

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB, the VOC control effectiveness from a NSCR system is greater than 50%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a VOC control efficiency of $\geq 50\%$ can be calculated as:

VOC (annual):

$$\frac{0.10 \text{ g}^{(3)}}{\text{hp-hr}} \left| \frac{(1 - 0.5)}{1} \right| \frac{860 \text{ hp}}{1} \left| \frac{\text{lb}}{453.6\text{-g}} \right| \frac{50 \text{ hr}}{\text{year}} = 5 \text{ lb VOC/year}$$

$PE_{VOC} = 5 \text{ lb VOC/year} = 0.0025 \text{ ton VOC/year}$

² Pursuant to AP-42 (07/00) the CO value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

³ Pursuant to AP-42 (07/00) the VOC value for uncontrolled four-stroke rich burn IC engines. (lb/MMBtu converted to g/hp-hr, Attachment I)

Calculating for the MCET derives the following:

$$E_{\text{NO}_x} = 0.1325 \text{ tpy} - 0.035 \text{ tpy} = 0.0975 \text{ tpy}$$

$$E_{\text{VOC}} = 0.0185 \text{ tpy} - 0.0025 \text{ tpy} = 0.016 \text{ tpy}$$

$$\text{MCET (\$/yr)} = (0.0975 \times \$9,700) + (0.016 \times \$5,000) = \$1,026/\text{year}$$

As presented above, $(\text{Cost}_{\text{alt}} - \text{Cost}_{\text{basic}})$ is equal to \$6,826/year.

This value is greater than the MCET; therefore, it has been determine that the installation of a rich burn IC engine with a NSCR system as alternate basic equipment is not cost effective using just the partial cost analysis.

2. NO_x emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

The applicant has proposed that the NO_x emissions from the engine will not exceed 1.0 g/bhp-hr. This is the highest ranking remaining control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be NO_x emissions of 1.0 g/bhp-hr or less. The facility has proposed NO_x emissions of less than 1.0 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-14-0 (Natural gas IC engine powering electrical generator)

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- ≤ 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies technologically feasible BACT as the following:

- 90% control efficiency (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- $\geq 80\%$ CO control efficiency catalyst (rich-burn engine with NSCR or equal)

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. 90% control efficiency (Oxidation catalyst, or equal)
2. $\geq 80\%$ CO control efficiency catalyst (rich-burn engine with NSCR or equal)
3. ≤ 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the engine will be equipped with an oxidation catalyst that will provide 90% control of CO emissions. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the used of an oxidation catalyst with 90% control of CO emissions. The facility has proposed to install an oxidation catalyst with 90% control of CO emissions. Therefore, BACT is satisfied.

Units C-3953-14-0 (Natural gas IC engine powering electrical generator)

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies technologically feasible BACT as the following:

- 90% control efficiency (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- $\geq 50\%$ control efficiency catalyst (rich-burn engine with NSCR or equal)

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. 90% control efficiency (Oxidation catalyst, or equal)
2. $\geq 50\%$ control efficiency catalyst (rich-burn engine with NSCR or equal)
3. ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the engine will be equipped with an oxidation catalyst with 90% control of VOC emissions. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the used of an oxidation catalyst with 90% control of VOC emissions. The facility has proposed to install an oxidation catalyst with 90% control of VOC emission. Therefore, BACT is satisfied.

ATTACHMENT G

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Air Pollution Control District Risk Management Review

To: Derek Fukuda
 From: Matthew Cegielski – Technical Services
 Date: April 28, 2008
 Facility Name: Avenal Power Center
 Location: Avenal Cutoff Road and San Luis Canal, Avenal, CA
 Application #(s): C-3953 10-0, 11-0, 12-0, 13-0, 14-0
 Project #: C-1080386

A. RMR SUMMARY

Categories	10-0 CT #1	11-0 CT #2	12-0 NG Aux Boiler	13-0 DICE Emeg Fire Pump	14-0 NG ICE Emeg Gen	Project Totals	Facility Totals
Prioritization Score	0.6	0.6	0.0	NA ¹	0.1	1.3	1.3
Acute Hazard Index	0.0	0.0	0.0	N/A ²	0.2	0.2	0.2
Chronic Hazard Index	0.0	0.0	0.0	N/A ²	0.0	0.0	0.0
Maximum Individual Cancer Risk (10 ⁻⁶)	0.02	0.02	0.01	0.01	0.0	0.1	0.1
T-BACT Required?	No	No	No	No	No		
Special Permit Conditions?	No	No	No	Yes	No		

- 1 Prioritization for this unit was not conducted since it has been determined that all diesel-fired IC engines will result in a prioritization score greater than 1.0.
- 2 Acute and Chronic Hazard Indices were not calculated since there is not risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

Units 10-0, 11-0, 12-0, 14-0

No special conditions required.

Units 13-0

1. The PM10 emissions rate shall not exceed 0.15 g/hp-hr based on US EPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

2. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102] N
3. The engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per year. [District Rules 2201, and 4702 and 17 CCR 93115] N

B. RMR REPORT

I. Project Description

Technical Services received a request on April 28, 2008 to perform a Risk Management Review for a proposed installation of a 600 MW Power Plant.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculations were calculated for the units as referenced in the following table.

Unit	Source	Reference
Combustion Turbine 10-0	HEARTS NG Turbine	VCAPCD
Combustion Turbine 11-0	HEARTS NG Turbine	VCAPCD
NG Auxiliary Boiler 12-0	HEARTS NG 10-100 MMBTU/Hr External Combustion	VCAPCD
NG Emergency ICE 14-0	HEARTS NG Internal Combustion <1000 HP	VCAPCD

The AERMOD model was used, with the parameters outlined below and meteorological data for 2004 from Fresno to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Combustion Turbines Unit 10-0, 11-0			
Source Type	Point	Location Type	Rural
Stack Height (m)	44.2	Closest Receptor (m)	1202
Stack Diameter. (m)	5.78	Type of Receptor	Residential
Stack Exit Velocity (m/s)	19.3	Max Hours per Year	8760
Stack Exit Temp. (°K)	367	Fuel Type	NG
Burner Rating (MMBtu/hr)	2,356.5		

Analysis Parameters NG Auxiliary Boiler 12-0			
Source Type	Point	Location Type	Rural
Stack Height (m)	11.3	Closest Receptor (m)	1202
Stack Diameter. (m)	0.81	Type of Receptor	Residence
Stack Exit Velocity (m/s)	12.2	Burner size MMBtu/hr	37.4
Stack Exit Temp. (°K)	476.5		

Analysis Parameters Diesel ICE Emergency Fire Pump 13-0			
Source Type	Point	Location Type	Rural
Stack Height (m)	5.49	Closest Receptor (m)	1202
Stack Diameter. (m)	0.15	Type of Receptor	Residence
Stack Exit Velocity (m/s)	42.2	PM ₁₀ g/hp-hr	0.15
Stack Exit Temp. (°K)	784.3	BHP	288
Max Hours per Year	50		

Analysis Parameters NG Emergency ICE Unit 14-0			
Source Type	Point	Location Type	Rural
Stack Height (m)	3.05	Closest Receptor (m)	1202
Stack Diameter. (m)	0.2	Type of Receptor	Residence
Stack Exit Velocity (m/s)	71.3	Throughput (MMBTU/yr)	355
Stack Exit Temp. (°K)	698	BHP	860
Max Hours per Year	50		

AAQA. In addition to the RMR, Technical Services performed an Ambient Air Quality Analysis (AAQA) on the project. Emissions are listed in the table below, for concentrations refer to the AAQA modeling profile.

	Stacks 1 and 2 Unit 10 and 11 Each CTs	Stack 3 Unit 12 Aux Boiler	Stack 4 Unit 13 Diesel Fire Pump	Stack 5 Unit 14 NG Emergency Generator
lbs/hr				
NOx	16.4	0.41	2.16	1.9
CO	72.8	1.38	0.28	1.14
PM10	9.2	0.19	0.04	0.06
SOx	1.9	0.11	0.0	0.02

lbs/yr	Each CTs	Aux Boiler	Diesel Fire Pump	Emergency Generator
hours/yr	8760	1251	50	50
NO _x	143,951	513	108	95
CO	637,788	1727	14	57
PM ₁₀	80,656	233	2	3
SO _x	16,694	132	0	1

Criteria Pollutant Modeling Results*

	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO _x	Pass	X	X	X	Pass
SO _x	Pass	Pass	X	Pass	Pass
PM ₁₀	X	X	X	Fail ¹	Fail ¹

*Results were taken from the attached PSD spreadsheet.

¹The predicted ambient air quality impacts for these criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with each unit is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

Attachments:

- A. HARP output files & AERMOD dispersion map
- B. Prioritization score with toxic emissions summary, AAQA
- C. RMR request from the project engineer

ATTACHMENT H

SO_x for PM₁₀ Interpollutant Offset Analysis

SO_x for PM₁₀ Interpollutant Offset Analysis Avenal Power Center, LLC

Facility Name: Avenal Power Center, LLC
Mailing Address: 500 Dallas Street, Level 31
Houston, TX 77002
Contact Person: Jim Rexroad
Telephone: (713) 275-6147
Application #: C-3953-10-0, -11-0, -12-0, -13-0, and -14-0
Project #: C-1080386
Location: NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base
Meridian on Assessor's Parcel Number 36-170-032
Complete: June 12, 2008

Date: June 12, 2008
Engineer: Derek Fukuda
Lead Engineer: Joven Refuerzo

I. Proposal

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 562.3 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

Facility C-3953 will become a major source for NO_x, VOC, and PM₁₀. There will be an increase in emissions for all pollutants and offsets are required for NO_x, VOC, and PM₁₀ emissions.

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (9/21/06)
(Section 3.30 and 4.13.3.2)

III. Process Description

Combined-Cycle Combustion Turbine Generators

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_x combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_x (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_x: 2.0 ppmvd @ 15% O₂
VOC: 2.0 ppmvd @ 15% O₂
CO: 4.0 ppmvd @ 15% O₂
SO_x: 0.00282 lb/MMBtu
PM₁₀: 0.005 lb/MMBtu

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_x, CO, and O₂ concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce steam. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_x in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_x to nitrogen and water, resulting in a reduced concentration of NO_x in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_x burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump

Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start

automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator

One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

IV. Equipment Listing

- C-3953-10-0:** 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_x COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

- C-3953-11-0:** 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_x COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

- C-3953-12-0:** 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

- C-3953-13-0:** 288 BHP CUMMINS MODEL CFP83-F40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

- C-3953-14-0:** 860 BHP CATERPILLAR MODEL G3512LE NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING A 500 KW ELECTRICAL GENERATOR

V. Interpollutant Offset Ratio Proposal SO_x for PM₁₀

Rule 2201, New and Modified Stationary Source Review, specifically allows the use of PM₁₀ precursor ERCs to offset PM₁₀ increases:

4.13.3 Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.

4.13.3.2 Interpollutant offsets between PM₁₀ and PM₁₀ precursors may be allowed.

Based on this language, an applicant must demonstrate an appropriate interpollutant offset ratio, based on an air quality analysis (that is, based on the science of the precursor-to-PM₁₀ relationship given the atmospheric chemistry and the meteorology of the locale).

The SO_x for PM₁₀ interpollutant ratio of 1.000:1 is based on District analysis (see Appendix A). The originating location of reduction of the proposed ERC certificates are greater than 15 miles from the proposed project. Therefore, a distance offset ratio of 1.5 applies. Combining the interpollutant and distance offset ratio, an overall SO_x for PM₁₀ offset ratio of $1.000 \times 1.5 = 1.5:1$ is valid for project C-1080386.

VI. Project Offset Calculations

i. C-3953-10-0 and C-3953-11-0 (Turbines)

a. **Maximum Hourly PE**

The maximum hourly potential to emit for NO_x, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NO_x emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO _x	160	17.20	13.55	13.55	240.00
CO	1,000	20.97	16.34	16.34	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM ₁₀	N/A ⁽¹⁾	11.78	8.91	8.91	23.56
SO _x	N/A ⁽¹⁾	6.65	5.23	5.23	13.30
NH ₃	N/A	32.13	25.31	25.31	64.26

b.. Maximum Annual PE

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_x emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

$$\begin{aligned} \text{SO}_x \text{ EF} &= (0.36 \text{ gr-S}/100 \text{ dscf}) \times (1 \text{ lb-S}/7000 \text{ gr}) \times (64 \text{ lb SO}_x/32 \text{ lb-S}) \times (1 \text{ scf}/1013 \text{ Btu}) \times (10^6 \text{ Btu/MMBtu}) \\ &= \mathbf{0.001 \text{ lb-SO}_x/\text{MMBtu}} \end{aligned}$$

CTG w/o Duct Burner Firing:

$$\begin{aligned} \text{SO}_x \text{ Emission Rate (lb/hr)} &= (1,856.3 \text{ MMBtu/hr}) \times (0.001 \text{ lb-SO}_x/\text{MMBtu}) \\ &= \mathbf{1.86 \text{ lb-SO}_x/\text{hr}} \end{aligned}$$

CTG w/ Duct Burner Firing:

$$\begin{aligned} \text{SO}_x \text{ Emission Rate (lb/hr)} &= (2,356.5 \text{ MMBtu/hr}) \times (0.001 \text{ lb-SO}_x/\text{MMBtu}) \\ &= \mathbf{2.36 \text{ lb-SO}_x/\text{hr}} \end{aligned}$$

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

¹ PM₁₀ and SO_x emissions during startups and shutdowns are lower than maximum hourly emissions.

Scenario 1) Weekend and Weekday Hot Start:

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM₁₀, SO_x, and NH₃ are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO _x	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	143,951 lb/year
CO	900 lb/hr (avg)	19.90 lb/hr	15.86 lb/hr	614,662 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	34,489 lb/year
PM ₁₀	N/A ⁽⁸⁾	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO _x	N/A ⁽⁸⁾	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH ₃	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 2) Weekend Shutdown and Weekday Hot Start:

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM₁₀, SO_x, and NH₃ are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO _x	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	19.90 lb/hr	15.86 lb/hr	637,788 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM ₁₀	N/A ⁽⁸⁾	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO _x	N/A ⁽⁸⁾	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH ₃	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO _x	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	19.90 lb/hr	15.86 lb/hr	142,166 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM ₁₀	N/A ⁽⁸⁾	11.27 lb/hr	9.00 lb/hr	80,656 lb/year
SO _x	N/A ⁽⁸⁾	2.36 lb/hr	1.86 lb/hr	16,694 lb/year
NH ₃	N/A	32.13 lb/hr	25.31 lb/hr	219,972 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO _x	143,951 lb/year	Scenario 1
CO	637,788 lb/year	Scenario 2
VOC	34,489 lb/year	Scenario 2
PM ₁₀	80,656 lb/year	Scenario 3
SO _x	16,694 lb/year	Scenario 3
NH ₃	219,972 lb/year	Scenario 3

ii. **C-3953-12-0 (Boiler)**

The PM₁₀ potential to emit for the boiler is calculated as follows, and summarized in the table below.

$$\begin{aligned}
 PE_{PM_{10}} &= (0.005 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) \\
 &= \mathbf{0.19 \text{ lb PM}_{10}/\text{hr}} \\
 &= (0.005 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (12 \text{ hr/day}) \\
 &= \mathbf{2.2 \text{ lb PM}_{10}/\text{day}} \\
 &= (0.005 \text{ lb/MMBtu}) * (37.4 \text{ MMBtu/hr}) * (1,248 \text{ hr/year}) \\
 &= \mathbf{233 \text{ lb PM}_{10}/\text{year}} \\
 &= (233 \text{ lb/year}) * (4 \text{ qtr/year}) \\
 &= \mathbf{58 \text{ lb PM}_{10}/\text{qtr}}
 \end{aligned}$$

Post Project Potential to Emit (PE2) (C-3953-12-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM ₁₀	0.19	2.2	58	233

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The PM₁₀ emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

$$\begin{aligned}
 PE_{PM_{10}} &= (0.059 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) \\
 &= \mathbf{0.04 \text{ lb PM}_{10}/\text{hr}} \\
 &= (0.059 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\
 &= \mathbf{0.9 \text{ lb PM}_{10}/\text{day}} \\
 &= (0.059 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\
 &= \mathbf{0.5 \text{ lb PM}_{10}/\text{qtr}} \\
 &= (0.059 \text{ g/hp}\cdot\text{hr}) * (288 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\
 &= \mathbf{1.9 \text{ lb PM}_{10}/\text{year}}
 \end{aligned}$$

Post Project Potential to Emit (PE2)				
(C-3953-13-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM ₁₀	0.04	0.9	0.5	2

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The PM₁₀ emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

$$\begin{aligned}
 PE_{PM_{10}} &= (0.034 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) \\
 &= \mathbf{0.06 \text{ lb PM}_{10}/\text{hr}} \\
 &= (0.034 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day}) \\
 &= \mathbf{1.5 \text{ lb PM}_{10}/\text{day}} \\
 &= (0.034 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr}) \\
 &= \mathbf{1 \text{ lb PM}_{10}/\text{qtr}} \\
 &= (0.034 \text{ g/hp}\cdot\text{hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year}) \\
 &= \mathbf{3 \text{ lb PM}_{10}/\text{year}}
 \end{aligned}$$

Post Project Potential to Emit (PE2) (C-3953-14-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM ₁₀	0.06	1.5	1	3

Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)						
Permit Unit	NO _x	CO	VOC	PM ₁₀	SO _x	NH ₃
C-3953-10-0	143,951	637,788	34,489	80,656	16,694	219,972
C-3953-11-0	143,951	637,788	34,489	80,656	16,694	219,972
C-3953-12-0	513	1,727	201	233	132	0
C-3953-13-0	108	14	12	2	0	0
C-3953-14-0	95	57	31	3	1	0
Post-project SSPE (SSPE2)	288,618	1,277,374	69,222	161,550	33,521	439,944

Total Emissions to be Offset

Pursuant to District Rule 2201, Section 4.6, emission offsets shall not be required for emergency equipment that is used exclusively as emergency standby equipment for electric power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year for non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power. Therefore the emission from the diesel-fired fire water pump and the natural gas-fired emergency standby generator are not required to be offset.

Emission to be Offset (lb/year)						
Permit Unit	NO _x	CO	VOC	PM ₁₀	SO _x	NH ₃
C-3953-10-0	143,951	637,788	34,489	80,656	16,694	219,972
C-3953-11-0	143,951	637,788	34,489	80,656	16,694	219,972
C-3953-12-0	513	1,727	201	233	132	0
Post-project SSPE (SSPE2)	288,415	1,277,303	69,179	161,545	33,520	439,944

Offset Calculations:

PM₁₀:

SSPE2 (PM₁₀) = 161,545 lb/year
 Offset threshold (PM₁₀) = 29,200 lb/year
 ICCE = 0 lb/year

Offsets Required (lb/year) = [(161,545 – 29,200 + 0) x DOR]
 = 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
33,087	33,086	33,086	33,086

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM₁₀ ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
 = 198,518 lb/year
 = 99.26 ton/yr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
49,630	49,629	49,629	49,630

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM₁₀ emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

	<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
ERC #C-896-4	80	80	80	80
ERC #N-721-4	0	0	3,215	0
ERC #N-723-4	0	0	985	0
ERC #S-2791-5	92,179	23,666	69,157	96,288
ERC #S-2790-5	12,862	491	0	8,499
ERC #S-2789-5	6	14	12	8
ERC #S-2788-5	5	7	3	6
ERC #N-762-5	21,000	21,000	21,000	21,000

Project PM₁₀ offset requirements

The applicant states either PM₁₀ ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM₁₀ offset requirements.

	<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
PM ₁₀ Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM ₁₀ emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM₁₀ and PM₁₀ precursors (i.e. SO_x) may be allowed. The applicant is proposing to use interpollutant offsets SO_x for PM₁₀ at an interpollutant ratio of 1.0:1 (see Appendix A). This interpollutant ratio has been evaluated by the District's modeler, James Sweet, Air Quality Project Planner. Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_x ERCs are being used to offset PM₁₀ emissions, the above applies to the SO_x ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
Remaining PM ₁₀ Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM ₁₀ emissions to be offset with SO _x ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO _x :PM ₁₀ ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
<hr/>				
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM ₁₀ emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO _x :PM ₁₀ ratio):	15,677	28,037	24,334	20,037
<hr/>				
	<u>1st Quarter</u>	<u>2nd Quarter</u>	<u>3rd Quarter</u>	<u>4th Quarter</u>
Remaining PM ₁₀ Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO _x :PM ₁₀ ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1 st qtr. ERCs applied to 2 nd qtr. ERCs:	-4,371	4,371	0	0
<hr/>				
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM ₁₀ emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO _x :PM ₁₀ ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_x and PM₁₀ emissions increases associated with this project.

VII. Conclusion

Approve use of an overall SO_x for PM₁₀ interpollutant offset ratio of 1.5:1 (1.000 x 1.5).

VIII. Recommendation

Compliance with all applicable rules and regulations is expected. Issue Authorities to Construct C-3953-10-0, -11-0, -12-0, -13-0, and -14-0 with a SO_x for PM₁₀ interpollutant offset ratio of 1.000:1.

PM10 Interpollutant Offset Ratio Analysis*

County	SOx for PM10	NOx for PM10	Notes
Fresno/Madera	1.866	4.202	Fresno/Madera is a combined evaluation with a shared source area
Kern	1.055	2.157	
Kings	1.000	2.282	Kings/Tulare is a combined evaluation with a shared source area
Tulare	1.000	2.298	Separate annual evaluations were made for the SIP, but the results establish this as one shared area The Kings/Tulare area has a small inventory of local SOx sources and is dominated by pollutant transport from the region; therefore the SOx for PM10 ratio is set to the minimum technical value of 1.000
Merced/Stanislaus	tbd	tbd	prior methodology for this area must be reevaluated for technical reasons
San Joaquin	not determined	not determined	insufficient data - a different approach may be required if needed

* Minimum offset ratio before consideration of distance or other adjustments

Notes for the Kings-Tulare Interpollutant Analysis

Combined emissions and inventories from Kings and Tulare Counties are used due to the evaluations of source interactions. This relationship was established by analysis performed for the SJVAPCD PM10 SIP.

The interpollutant relationship established for Kings County in this analysis would also be applicable to Tulare County.

Tons of SO_x to Equal Effect of 1 Ton of PM10 1.000 See SO_xPM10 worksheet for calculations Kings County

Tons of SO_x to Equal Effect of 1 Ton of PM10 1.000 See SO_xPM10 (2) worksheet for calculations Tulare County

A minimum value of 1.000 is established for technical reasons.

A relationship of less than one-to-one indicates that regional emissions are more dominant than local emissions.

Tons of NO_x to Equal Effect of 1 ton PM10 2.282 See NO_xPM10 worksheet for calculations Kings County

Tons of NO_x to Equal Effect of 1 ton PM10 2.298 See NO_xPM10 (2) worksheet for calculations Tulare County

Input data for the interpollutant worksheets are from the Annual and Annual based on Monthly worksheets

These worksheets are data and analyses submitted for the PM10 SIP

The AOI worksheet provides area of influence evaluations used to analyze specific episodes in the PM10 SIP

Episode evaluations reveal a variety of source areas for different episodes.

This justifies the use of the entire county, and in some cases more than one county, as the source area for annual interpollutant evaluation.

Episode trajectories revealed mixing between Kings and Tulare counties during episodes. Annual analysis showed almost identical contributions.

The combined emissions inventories of the two counties are evaluated in comparison to the annual chemical mass balance modeling for each site, and while the observations are slightly different, the resulting interpollutant relationships are almost identical.

**PM10 Interpollutant Offset Ratio Analysis
for Kings County**

Annual

PM10

	Notes	Units	Estimate	Uncertainty
"Vegetative Burning" Total	1	µg/m ³	6.55	2.00
Industry Component (30%)	2	µg/m ³	1.97	
Regional Background (20%)	3	µg/m ³	0.39	
Industry minus Background		µg/m ³	1.57	
County Contribution	4	µg/m ³	0.79	
Organic Carbon PM10 Inventory - Kings and Tulare County	5	ton/day	3.39	
County Impact		µg/m ³ per ton	0.23	0.30
				0.16

Nitrate

Ammonium Nitrate	6	µg/m ³	15.7	1.4
Regional Background	7	µg/m ³	1.00	
Ammonium Nitrate minus Background		µg/m ³	14.66	
County Contribution	8	µg/m ³	7.33	
NOx Inventory - Kings and Tulare County	9	ton/day	72.20	
County Impact		µg/m ³ per ton	0.10	0.11
				0.09
Tons of NOx to Equal Effect of 1-ton PM10	10		2.28	2.73
				1.74

1. Per SJVUAPCD and CARB, PM10 emissions from stationary industrial combustion sources are included in the Vegetative Burning category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM10 Attainment Plan (Kings - Hanford monitoring station).
2. Per SJVUAPCD, 30% of this category is attributed to stationary industrial combustion sources.
3. Per SJVUAPCD, regional background is estimated to be 20% of net concentration after previous adjustment to Vegetative Burning category.
4. Contribution from sources within Kings County is 50% of net concentration after previous adjustments to Vegetative Burning category.
5. Organic carbon PM10 inventory for Kings County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
6. Ammonium nitrate category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM10 Attainment Plan (Kings - Hanford monitoring station).
7. Per SJVUAPCD, regional background of ammonium nitrate is estimated to be 1 µg/m³.
8. Contribution from sources within Kings County is 50% of net concentration after previous adjustment to Vegetative Burning category.
9. NOx inventory for Kings County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
10. PM10 County Impact divided by Ammonium nitrate County Impact.

**PM10 Interpollutant Offset Ratio Analysis
for Kings County**

**Annual
PM10**

	Notes	Units	Estimate	Uncertainty	
"Vegetative Burning" Total	1	µg/m ³	6.6	2.0	"Annual based on Monthly" speciation worksheet cells G7 and H7
Industry Component (30%)	2	µg/m ³	1.97		"Kings - Hanford" worksheet for speciated rollback analysis
Regional Background (20%)	3	µg/m ³	0.39		"
Industry minus Background		µg/m ³	1.57		"
County Contribution	4	µg/m ³	0.79		"
Organic Carbon PM10 Inventory - Kings and Tulare County	5	ton/day	3.39		" Required to use base year emissions that are related to the observed speciation
County Impact		µg/m ³ per ton	0.23	0.30	
				0.16	
Sulfate					
Ammonium Sulfate	6	µg/m ³	3.0	0.3	Annual based on Monthly, speciation worksheet cells M7 and N7
Regional Background	7	µg/m ³	1.00		"Kings - Hanford" worksheet for speciated rollback analysis
Ammonium Sulfate minus Background		µg/m ³	1.99		"
County Contribution	8	µg/m ³	0.99		"
NOx Inventory - Kings and Tulare County	9	ton/day	3.15		" Required to use base year emissions that are related to the observed speciation
County Impact		µg/m ³ per ton	0.32	0.35	
				0.28	
Tons of SOx to Equal Effect of 1 Ton of PM10	10		0.73	0.87	0.14 Minimum valid technical value = 1,000
				0.57	-0.17 Minimum valid technical value = 1,000

The Kings/Tulare area has a small inventory of local SOx sources and is dominated by pollutant transport from the region; therefore the SOx for PM10 ratio is set to the minimum technical value of 1,000

- Per SJVUAPCD and CARB, PM10 emissions from stationary industrial combustion sources are included in the Vegetative Burning category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM10 Attainment Plan (Kings - Hanford monitoring station).
- Per SJVUAPCD, 30% of this category is attributed to stationary industrial combustion sources.
- Per SJVUAPCD, regional background is estimated to be 20% of net concentration after previous adjustment to Vegetative Burning category.
- Contribution from sources within Kings County is 50% of net concentration after previous adjustments to Vegetative Burning category.
- Organic carbon PM10 inventory for Kings County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
- Ammonium sulfate category from Chemical Mass Balance modeling performed for the SJVUAPCD 2003 PM10 Attainment Plan (Kings - Hanford monitoring station).
- Per SJVUAPCD, regional background of ammonium sulfate is estimated to be 1 µg/m³.
- Contribution from sources within Kings County is 50% of net concentration after previous adjustment to Vegetative Burning category.
- NOx inventory for Kings County that contributes to this monitoring location; from SIP inventory with updates and adjustments based on CCOS study.
- PM10 County Impact divided by Ammonium Sulfate County Impact.

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Kings - Hanford , Annual, Design Value = 53	General Note	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning	Ammonium Nitrate Including associated water	Ammonium Sulfate	Marine	Unassigned		
1	Line 1 Source Contribution from Analysis	From CMB monthly analysis Feb 2000 to Dec 2000, adding January 2001 episode for chemistry equivalent to annual design value	From CMB	From CMB	From CMB	Estimated portion of mass included in Vegetative Burning =30%	From CMB minus estimated Organic Carbon from other sources	From CMB	From CMB	From CMB, if present	Unaccounted mass from CMB, if any.		
2	LINE 1	53.00	23.20	4.00	0.50	1.98	4.82	15.70	3.00	0.00	0		
3	Line 2 Natural and Transport Contribution, see "Background" sheet	Portion not included in rollback analysis, removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	0, no natural background, transport estimated at 0	0, no natural background, transport estimated at 0	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes biogenic emissions = 20%	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations. Includes wildfires and biogenic =20% + 10%	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	see background sheet for numerical estimate and episode adjustment. Removed prior to rollback as not subject to local control, added back to projected future concentrations	100% because marine salts are a natural emission	0, background estimate at maximum, no additional background estimate for unexplained mass		
4	LINE 2	7.78	4.0	0.0	0.0	0.4	1.4	1.0	1.0				
5	Line 3 Net for Rollback	Net for Rollback, default percentages adjustable for episode characteristics, applicable to all columns except as indicated						Net for non-linear rollback, default percentages adjustable for episode characteristics		Removed entirely from rollback, added back to result			
6	LINE 3	45.22	19.2	4.0	0.5	1.6	3.2	14.7	2.0	0.0	0.0		
7	Line 4 Local Contribution PM2.5-PM10 Area of Influence	Source contribution from smallest area of influence, representative of large particle primary source area, includes all PM size emissions in the area - Rolled back against local area of influence emission estimate	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net	70%PM10 50%PM2.5 of net, non-linear rollback	70%PM10 50%PM2.5 of net				70%PM10 50%PM2.5 of net
8	LINE 4	26.55	13.4	2.0	0.4	0.8	1.6	7.4	1.0				0.0
9	Line 5 Local Contribution Area of Influence of PM2.5	Rolled back against local PM2.5 area of influence emission estimates - episode specific adjustments based on meteorology and episode duration	15%PM10 30%PM2.5	15%PM10 30%PM2.5	15%PM10 30%PM2.5	15%PM10 30%PM2.5	15%PM10 30%PM2.5	15%PM10 30%PM2.5 non-linear rollback	15%PM10 30%PM2.5				15%PM10 30%PM2.5
10	LINE 5	10.61	2.9	1.2	0.1	0.48	1.0	4.4	0.6				0.0
11	Line 6 Sub regional Contribution	Rolled back against specified County(ies) emission estimates - episode specific adjustments based on meteorology and episode duration	10%PM10 15%PM2.5	10%PM10 15%PM2.5	10%PM10 15%PM2.5	10%PM10 15%PM2.5	10%PM10 15%PM2.5	10%PM10 15%PM2.5 non-linear rollback	10%PM10 15%PM2.5				10%PM10 15%PM2.5
12	LINE 6	5.80	1.9	0.6	0.1	0.24	0.5	2.21	0.30				0.0
13	Line 7 Regional Contribution	Rolled back against Valleywide emission estimates - episode specific adjustments based on meteorology and episode duration	5%PM10 5%PM2.5	5%PM10 5%PM2.5	5%PM10 5%PM2.5	5%PM10 5%PM2.5	5%PM10 5%PM2.5	5%PM10 5%PM2.5 non-linear rollback	5%PM10 5%PM2.5				5%PM10 5%PM2.5
14	LINE 7	2.28	1.0	0.2	0.0	0.08	0.2	0.74	0.10				0.0
15	Associated Emissions Categories	Based upon appropriate seasonal or annual inventory	PM10 paved roads+ PM10 unpaved roads+ PM10 farm operations+ PM10 construction+ PM10 windblown	PM10, TOG & CO onroad mobile+ PM10, TOG & CO 860 offroad equipment PM10, TOG & CO 870 farm equipment CO presumed to add minimal mass	Tire and brake wear as predicted by EMFAC2002	Total TOG minus motor vehicle, OC may also include a small portion of otherwise unassigned elemental carbon PM10 & CO Area, Stationary CO presumed to add minimal mass	PM10 & CO residential burning PM10 & CO waste burning and disposal PM10 cooking PM10 & CO fires CO presumed to add minimal mass	Total E.I. NOx (+ bacterial soil NOx estimate removed as natural background)	Total SOx	None, natural emission from the ocean, bay and delta waters	Total PM10		
16	1999 Emissions Inventory	(area of influence emissions inventory, each on a separate line for automated calculations)											
17	PM10	L1= Area 5	10.62726401	0.34354204		0.054081039	0.305464261		1.704288207				13.44158539
18		L2= Areas 5,6,7,8	39.31045835	1.76730805		0.270093113	3.393649713		2.96197731				45.81837827
19		Sr= Tulare, Kings	49.3218	2.5364		0.294086989	4.5008		4.5846				60.9543
20		R= SJV	230.9463	14.9088		1.92	24.7498		34.9152				305.5217
21	NOx	L1= Area 5							20.44159256				
22		L2= Areas 5,6,7,8							72.19531862				
23		Sr= Tulare, Kings							77.774				
24		R= SJV							585.1907				
25	TOG	L1= Area 5		5.87213601			91.01532476						
26		L2= Areas 5,6,7,8		26.9341378			277.6758468						
27		Sr= Tulare, Kings		34.3569			249.4981						
28		R= SJV		205.9787			1241.6439						
29	SOx	L1= Area 5							2.196043579				
30		L2= Areas 5,6,7,8							3.154201498				
31		Sr= Tulare, Kings							1.7891				
32		R= SJV							30.2452				

	A	B	C	D	E	F	G	H	I	J	K	L	M	
	Kings - Hanford Annual, Design Value = 53	General Note	Geologic and Construction	Mobile Exhaust	Tire and Brake Wear	Organic Carbon	Vegetative Burning			Ammonium Nitrate Including associated water	Ammonium Sulfate	Marine	Unassigned	
133														
134	PM10 2010 EI without new controls	L1= Area 5	11.71676418	0.31680007		0.078620969	0.348794278		1.692896835				14.5826762	
135		L2= Areas 5,6,7,8	43.74474024	1.5914437		0.402170266	4.202372951		2.997549258				50.95666471	
136		Sr= Tulare, Kings	54.7212	2.2327		0.438789405	5.5343		4.5763				67.0645	
137		R= SJV	255.0794	13.3523		2.63	27.9931		35.1798				331.6048	
138	PM10 2010 EI with new controls	L1= Area 5	9.60813547	0.30493694		0.078620969	0.320748552		1.637533764				11.78737321	
139		L2= Areas 5,6,7,8	35.87213872	1.53184933		0.402170266	3.864470062		2.296179391				40.43037948	
140		Sr= Tulare, Kings	44.8732	2.14909268		0.438789405	5.0893		3.8233				53.88789268	
141		R= SJV	205.8304	12.8523		2.63	26.3051		29.2888				265.2426	
142	NOx 2010 EI without new controls	L1= Area 5								13.78371425				
143		L2= Areas 5,6,7,8								49.36328821				
144		Sr= Tulare, Kings								52.7948				
145		R= SJV								401.8368				
146	NOx 2010 EI with new controls	L1= Area 5								12.44632863				
147		L2= Areas 5,6,7,8								44.57374448				
148		Sr= Tulare, Kings								47.8723089				
149		R= SJV								364.0558				
150	TOG 2010 EI without new controls	L1= Area 5		3.40459935			112.9643685							
151		L2= Areas 5,6,7,8		14.8601553			354.3705663							
152		Sr= Tulare, Kings		20.4143			322.0508							
153		R= SJV		111.1259			1484.1355							
154	TOG 2010 EI with new controls	L1= Area 5		3.40459935			112.7861795							
155		L2= Areas 5,6,7,8		14.8601553			353.8115854							
156		Sr= Tulare, Kings		20.4143			321.5426							
157		R= SJV		111.1259			1458.8195							
158	SOx 2010 EI without new controls	L1= Area 5									2.569842275			
159		L2= Areas 5,6,7,8									3.48721152			
160		Sr= Tulare, Kings									1.7466			
161		R= SJV									33.341			
162	SOx 2010 EI with new controls	L1= Area 5									2.537472797			
163		L2= Areas 5,6,7,8									3.453160991			
164		Sr= Tulare, Kings									1.7248			
165		R= SJV									27.083			
210														
211	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	14.8	0.9	0.8	0.5	0.5	0.5	1.6		5.8	1.2	0.0	
212	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	3.2	0.5	0.3	0.1	0.3	0.3	1.0		3.5	0.7	0.0	
213	Sub regional Contribution	=(2010 Sr/1999 Sr2) * LINE 6	2.1	0.3	0.2	0.1	0.1	0.2	0.5		1.7	0.3	0.0	
214	Regional Contribution	=(2010 R/1999 R) * LINE 7	1.1	0.1	0.1	0.0	0.0	0.0	0.2		0.6	0.1	0.0	
215	Natural Background contribution	= LINE 2	4.0	0.0	0.0	0.0	0.4	0.0	1.4		1.0	0.0	0.0	
217	2010-2011 projected Annual Result		51.85	25.2	1.8	1.1	0.7	1.3	1.0		4.6	12.6	3.2	0.0
218														
219	Local Contribution PM2.5-PM10 Area of Influence	=(2010 L1/1999 L1) * LINE 4	12.2	0.9	0.6	0.5	0.4	0.5	1.8		5.4	1.2	0.0	
220	Local Contribution Area of Influence of PM2.5	=(2010 L2/1999 L2) * LINE 5	2.6	0.5	0.3	0.1	0.3	0.3	0.8		3.3	0.7	0.0	
221	Sub regional Contribution	=(2010 Sr/1999 Sr2) * LINE 6	1.7	0.3	0.2	0.1	0.1	0.2	0.4		1.6	0.3	0.0	
222	Regional Contribution	=(2010 R/1999 R) * LINE 7	0.9	0.1	0.1	0.0	0.0	0.0	0.1		0.6	0.1	0.0	
223	Natural Background contribution	= LINE 2	4.0	0.0	0.0	0.0	0.4	0.0	1.4		1.0	0.0	0.0	
224	2010-2011 projected Annual Result		46.80	21.4	1.7	1.1	0.7	1.3	1.0		4.2	11.9	3.2	0.0
225														

ANNUAL Average, based on CMB results for February to December 2000 plus the Jan 2001 Episode

SITEID	CONC	UCONC	PCMASS	Design Value	Sum of species	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological		Geological	
								Mass		Mass		Mass		Mass		Mass		Profile	Unassigned
BGS	57.7	3.6	98.5	57.0	55.6	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8	FDKERANN	1.4
FSD	49.5	3.2	98.4	50.0	46.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3	FDFSDANN	3.1
HAN	51.5	3.3	104.1	53.0	52.9	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2	FDHANANN	0.1
VCS	52.5	3.3	99.6	54.0	51.8	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8	FDVCSANN	2.2

This analysis provides a seasonally adjusted annual average, using the January episode to reflect the dominant winter chemistry.

Annual based on Monthly

Bakersfield Golden State Monthly

SITEID	DATE	CONC	LCONC	PCMAS	RSQ	CHISQ	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
							Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
BGS	1/1/01	205	10.3	93.6	1.0	0.9	23.3	6.3	6.7	4.7	1.3	1.7	7.0	0.7	95.4	7.8	58.2	9.6
BGS	Feb	24.4	1.9	96.4	1.0	0.7	4.1	2.3	1.7	1.3	0.6	0.6	1.2	0.1	5.1	0.6	10.9	3.2
BGS	Mar	22.2	2.1	107.7	1.0	1.0	2.1	2.2	2.1	1.4	0.6	0.6	1.9	0.2	5.5	0.6	11.7	3.1
BGS	Apr	31.5	2.4	107.8	1.0	0.4	6.3	3.2	2.1	1.7	0.5	0.7	3.0	0.3	4.9	0.6	17.3	4.6
BGS	May*	34.6	2.5	118.5	1.0	0.5	0.3	0.4	5.3	2.6			3.1	0.3	4.5	0.5	27.8	5.7
BGS	Jun*	41.3	2.7	102.7	1.0	0.6	0.9	0.4	5.1	2.6			3.8	0.3	3.1	0.4	29.4	6.0
BGS	Jul*	37.0	2.6	101.3	0.9	2.2	7.1	1.1	0.2	1.4	2.4	1.4	2.1	0.2	2.2	0.3	23.4	5.9
BGS	Aug*	43.5	2.6	97.8	1.0	1.2	4.1	0.8	2.2	1.9	0.5	1.4	2.5	0.3	2.9	0.4	30.2	6.5
BGS	Sep*	78.6	4.7	98.3	0.9	1.2	3.5	1.4	4.5	3.3	0.8	2.7	3.0	0.4	3.6	0.4	61.9	12.5
BGS	Oct*	36.1	2.8	83.9	1.0	1.0	3.5	0.7	1.6	1.3	1.4	1.0	1.9	0.2	5.2	0.6	16.7	4.3
BGS	Nov	48.4	2.9	86.3	1.0	0.4	7.9	3.4	4.6	2.7	0.6	0.7	2.2	0.2	14.0	1.2	12.3	3.1
BGS	Dec	90.2	5.1	87.4	1.0	0.6	12.5	5.1	7.0	4.2	2.1	1.2	4.3	0.4	32.2	2.7	20.9	5.4

Min		22.2	1.9	83.9	0.9	0.4	0.3	0.4	0.2	1.3	0.5	0.6	1.2	0.1	2.2	0.3	10.9	3.1
Avg		57.7	3.6	98.5	1.0	0.9	6.3	2.3	3.6	2.4	1.1	1.2	3.0	0.3	14.9	1.3	26.7	5.8
Max		205.0	10.3	118.5	1.0	2.2	23.3	6.3	7.0	4.7	2.4	2.7	7.0	0.7	95.4	7.8	61.9	12.5

Fresno Drummond Monthly

SITEID	DATE	CONC	LCONC	PCMAS	RSQ	CHISQ	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
							Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
FSD	1/1/01	186	9.4	87.9	1.0	1.1	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	35.1	6.8
FSD	Feb	27.0	2.1	97.3	1.0	0.7	5.7	2.5	3.1	1.8	0.3	0.4	1.1	0.2	7.7	0.8	8.3	2.1
FSD	Mar	23.9	2.1	116.0	1.0	0.7	4.6	2.4	3.1	1.8	0.1	0.4	1.8	0.2	8.2	0.9	9.9	2.3
FSD	Apr	24.8	2.2	112.1	1.0	0.6	3.4	2.7	2.4	1.6	0.2	0.5	2.4	0.2	5.0	0.5	14.4	3.0
FSD	May**	20.0	2.1	99.5	1.0	0.6	0.3446	0.32946	2.1	1.4			2.3269	0.22637	2.4774	0.32112	12.6	1.7055
FSD	Jun*	34.1	2.5	105.8	1.0	1.0	1.9	0.4	3.8	2.3	0.0	0.6	4.2	0.4	3.6	0.4	22.5	3.8
FSD	Jul*	26.4	2.3	100.6	1.0	0.6	1.0	0.4	1.5	1.3			1.7	0.2	2.7	0.3	19.6	2.2
FSD	Aug*	38.2	2.5	90.2	0.9	2.7	3.8	0.7	0.9	1.5	1.4	0.9	2.0	0.3	3.3	0.4	23.1	4.3
FSD	Sep*	56.7	3.3	92.8	1.0	0.9	1.5	0.6	3.4	2.5	0.9	1.0	2.6	0.4	3.6	0.4	40.6	6.0
FSD	Oct*	50.7	3.4	93.5	1.0	0.5	1.8	0.4	4.5	2.6			2.2	0.3	8.4	0.8	30.6	3.3
FSD	Nov	40.5	2.6	95.7	1.0	0.4	11.9	3.3	4.5	2.7	0.4	0.4	2.1	0.2	13.1	1.2	6.8	1.8
FSD	Dec	65.8	3.9	89.7	1.0	0.8	13.7	4.3	7.3	3.8	0.8	0.6	3.2	0.3	23.4	2.0	10.6	2.6

Min		20.0	2.1	87.9	0.9	0.4	0.3	0.3	0.9	1.3	0.0	0.4	1.1	0.2	2.5	0.3	6.8	1.7
Avg		49.5	3.2	98.4	1.0	0.9	7.5	2.4	4.6	2.8	0.7	0.7	2.6	0.3	12.0	1.1	19.5	3.3
Max		186.0	9.4	116.0	1.0	2.7	40.1	11.3	18.5	9.6	2.5	1.5	5.0	0.7	62.4	5.1	40.6	6.8

Annual based on Monthly

Hanford Monthly

SITEID	DATE	CONC	UONC	PCMAS	RSQ	CHISO	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
							Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
HAN	1/7/01	185	9.6	102.9	1.0	0.4	27.6	9.7	14.7	7.8	1.7	1.1	7.2	0.7	96.9	7.9	42.4	7.7
HAN	Feb	20.0	1.8	105.0	0.9	0.5	5.0	1.7	1.4	1.0	0.0	0.3	1.4	0.2	8.6	0.9	4.6	1.3
HAN	Mar	21.4	2.0	100.3	0.9	0.5	4.0	1.8	1.6	1.0	0.2	0.3	1.8	0.2	7.1	0.7	6.8	1.8
HAN	Apr*	22.3	2.1	120.6	1.0	0.3	0.4	0.3	3.2	1.6			2.2	0.2	5.0	0.5	16.1	2.8
HAN	May*	24.4	2.1	107.3	1.0	0.3	1.1673	0.35652	2.4	1.4			2.4472	0.22382	3.7747	0.44049	16.4	2.79498
HAN	Jun*	31.3	2.5	107.9	1.0	0.4	3.2	0.5	2.4	1.6	0.2	0.6	3.8	0.3	4.1	0.5	20.1	4.1
HAN	Jul*	38.7	2.6	107.9	0.9	0.7	3.6	0.6	2.7	1.6	0.2	0.7	3.4	0.3	5.6	0.6	26.3	4.7
HAN	Aug*	43.3	2.6	103.7	0.9	0.5	4.2	0.6	1.9	1.5	0.3	0.8	2.0	0.2	2.7	0.4	33.8	5.7
HAN	Sep*	70.5	4.0	105.3	0.9	0.5	2.5	0.8	4.3	2.7	0.5	1.2	3.1	0.4	5.0	0.7	58.8	8.8
HAN	Oct*	51.8	3.4	90.9	1.0	0.3	1.0	0.5	3.7	2.2	0.2	0.8	2.4	0.3	7.6	0.8	32.2	5.8
HAN	Nov	46.4	2.8	107.6	1.0	0.4	13.5	3.6	4.8	2.9	1.0	0.5	2.4	0.3	17.7	1.5	10.5	2.7
HAN	Dec	62.8	3.6	89.4	1.0	0.5	12.4	3.4	4.4	2.5	0.9	0.5	3.7	0.4	23.9	2.1	10.7	2.8
Min		20.0	1.8	89.4	0.9	0.3	0.4	0.3	1.4	1.0	0.0	0.3	1.4	0.2	2.7	0.4	4.6	1.3
Avg		51.5	3.3	104.1	1.0	0.4	6.6	2.0	4.0	2.3	0.5	0.7	3.0	0.3	15.7	1.4	23.2	4.2
Max		185.0	9.6	120.6	1.0	0.7	27.6	9.7	14.7	7.8	1.7	1.2	7.2	0.7	96.9	7.9	58.8	8.8

Visalia Church Street Monthly

SITEID	DATE	CONC	UONC	PCMAS	RSQ	CHISO	Burning		Motor Vehicle		Tire/Brake		Sulfate		Nitrate		Geological	
							Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc	Mass	Unc
HAN	1/7/01	185	9.6	102.9	1.0	0.4	27.6	9.7	14.7	7.8	1.7	1.1	7.2	0.7	96.9	7.9	42.4	7.7
VCS	Feb	25.0	2.1	99.8	1.0	0.5	5.3	2.1	2.0	1.3	0.0	0.5	1.1	0.1	9.0	1.0	7.6	1.9
VCS	Mar	27.5	2.2	102.9	1.0	1.0	4.8	2.2	2.9	1.7	0.1	0.5	2.1	0.2	10.0	0.9	8.4	1.9
VCS	Apr	26.2	2.2	115.3	1.0	0.7	5.6	2.8	1.7	1.6	0.6	0.6	2.8	0.3	5.9	0.6	13.7	2.9
VCS	May**	29.1	2.3	112.8	1.0	0.7	5.4	3.6	1.4	1.6			2.8	0.3	3.8	0.5	19.4	3.2
VCS	Jun*	42.0	2.7	106.1	1.0	0.7	0.8	0.4	4.9	2.7			5.4	0.5	5.2	0.6	28.2	3.9
VCS	Jul*	34.7	2.5	107.8	0.9	1.4	3.7	0.6	1.8	1.7	0.5	1.1	2.9	0.3	4.9	0.6	23.7	3.8
VCS	Aug*	44.9	2.7	98.5	0.9	1.3	3.6	0.7	1.4	1.6	0.3	1.4	2.3	0.3	4.2	0.5	32.4	4.9
VCS	Sep*	59.1	3.5	84.4	0.9	1.3	3.4	0.8	1.9	1.9	0.7	1.6	3.0	0.3	4.8	0.6	36.0	5.7
VCS	Oct*	53.7	3.5	83.6	1.0	0.6	1.6	0.7	4.4	2.6	0.0	1.4	2.4	0.3	9.8	1.0	26.7	4.5
VCS	Nov	37.3	2.5	94.1	1.0	0.6	5.8	3.1	6.1	2.9			1.8	0.2	10.9	1.0	10.5	2.1
VCS	Dec	65.0	3.8	87.5	1.0	0.9	12.7	3.6	4.6	2.7	0.6	0.7	3.2	0.3	24.8	2.1	11.2	2.6
Min		25.0	2.1	83.6	0.9	0.4	0.8	0.4	1.4	1.3	0.0	0.5	1.1	0.1	3.8	0.5	7.6	1.9
Avg		52.5	3.3	99.6	1.0	0.9	6.7	2.5	4.0	2.5	0.5	1.0	3.1	0.3	15.9	1.5	21.7	3.8
Max		185.0	9.6	115.3	1.0	1.4	27.6	9.7	14.7	7.8	1.7	1.6	7.2	0.7	96.9	7.9	42.4	7.7

NOTES: Burning profile was switched from wood burning to agricultural burning based on ARB monthly emissions inventory estimates.
 Asterisk * denotes AgBWheat profile used; ** denotes WBAmond (some AgBWheat/WBAmond used in April/May)

Source Profiles

	<u>Jan-May and Nov-</u>	<u>Dec</u>	<u>June-Oct</u>	
Burning	22	WBOakEuc	27	AgBWheat*
Sulfate	57	Amsul	57	Amsul
Nitrate	60	Amnit	60	Amnit
Motor Vehicle	65	CAMV	65	CAMV
Tire/Brake	67	TireBrke	67	TireBrke
Geological	92	FDHANANN	92	FDHANANN
	93	FDFREANN	93	FDFREANN
	94	FDVCSANN	94	FDVCSANN
	95	FDKERANN	95	FDKERANN

Note: (not used if run came out negative)

		Rollback default percentage, adjust by episode properties					
			Local	PM2.5	Sub regional	Regional	Total
		Default 2.5-10	70	15	10	5	100
		Default 2.5	50	30	15	5	100
		Note: distribution of anthropogenic contribution after subtraction of background					
Mapping of local, PM2.5-local, and sub-regional based on trajectory analysis		Areas used					
24-hr date	Site Name	Value	Local	PM2.5	Sub regional	Regional	# of dates
11/6/97	Corcoran-Patterson Avenue	199					
12/31/98	Bakersfield-Golden State Highway	159					
	Visalia-N Church Street	160					
1/12/99	Oildale-3311 Manor Street	156	12	12,13	Kern	SJV	1
10/21/99	Corcoran-Patterson Avenue	174	6	5,6,7,8	Kings-Tulare	SJV	2
	Fresno-Drummond Street	162	3	3,4	Fresno-Madera	SJV	3
	Turlock-S Minaret Street	157	1	1,2	Stanislaus-Merced	SJV	4
11/14/99	Bakersfield-Golden State Highway	183	12	6,7,8,10,12	Kings-Tulare-Kern	SJV	5
12/11/99	Hanford-S Irwin Street	183					
12/17/99	Corcoran-Patterson Avenue	174	6	6,8	Kings-Tulare	SJV	6
12/23/99	Fresno-Drummond Street	168	3	3,4,7	Fresno-Tulare	SJV	7
	Hanford-S Irwin Street	156	5	5,6,8	Kings-Tulare	SJV	8
1/1/01	Bakersfield-5558 California Avenue	186	12	9,10,11,12	Kern	SJV	9
	Bakersfield-Golden State Highway	205	12	9,10,11,12	Kern	SJV	10
	Clovis-N Villa Avenue	155	3	3,4	Fresno-Madera	SJV	11
	Fresno-1st Street	193	3	3,4	Fresno-Madera	SJV	12
	Fresno-Drummond Street	186	3	3,4	Fresno-Madera	SJV	13
	Oildale-3311 Manor Street	158	12	9,10,11,12	Kern	SJV	14
1/4/01	Bakersfield-5558 California Avenue	190	12	10,12,13	Kern	SJV	15
	Bakersfield-Golden State Highway	208	12	10,12,13	Kern	SJV	16
	Fresno-Drummond Street	159	3	3,4	Fresno-Madera	SJV	17
	Oildale-3311 Manor Street	195	12	10,12,13	Kern	SJV	18
1/7/01	Bakersfield-5558 California Avenue	159	12	10,12	Kern	SJV	19
	Bakersfield-Golden State Highway	174	12	10,12	Kern	SJV	20
	Corcoran-Patterson Avenue	165	6	6,8,10,12	Kings-Tulare-Kern	SJV	21
	Hanford-S Irwin Street	185	5	5,6,7,8,10	Kings-Tulare-Kern	SJV	22
	Modesto-14th Street	158	1	1,2	St-Me-Ma- Fr-Tu	SJV	23
11/9/01	Hanford-S Irwin Street	155	5	5,7,8	Kings-Tulare	SJV	24

Annual	County	Value	Local	PM2.5	Areas used				
	Kern	57	12	Kern	Sub regional	Regional			
					Kern	SJV			

PM-10 SIP Regions based on 4k CCAQS Domain (county influenced cells)

Derek Fukuda

From: Jim Rexroad [Jim.Rexroad@macquarie.com]
Sent: Monday, June 09, 2008 3:51 PM
To: Derek Fukuda
Cc: Eric Walther; Tracey Gilliland
Subject: Certificates used for Avenal PDOC

Derek,

We are still finishing up the formal table submissions so you can see the actual breakdowns, but here is the list of certificates that we will be using for the project. Note that S-2813-1 will shortly have a transaction coming that will reduce the volume to 50 Tons and the S2321-2 certificate (I have a contract and the ownership change documents will come next week. We should be able to send you the formal table tomorrow or by Thursday. Call me if you have questions.

ERC Certificate No.

VOC

C-897-1
C-898-1
N-724-1
N-725-1
S-2813-1 (derived from)

NOx

C-899-2
N-722-2
N-720-2
N-726-2
N-728-2
C-902-2
S-2814-2
S-2321-2 (derived from)

SOx (conversion to PM10 at 1.4:1)

S-2791-5
S-2790-5
S-2789-5
S-2788-5
N-762-5

PM10
C-896-4
N-721-4
N-723-4

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Email disclaimer for Macquarie Cook Power Inc.: http://www.macquarie.com/us/mcp_disclaimer.htm

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ATTACHMENT I

Additional Supplemental Information

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES^a
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO _x ^c 90 - 105% Load	4.08 E+00	B
NO _x ^c <90% Load	8.47 E-01	B
CO ^c 90 - 105% Load	3.17 E-01	C
CO ^c <90% Load	5.57 E-01	B
CO ₂ ^d	1.10 E+02	A
SO ₂ ^e	5.88 E-04	A
TOC ^f	1.47 E+00	A
Methane ^g	1.25 E+00	C
VOC ^h	1.18 E-01	C
PM10 (filterable) ⁱ	7.71 E-05	D
PM2.5 (filterable) ⁱ	7.71 E-05	D
PM Condensable ^j	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane ^k	<4.00 E-05	E
1,1,2-Trichloroethane ^k	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene ^k	2.67E-04	D
1,3-Dichloropropene ^k	<2.64 E-05	E
2-Methylnaphthalene ^k	3.32 E-05	C
2,2,4-Trimethylpentane ^k	2.50 E-04	C
Acenaphthene ^k	1.25 E-06	C

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN
 ENGINES^a
 (SCC 2-02-002-53)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO _x ^c 90 - 105% Load	2.21 E+00	A
NO _x ^c <90% Load	2.27 E+00	C
CO ^c 90 - 105% Load	3.72 E+00	A
CO ^c <90% Load	3.51 E+00	C
CO ₂ ^d	1.10 E+02	A
SO ₂ ^e	5.88 E-04	A
TOC ^f	3.58 E-01	C
Methane ^g	2.30 E-01	C
VOC ^h	2.96 E-02	C
PM10 (filterable) ^{ij}	9.50 E-03	E
PM2.5 (filterable) ^j	9.50 E-03	E
PM Condensable ^k	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane ^l	2.53 E-05	C
1,1,2-Trichloroethane ^l	<1.53 E-05	E
1,1-Dichloroethane	<1.13 E-05	E
1,2-Dichloroethane	<1.13 E-05	E
1,2-Dichloropropane	<1.30 E-05	E
1,3-Butadiene ^l	6.63 E-04	D
1,3-Dichloropropene ^l	<1.27 E-05	E
Acetaldehyde ^{l,m}	2.79 E-03	C
Acrolein ^{l,m}	2.63 E-03	C
Benzene ^l	1.58 E-03	B
Butyr/isobutyraldehyde	4.86 E-05	D
Carbon Tetrachloride ^l	<1.77 E-05	E

btu=>ppm

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%	
Type of fuel (use table above)	4 GAS
O2 correction (i.e., 3%)	15 %
Enter LB/MMBTU emission factor	
NOx	0.847 LB/MMBTU
CO	0.130 LB/MMBTU
VOC (as methane)	0.000 LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS	
NOx	229.94 ppmv
CO	57.98 ppmv
VOC (as methane)	0.00 ppmv

pV = R*T	
pressure (p)	1 atm
universal gas constant (R*)	0.7302 atm-scf/lbmole-oR
temperature (oF)	60 oF
calculated	
molar specific volume (V)	379.5 scf/lbmole
Molecular weights	
NOx	46 lb/lb-mole
CO	28 lb/lb-mole
VOC (as methane)	16 lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F		
COAL (ANTHRACITE)	10100 DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780 DSCF/MMBTU	COAL
COAL (LIGNITE)	9860 DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160 DSCF/MMBTU	OIL
GAS (NATURAL)	8710 DSCF/MMBTU	GAS
GAS (PROPANE)	8710 DSCF/MMBTU	GAS
GAS (BUTANE)	8710 DSCF/MMBTU	GAS
WOOD	9240 DSCF/MMBTU	WOOD
WOOD BARK	9600 DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570 DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710 DSCF/MMBTU	GAS

btu=>ppm

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%	
Type of fuel (use table above)	4 GAS
O2 correction (i.e., 3%)	15 %
Enter LB/MMBTU emission factor	
NOx	2.270 LB/MMBTU
CO	0.130 LB/MMBTU
VOC (as methane)	0.000 LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS	
NOx	616.25 ppmv
CO	57.98 ppmv
VOC (as methane)	0.00 ppmv

pV = R*T	
pressure (p)	1 atm
universal gas constant (R*)	0.7302 atm-scf/lbmole-oR
temperature (oF)	60 oF
calculated	
molar specific volume (V)	379.5 scf/lbmole
Molecular weights	
NOx	46 lb/lb-mole
CO	28 lb/lb-mole
VOC (as methane)	16 lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F		
COAL (ANTHRACITE)	10100 DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780 DSCF/MMBTU	COAL
COAL (LIGNITE)	9860 DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160 DSCF/MMBTU	OIL
GAS (NATURAL)	8710 DSCF/MMBTU	GAS
GAS (PROPANE)	8710 DSCF/MMBTU	GAS
GAS (BUTANE)	8710 DSCF/MMBTU	GAS
WOOD	9240 DSCF/MMBTU	WOOD
WOOD BARK	9600 DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570 DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710 DSCF/MMBTU	GAS

Avenal Power Center, LLC
500 Dallas Street, Level 31
Houston, TX 77002

RECEIVED

JUL 03 2008

Permits Srvc
SJVAPCD

COPY

July 1, 2008

RE: Certification of Avenal Energy, owned by Avenal Power Center, LLC

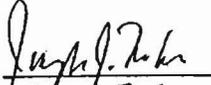
I, Stuart Zisman, on behalf of Avenal Power Center, LLC, hereby certify under penalty of perjury as follows:

1. I am authorized to make this certification on behalf of Avenal Power Center, LLC.
2. This certification is made pursuant to Section 4.15.2 of Rule 2201 of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.
3. To the best of the undersigned's knowledge, relative to Section 4.15.2 of District Rule 2201, Avenal Power Center, LLC. does not currently own, operate or control any Major Stationary Source or federal major modification in the State of California other than the proposed Avenal Energy Project.

Each of the statements herein is made in good faith. Accordingly, it is Avenal Power Center, LLC's understanding in submitting this certification that the SJVUAPCD shall take no action against Avenal Power Center, LLC or any of its employees based on any statement made in this certification.



Stuart Zisman
Vice President
Avenal Power Center, LLC



Joseph Forbes
Senior Lawyer

7/1/08
Dated

ATTACHMENT J

CEC Comments and Districts Responses

Public Comments / District Response

The comments from the California Energy Commission (Keith Golden) regarding the proposed Title V Operating Permit for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's response.

CEC Comments – Letter Dated August 12, 2008

CEC Comment #1:

Energy Commission staff is concerned that the integrity of the proposed mitigation may be adversely affected by the annual equivalency demonstration required by SJVAPCD Rule 2201, Section 7. This rule requires the District to demonstrate that emission reduction credits (ERCs) used by the project as offsets are surplus at the time of use.

Please describe whether District compliance with Rule 2201, Section 7 would require any of the offsets to be subject to discounting. Please also confirm whether the offsets identified for the project (on PDOC p. 47) are representative of real and surplus reductions, taking into account possible discounting under Rule 2201, Section 7. Additionally, please identify the original emission reduction site and date, and the method of reduction, for the ERCs that would be used to offset this project.

Districts Response:

Provided the FDOC is issued prior to a finding of failure of the equivalency system, the "at time of use" requirements don't apply. In addition, the District has not failed the equivalency demonstration, and does not expect to fail the demonstration this year. Finally, "at time of use" means at the time of the issuance of the permit (which the District considers to be the FDOC, in this case). Therefore, if a permit is issued without requiring "surplus at time of use credits", as the District subsequently fails to demonstrate equivalency with federal offsetting requirements, there is no affect on the permit. The "surplus at time of use" requirements would only kick in on permits issued after that date.

CEC Comment #2:

Staff would like to verify that using offsets would not disrupt regional progress in attaining PM10 or PM2.5 standards. The SJVAPCD, in Attachment H of the PDOC incorrectly states that the applicant proposed a one-to-one ratio. Please provide the District analysis in "Appendix A" with the Attachment H of the PDOC that supports compliance with Rule 2201, Section 4.13.3.

Districts Response:

The Districts PM₁₀ and PM_{2.5} plans both account for the growth in permitted sources in the air district. This growth is compared to the amount of offsets available in the Districts ERC bank to assure that the increase in emissions will not invalidate the Districts PM₁₀ and PM_{2.5} plans. Since the growth in permitted sources in the air district and the air districts available offsets have been taken into account when determining both the PM₁₀ and PM_{2.5} attainment plans, the use of offsets in this project will not result in the disruption of the attainment plans.

The interpollutant offset ratio for SO_x reductions for PM₁₀ increases will remain the same as stated in the PDOC. The Districts analysis of the interpollutant offset ratio has can be seen in Appendix A, which has been included in Attachment H of the PDOC.

CEC Comment #3:

Energy Commission staff concurs with the District that the NO_x emission limits for the combustion turbines and duct burners should apply on one-hour rolling averages during all operating conditions, except startup and shutdown periods (as described in PDOC p. 64 and PDOC Condition 26). However, the one-hour NO_x emission limit is not consistently described in the PDOC. Please confirm that the value calculated by the District is 17.20 lb/hr (PDOC Condition 26), not 17.44 lb/hr (as shown on p. 64).

Districts Response:

The hourly NO_x emission limit is 17.20 lb/hr. The condition on page 64 of the PDOC has been corrected to be consistent with condition 26 of the PDOC.

CEC Comment #4:

Energy Commission staff recommends limiting ammonia slip to the extent feasible. Although ammonia slip is intrinsic to operation of the selective catalytic reduction system, staff suggests that the District set a performance standard for ammonia slip. Guidance from CARB (Guidance for Power Plant Siting and Best Available Control Technology, September 1999) indicates that an ammonia slip limit of 5 parts per million by volume dry basis (ppmvd) should be achievable. Please consider revising the ammonia slip limits for the combustion turbines.

Districts Response:

Ammonia is an integral part of the NO_x emissions control system when using SCR. The District has no regulatory basis for restricting ammonia slip to 5 ppmv. Ammonia is not a criteria air contaminant or a "precursor" as defined in District Rule 2201. The District's BACT Clearinghouse does not specify an ammonia slip rate for combustion turbines using SCR. While ammonia emissions may be restricted as part of a health risk evaluation that determines an unacceptable health risk from the ammonia to exposed populations, this is not the case with Avenal Power Center. The risk due to all toxic air contaminant emissions, including 10 ppmv ammonia, was found to be not significant.

A high ammonia slip from the turbine will not lead to increased PM₁₀ formation in the atmosphere. The air basin currently has an excess of ammonia emissions; therefore lowering ammonia emissions will not reduce PM formation. This is demonstrated in the Districts PM_{2.5} plan which does not not rely on ammonia reductions to reduce PM_{2.5}, but rather relies largely on NO_x reductions.

Generally, increased ammonia injection rates, and therefore increased ammonia slip rates, are required to maintain NO_x BACT performance levels (2.0 ppmv) as the catalyst ages. Allowances for operation at the end of the economic life of a control technology and for periods of non-steady state operation (including startup and shutdown which can result in ammonia slip higher than 5 ppmv) are part of a BACT determination.

CEC Comment #5:

The New Source Performance Standard (NSPS) Subpart KKKK applies to stationary combustion turbines and emissions from any associated duct burners, and it replaces earlier requirements in NSPS Subpart Db and Subpart GG. The PDOC (p. 55) shows requirements from NSPS Subpart Db, although the project appears to be exempt. Similarly, the PDOC (p. 63) states that the turbines meet the applicability requirements of Subpart GG when the project appears to be exempt. Please clarify whether the project is indeed exempt from NSPS Subparts Db and GG.

Districts Response:

The stationary combustion turbines and duct burners in this project are subject to Subpart KKKK and are therefore exempt from Subparts Db and GG. An additional compliance section was added to state that the duct burners are exempt from Subpart Db. The compliance section for Subpart GG already states that the turbines are exempt from its requirements.

ATTACHMENT K

EPA Comments and District Responses

EPA Comments / District Response

The comments (from Shirley Rivera) regarding the proposed Title V Operating Permit for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

EPA Comments – Email Dated August 15, 2008

EPA Comment #1:

For the purposes of EPA's review of the PDOC evaluation and PDOC, although not required as part of our PSD permit application review/permit development process, we are in the process of identifying whether information provided by the Applicant through the PSD permit application process is consistent with the information in the District's evaluation. (Note: The Applicant provided sections from its CEC AFC that includes the Air Quality and Public Health sections, which presumably is information that the District evaluation also is based. PSD review has been triggered for NOx, CO, and PM.)

We would like to ensure that, at a minimum, those data sets and assumptions shared between the PSD and PDOC processes that contribute to the determination of the potential-to-emit, BACT, and assumptions for the air quality analysis/modeling are consistent. At this time, we simply would like to make the District aware that this evaluation is in process. To the extent that we identify inconsistencies during our review, we will address them as part of our PSD permit process.

Districts Response:

Thank you for the notification.

EPA Comment #2:

The emission limits proposed for each combustion turbine generator (CTG), Units C-3953-10-0 and C-3953-11-0, are 4.0 ppmvd @ 15% O₂. EPA is aware of CTGs achieving CO emissions less than 4.0 ppmvd @ 15% O₂. Therefore, please provide confirmation whether the District's evaluation considered achieved in practice CO ppm levels less than 4.0 ppmvd @ 15% O₂. If so, please provide reasons why a lower level was eliminated from consideration.

Districts Response:

The facility has proposed to lower their CO emission limit to 2.0 ppmvd @ 15% O₂.

ATTACHMENT L

CURE Comments and District Responses

Public Comments / District Response

The comments from California Unions for Reliable Energy (Loulena Miles, attorney at Adam Broadwell Joseph & Cardozo) regarding the proposed Title V Operating Permit for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Public Comments – Email Dated August 18, 2008

Public Comment #1:

THE SJVAPCD MUST SET LIMITS FOR GREENHOUSE GAS EMISSIONS

The law is now settled that greenhouse gases are pollutants subject to regulation under the Clean Air Act (CAA). Therefore, Air District permits must include a Best Available Control Technology (BACT) analysis and a permit limit for greenhouse gas emissions. The PDOC contains neither. Accordingly, the PDOC is deficient and must be revised to require BACT for greenhouse gas emissions.

Districts Response:

According to the Advanced Notice of Proposed Rulemaking for Regulating Greenhouse Gas Emissions under the Clean Air Act, Federal Register Vol. 73, No. 147, pg. 44420 (July 30, 2008),

“The Supreme Court’s conclusion that GHGs are “air pollutants” under the CAA did not automatically make these pollutants subject to the PSD program. A substance may be an “air pollutant” under the Act without being regulated under the Act. The Supreme Court directed the EPA Administrator to determine whether GHG emissions from motor vehicles meet the endangerment test of CAA section 202(a). A positive finding of endangerment would require the Administrator to then set standards applicable to GHG emissions from motor vehicles under the Act. The positive finding itself would not constitute a regulation requiring actual control of emissions. GHGs would become regulated pollutants under the Act if and when EPA subjects GHGs to control requirements under a CAA provision other than sections 112 and 211(o).”

EPA has not added control requirements for GHG’s in the CAA, therefore GHG’s are not regulated air pollutants and are not subject to the PSD program. In addition, the District has not been delegated the PSD program by EPA. Therefore, even if GHGs do become regulated pollutants, the District will continue to have no jurisdiction to regulate them until the EPA decides to delegate the PSD program to the District.

Based on the information discussed in the paragraphs above, an evaluation of GHG’s is not necessary to determine if this project is approvable.

Public Comment #2:

The PDOC limits CO emissions from the combustion turbine generators (CTGs) to 4.0 ppm at 15% O₂ regardless of whether the duct burners are firing based on the use of an oxidation catalyst.¹ The PDOC's determination that 4.0 ppm CO emissions are BACT is incorrect and fails to recognize that a number of power plants in the same category and class of source have achieved lower CO emission rates than proposed by the Applicant.

Districts Response:

The facility has proposed to lower their CO emission limit to 2.0 ppmvd @ 15% O₂.

Public Comment #3:

THE PM₁₀ BACT DETERMINATION FOR CTGs IS DEFICIENT

The PDOC limits PM₁₀ emissions from the combustion turbine generators (CTGs) to 9.0 lbs/hr without duct firing and 11.8 lbs/hr with duct firing, using natural gas fuel. The PDOC determined that BACT for PM₁₀ emissions from this Project's two General Electric (GE) 7FA CTGs would be the use of natural gas fuel with an LPG backup. This determination is incorrect and fails to recognize that a number of power plants in the same category and class of source that have achieved lower PM₁₀ emission rates than proposed by the Applicant.

Districts Response:

The District Top-Down BACT Analysis did not consider any PM₁₀ emissions control other than the use of an air inlet filter, lube oil vent coalescer and natural gas fuel.

District BACT Policy, Section IX.D, states that a cost effective analysis is not necessary for a project in which the most effective control alternative is selected. BACT Guideline 3.4.2 identifies BACT for PM₁₀ as the use of an air inlet filter, lube oil vent coalescer and natural gas fuel. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.

¹ SJVAPCD PDOC Attachment F-5.

Furthermore, District BACT Policy, Section IV, states that BACT Determinations are to be based upon the control technologies and methods for the same or similar source categories, listed in the District's BACT Clearinghouse for the calendar quarter during which the application is deemed complete. This application was deemed complete in the 1st quarter of 2008, therefore it is subject to the BACT Guideline for the source categories contained in the BACT Clearinghouse at that time. Based on the completion date of this application, the BACT requirements for the units in this project would not change even if the BACT Guidelines were changed in subsequent quarters.

The permitted PM₁₀ emissions limit for each CTG in this project is 11.78 lb/hr. This emission limit is lower than other GE Frame 7A, combined cycle, turbines with duct burners at power plants which have recently been approved by the CEC. The Victorville 2 Hybrid Power Plant (approved 7/16/08) was permitted with a PM₁₀ emission limit of 18.0 lb-PM₁₀/hr. The Colusa Generating Station (approved 4/23/08) was permitted with a PM₁₀ emission limit of 20.1 lb-PM₁₀/hr. The Los Medanos Energy Center referenced in your comment has a permitted PM₁₀ emission limit of 16.2 lb-PM₁₀/hr. In addition, the PM₁₀ emission limits for the two turbines at the Cosumnes Power Plant are not comparable since they are not equipped with duct burners.

Public Comment #4:

SJVAPCD's LIMITS ON AMMONIA SLIP ARE NOT BACT

The PDOC and attached permit conditions propose an unreasonably high ammonia slip limit of 10 ppm @ 15% O₂.² This ammonia slip rate was selected by the Applicant in the Application for Certification (AFC).³ The PDOC incorporates this rate without any BACT analysis. The PDOC dismisses the need to do a BACT analysis on the basis that "the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NOX. The emissions from a control device that is determined by the District to be BACT are not subject to BACT."

Districts Response:

Ammonia is an integral part of the NOx emissions control system when using SCR. The District has no regulatory basis for restricting ammonia slip to 5 ppmv. Ammonia is not a criteria air contaminant or a "precursor" as defined in District Rule 2201. The District's BACT Clearinghouse does not specify an ammonia slip rate for combustion turbines using SCR. While ammonia emissions may be restricted as part of a health risk evaluation that determines an unacceptable health risk from the ammonia to exposed populations, this is not the case with

² SJVACPD Avenal PDOC p. 7 and PDOC Attachment A.

³ Avenal Energy AFC, p. 6.2-41.

Avenal Power Center. The risk due to all toxic air contaminant emissions, including 10 ppmv ammonia, was found to be not significant.

A high ammonia slip from the turbine will not lead to increased PM₁₀ formation in the atmosphere. The air basin currently has an excess of ammonia emissions; therefore lowering ammonia emissions will not reduce PM formation. This is demonstrated in the Districts PM_{2.5} plan which does not rely on ammonia reductions to reduce PM_{2.5}, but rather relies largely on NO_x reductions.

You commented that initial ammonia slip rates below 5 ppmv have been observed on some combustion turbines using SCR. Generally, increased ammonia injection rates, and therefore increased ammonia slip rates, are required to maintain NO_x BACT performance levels (2.5 ppmv) as the catalyst ages. Allowances for operation at the end of the economic life of a control technology and for periods of non-steady state operation (including startup and shutdown which can result in ammonia slip higher than 5 ppmv) are part of a BACT determination.