ATTACHMENT P

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Jim Rexroad
Avenal Power Center LLC
500 Dallas Street, Level 31
Houston, TX 77002

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rexroad:

Enclosed is the District's final determination of compliance (FDOC) 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 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the PDOC were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

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

cc: Gary Rubenstein, Sierra Research

DEC 17 2010

Mike Tollstrup, Chief
Project Assessment Branch
Stationary Source Division
California Air Resources Board
PO Box 2815
Sacramento, CA 95812-2815

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Tollstrup:

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Sincerely,

David Warner
Director of Permit Services

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Enclosures

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

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DEC 17 2010

Gerardo C. Rios (AIR 3)
Chief, Permits Office
Air Division
U.S. E.P.A. - Region IX
75 Hawthorne Street
San Francisco, CA 94105

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rios:

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Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

www.valleyair.org www.healthyairliving.com

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Joseph Douglas
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Douglas:

Enclosed is the District's Final Determination of Compliance (FDOC) 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 36-170-035 in Avenal, CA.

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David Warner
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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 36-170-035 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-1100751 is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and 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

Facility Name:	Avenal Power Center, LLC
Mailing Address:	500 Dallas Street, Level 31 Houston, TX 77002
Contact Name:	Jim Rexroad
Telephone:	(713) 275-6147
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Telephone:	(713) 275-6148
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E-Mail:	tracey.gilliland@macquarie.com
Engineer:	Derek Fukuda, Air Quality Engineer
Lead Engineer:	Joven Refuerzo, Supervising Air Quality Engineer
Project #:	C-1100751
Application #'s:	C-3953-10-1, C-3953-11-1, C-3953-12-1, C-3953-13-1, and C-3953-14-1
Submitted:	March 3, 2010

Table of Contents

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.

While Avenal Power Center, LLC has already received a Determination of Compliance for the above described facility, they are now proposing to limit the annual facility wide NO_X emissions from 288,618 lb/year to 198,840 lb/year, and the annual facility wide CO emissions from 1,205,418 lb/year to 197,928 lb/year. The effect of these limits will be two-fold: one, should the facility operate to its full permitted extent, it will have the lowest annual average permitted emissions of NO_X (0.045 lb-NOx/MWh) and CO (0.044 lb-CO/MWh) of any natural gas fired power plant known to the District; and two, the facility will be limited to less than the 100 tons/year major source thresholds of the federal prevention of significant deterioration program.

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).

The facility submitted an application to revise their existing DOC issued under Project C-1080386. This revision consists of limiting the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year. The equipment the DOC was issued for in project C-1080386 has not been implemented. All units in this project will be treated as new emissions units.

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 Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
Subpart GG - Standards of Performance for Stationary Gas Turbines
Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Subpart JJJJ -Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Rule 4002 National Emissions Standards for Hazardous Air Pollutants (5/20/2004)
Subpart ZZZZ - National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
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 (10/16/08)
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 (9/20/07)
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 36-170-035 (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% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
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))
PM_{10}: 0.0048 lb/MMBtu (without duct burner firing)
0.0050 lb/MMBtu (with duct burner firing)

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 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 stream. 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-3953-10-1: 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-3953-11-1: 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-3953-12-1: 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-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 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-3953-10-1 and C-3953-11-1 (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% O_2. CO emissions of 2.0 ppmvd @ 15% O_2 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% O_2.

Emissions from natural gas-fired turbines include NO_X, CO, VOC, PM_{10}, 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 NO_2 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 N_2 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.

[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.

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 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 (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. 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 NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

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 (CO_2).

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-3953-12-1 (Boiler)

Emissions from natural gas-fired boilers include NO_X, CO, VOC, PM_{10}, 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-3953-13-1 (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-3953-14-1 (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 natural gas engine emissions are detailed below.

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

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

VII. GENERAL CALCULATIONS:

The facility has proposed to limit the annual facility wide NO_X emission to 198,840 lb/year, and the annual facility wide CO emission to 197,928 lb/year.

All PM_{10} emissions are assumed to be $PM_{2.5}$ emissions.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

- Heating value of natural gas is 1,013 Btu/scf (per applicant).

- Maximum daily emissions for each CTG for VOC, PM_{10} 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 PM_{10}, SO_X, and NH_3 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 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. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule.

- The facility has proposed a facility wide NO_X emission limit of 198,840 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for NO_X 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. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated NO_X emissions from an individual turbine operating at this scenario (calculated in Section VII.C.2) is not greater than the proposed facility wide NO_X emission limit; however the NO_X emissions from the operation of both turbines according to this scenario are far greater than the proposed facility wide NO_X emission limit. Therefore, the facility wide limit is a valid limit and the NO_X emissions from the turbines will ultimately be restricted by this limit.

- The facility has proposed a facility wide CO emission limit of 197,928 lb/year. To determine the validity of this limit, the 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. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated CO emissions from this scenario (calculated in Section VII.C.2) are greater than the proposed facility wide CO emission limit; therefore the facility wide emissions limit is a valid limit and the turbine's CO emissions will ultimately be restricted by this limit.

- Maximum annual emissions for each CTG for PM_{10}, SO_X, and NH_3 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-3953-12-1 (Boiler)

- External O_2 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 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
  = 0.00282 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.[3]
- Operating schedule of 12 hr/day and 1,248 hrs/year.

iii. C-3953-13-1 (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-3953–14-1 (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 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
  = 0.00282 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).

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

B. Emission Factors

i. C-3953-10-1 and C-3953-11-1 (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	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A(5)	N/A(4)

The maximum air contaminant mass emission rates (lb/hr) with and without duct burner firing, concentrations (ppmvd @ 15% O_2), 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, PM_{10}, CO, VOC, and NH_3 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:

Emission Rate (lb/hr) = CTG Max Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 13.55 lb-NO_X/hr

CO Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= 8.35 lb-CO/hr

VOC Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0018 lb-VOC/MMBtu)
= 3.34 lb-VOC/hr

PM_{10} Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0048 lb-PM_{10}/MMBtu)
= 8.91 lb-PM_{10}/hr

[4] PM_{10} and SO_X emissions during commissioning period are equal to the maximum hourly emissions during baseload facility operation.

SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= **5.23 lb-SO_X/hr**

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (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
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 1.832 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= **25.31 lb-NH3/hr**

Maximum Emission Rates and Concentrations Without Duct Burner Firing (@ 100% Load & 32 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	13.55	8.35	3.34	8.91	5.23	25.31
ppmvd @ 15% O_2 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 DOC application submittal.

<u>Maximum Emission Rate With Duct Burner Firing:</u>

The worst-case NO_X, SO_X, PM_{10}, CO, VOC, and NH_3 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:

Emission Rate (lb/hr) = [CTG Max Heat Input + Duct Burner Max Heat Input] (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= **17.20 lb-NO_X/hr**

CO Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= **10.60 lb-CO/hr**

VOC Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0025 lb-VOC/MMBtu)
= **5.89 lb-VOC/hr**

PM_{10} Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0050 lb-PM_{10}/MMBtu)
= **11.78 lb-PM_{10}/hr**

SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= **6.65 lb-SO_X/hr**

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (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 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 2.326 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x
1,013 (Btu/scf) x 2.326 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= 32.13 lb-NH3/hr

Maximum Emission Rates and Concentrations With Duct Burner Firing (@ 100% Load & 101 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
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 DOC 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[5]
Average Mass Emission Rate (per turbine, lb/hr)	80	900	16	N/A[6]	N/A[6]

ii. C-3953-12-1 (Boiler)

For the new boiler, the emissions factors for NO_X, CO, VOC, and PM_{10} 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% O_2 as provided by the Applicant
** SO_X emission factor based on the maximum proposed sulfur content of 1 gr/100 dscf.

(1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

iii. C-3953-13-1 (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 PM_{10} 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).

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

[5] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions during baseload facility operation.

$$^{*}0.0015\% \times \frac{7.1\, lb \cdot fuel}{gallon} \times \frac{2\, lb \cdot SO_2}{1\, lb \cdot S} \times \frac{1\, gal}{137{,}000\, Btu} \times \frac{1\, hp\ input}{0.35\, hp\ out} \times \frac{2{,}542.5\, Btu}{hp \cdot hr} \times \frac{453.6\, g}{lb} = 0.005\ \frac{g\ SOx}{hp \cdot hr}$$

iv. C-3953-14-1 (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 PM_{10} 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:

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

C. <u>Calculations</u>

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-3953-10-1 and C-3953-11-1 (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 NOx 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[(6)]	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 PM_{10}, 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 PM_{10}, 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:

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[(7)]	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A[(7)]	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

[6] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

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.

SO_X EF = (0.36 ~~gr S~~/100 ~~dscf~~) x (1 ~~lb S~~/7000 ~~gr~~) x (64 lb SO_X/32 ~~lb S~~) x (1 ~~scf~~/1013 ~~Btu~~) x (10^6 ~~Btu~~/MMBtu)
= 0.001 lb-SO_X/MMBtu

<u>CTG w/o Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 1.86 lb-SO_X/hr

<u>CTG w/ Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 2.36 lb-SO_X/hr

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

<u>Scenario 1) Weekend and Weekday Hot Start:</u>

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 PM_{10}, 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[(7)]	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A[(7)]	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 DOC application submittal.

<u>Scenario 2) Weekend Shutdown and Weekday Hot Start:</u>

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 PM_{10}, 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[(7)]	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A[(7)]	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 DOC 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(7)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(7)	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 DOC 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	197,928 lb/year	Facility Wide Limit
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
1st Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
2nd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
3rd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
4th Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993

ii. C-3953-12-1 (Boiler)

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

PE_{NOx} = (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.41 lb NO_X/hr**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **4.9 lb NO_X/day**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **513 lb NO_X/year**

= (513 lb NO_X/year) ÷ (4 qtr/year)
= **128 lb NO_X/qtr**

PE_{CO} = (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **1.38 lb CO/hr**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **16.6 lb CO/day**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **1,727 lb CO/year**

= (1,727 lb CO/year) ∗ (4 qtr/year)
= **432 lb CO/qtr**

PE_{VOC} = (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.16 lb VOC/hr**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.9 lb VOC/day**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **201 lb VOC/year**

= (201 lb/year) ∗ (4 qtr/year)
= **50 lb VOC/qtr**

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

PE_{SOx} = (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.11 lb SO_X/hr**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.3 lb SO_X/day**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **132 lb SO_X/year**

= (132 lb/year) ∗ (4 qtr/year)
= **33 lb SO_X/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-1)				
	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-3953-13-1 (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_{NOx} = (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **2.16 lb NO_X/hr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **51.8 lb NO_X/day**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **27 lb NO_X/qtr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **108 lb NO_X/year**

PE_{CO} = (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.28 lb CO/hr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb ∗ (24 hr/day)
= **6.8 lb CO/day**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **4 lb CO/qtr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **14 lb CO/year**

PE_{VOC} = (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.24 lb VOC/hr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **5.8 lb VOC/day**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **3 lb VOC/qtr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **12 lb VOC/year**

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

PE_{SOx} = (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.00 lb SO_X/hr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.1 lb SO_X/day**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **0 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-13-1)				
	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-3953-14-1 (Natural gas IC engine powering electrical generator)

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

PE_{NOx} = (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.90 lb NO_X/hr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **45.5 lb NO_X/day**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **24 lb NO_X/qtr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **95 lb NO_X/year**

PE_{CO} = (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.14 lb CO/hr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **27.3 lb CO/day**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **14 lb CO/qtr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **57 lb CO/year**

PE_{VOC} = (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.63 lb VOC/hr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **15.0 lb VOC/day**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **8 lb VOC/qtr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **31 lb VOC/year**

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

PE_{SOx} = (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.02 lb SO_X/hr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.4 lb SO_X/day**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-14-1)				
	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. The District is issuing a DOC for this project and not individual ATC's. Therefore, the SSPE2 will be determined by summing the potential emissions from the units included in the DOC.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)							
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3	$PM_{2.5}$ ***
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972	80,656
C-3953-11-1			34,489	80,656	16,694	219,972	80,656
C-3953-12-1			201	233	132	0	233
C-3953-13-1			12	2	0	0	2
C-3953-14-1			31	3	1	0	3
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**	**161,550**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.
*** All PM_{10} emissions are $PM_{2.5}$.

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)	$PM_{2.5}$ (lb/year)
Post-project SSPE (SSPE2)	198,840	197,928	69,222	161,550	33,521	161,550
Major Source Threshold	50,000	200,000	50,000	140,000	140,000	200,000
Major Source?	Yes	No	Yes	Yes	No	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, VOC, and PM_{10} 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, PM_{10} 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-3953-10-1 and C-3953-11-1 (Turbines)

The two CTGs will be equipped with operational CEMs for NO_X, CO, and O_2. 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 O_2 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 O_2 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 O_2 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 NOx 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-3953-12-1 (Boiler)

The boiler will be equipped with operational CEMs for NO_X, CO, and O_2. 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 NOx, 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-3953-10-1 and C-3953-11-1 (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 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 Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup NOx, 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 NOx, 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 O_2 - 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-3953-12-1 (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 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 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-3953-10-1 and C-3953-11-1 (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 a DOC 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-3953-10-1 and C-3953-11-1 (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, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, PM_{10}, and SO_X criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

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-3953-12-1 (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, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, and PM_{10} criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iii. C-3953-13-1 (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, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iv. C-3953-14-1 (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, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

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-3953-10-1 and C-3953-11-1 (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-3953-12-1 (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-3953-13-1 (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-3953-14-1 (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-3953-10-1 and -11-1 see Attachment F.

For Permit Unit C-3953-12-1 see Attachment F.

For Permit Unit C-3953-13-1 see Attachment F.

For Permit Unit C-3953-14-1 see Attachment F.

4. BACT Summary:

i. C-3953-10-1 and C-3953-11-1 (Turbines)

BACT has been satisfied by the following:

NO_X: 2.0 ppmv @ 15% O_2 (1-hour rolling average, except during startup/shutdown) with Dry Low NO_X Combustors, SCR with ammonia injection and natural gas fuel.

VOC: 1.5 ppmv @ 15% O_2 (without duct burner firing; 3-hour rolling average).
2.0 ppmv @ 15% O_2 (with duct burner firing; 3-hr rolling average).

PM_{10}: 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-3953-12-1 (Boiler)

BACT has been satisfied by the following:

NO_X: 9.0 ppmv @ 15% O_2 with Ultra Low NO_X burners and natural gas fuel.

VOC: Natural gas fuel.

PM_{10}: Natural gas fuel.

SO_X: Natural gas fuel.

iii. C-3953-13-1 (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

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

iv. C-3953-14-1 (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)

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]

<u>C. Offsets:</u>

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 PM_{10}. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_X, CO, VOC, PM_{10}, 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)	198,840	197,928	69,222	161,550	33,521
Offset Threshold	20,000	200,000	20,000	29,200	54,750
Offsets Required?	Yes	No	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.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_X, VOC, and PM_{10} 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 – Offset Threshold] + ICCE) x 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-3953-13-1 and C-3953-14-1 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 – Emergency Equipment - Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

<u>NO_X Offset Calculations:</u>

The facility has proposed to provide the same quarterly offsets that were required to be provided in the facility's initial project (C-1080386). The reason for this request is to enable the facility to preserve full flexibility to operate the facility at the previously permitted rates during any calendar quarter, provided the new annual emission limits are not exceeded. The facility is required to maintain a 12 month rolling calculation of their NO_X and CO emissions; therefore compliance with this quarterly limit will be enforceable. The quarterly offsets from project C-1080386 are shown below.

Quarterly Emissions to be Offset (Project C-1080386)

Annual Offsets = 268,415 lb/year * DOR

Quarterly Offsets $_{1st\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{2nd\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{3rd\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{4th\ Qtr}$ = 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					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (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					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (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.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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
3rd qtr. ERCs applied to 1st qtr. ERCs:	16,871	0	-16,871	0
3rd qtr. ERCs applied to 2nd qtr. ERCs:	0	22,509	-22,509	0
3rd qtr. ERCs applied to 4th 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-3953-13-1 (VOC) = 12 lb/year
C-3953-14-1 (VOC) = 31 lb/year
VOC offset threshold = 20,000 lb/year

Offsets = [69,222 – (12) – (31) – 20,000]
= 49,179 lb/year ∗ DOR

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

Offsets = (49,179 lb/year ÷ 4 qtr/year) ∗ DOR
= 12,294.75 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 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

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					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th 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					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th 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.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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.

PM_{10} Offset Calculations:

PM_{10} SSPE2 = 161,550 lb/year
C-3953-13-1 (PM_{10}) = 2 lb/year
C-3953-14-1 (PM_{10}) = 3 lb/year
PM_{10} Offset threshold = 29,200 lb/year

Offsets = [(161,550 – (2) – (3) - 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):

Offsets = (132,345 lb/year ÷ 4 qtr/year) ∗ DOR
= 33,086 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{2nd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{3rd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{4th\ Qtr}$ = 33,086 lbs of PM_{10} ∗ 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 PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year

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

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
PM_{10}	49,630	49,629	49,629	49,630	198,518

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 PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (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 PM_{10} offset requirements

The applicant states either PM_{10} 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 PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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 PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} 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 PM_{10} 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).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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
1st qtr. ERCs applied to 2nd 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 PM_{10} 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-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (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-3953-10-1, C-3953-11-1, and C-3953-12-1, 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-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} 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. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 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, VOC, and PM_{10}. 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-3953-10-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-11-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-12-1	4.9	16.6	1.9	2.2	1.3	0
C-3953-13-1	51.8	6.8	5.8	0.9	0.1	0
C-3953-14-1	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-3953-10-1 and -11-1 will each have a Potential to Emit greater than 100 lb/day for NO_X, CO, VOC, PM_{10}, SO_X, or NH_3 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	198,840	20,000 lb/year	Yes
CO	0	197,928	200,000 lb/year	No
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, VOC, and PM_{10} 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	198,840	0	198,840	20,000 lb/year	Yes
CO	197,928	0	197,928	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, PM_{10} 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 pubic 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.

Proposed Rule 2201 (DEL) Conditions:

The following condition will be included to demonstrate compliance with facility wide annual NO_X and CO emissions limits.

- Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

i. C-3953-10-1 and C-3953-11-1 (Turbines)

For the turbines, the DELs for NO_X, CO, VOC, PM_{10}, SO_X, and NH_3 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: NOx (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 SOx (as SO2) – 6.65 lb/hr. NOx (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: NOx (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 SOx (as SO2) – 5.23 lb/hr. NOx (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 NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 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: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 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 NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 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-3953-12-1 (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: NOx (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 SOx (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-3953-13-1 (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-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]

- 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-3953-14-1 (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-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]

- {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 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 PM_{10}. The increase in the ambient PM_{10} 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 ($\mu g/m^3$) - 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 ($\mu g/m^3$)				
	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 PM_{10} 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-3953-10-1 and C-3953-11-1

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 PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_X, CO, VOC, PM_{10}, 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 O_2. 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-3953-12-1

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-3953-13-1 and C-3953-14-1

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-3953-10-1 and C-3953-11-1

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-3953-12-1

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-3953-13-1 and C-3953-14-1

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

i. C-3953-10-1 and C-3953-11-1

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-3953-12-1

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-3953-13-1 and C-3953-14-1

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-3953-10-1 and C-3953-11-1

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-3953-12-1

No reporting is required to demonstrate compliance with Rule 2201.

iii. C-3953-13-1 and C-3953-14-1

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, VOC, and PM_{10} 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 not required to obtain a PSD permit.

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-3953-10-1, -11-1 and -14-1 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.[7]

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 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 SJVAPCD 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.[8] 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.

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

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-cc)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)
(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 PM_{10}.

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 mixtured 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 particulae 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 SO_2 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 SO_2 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 Part 60, Subpart JJJJ

The engine in this project is rated at over 100 bhp and per 60.4233(e) is subject to the limits presented in Table 1 of this subpart. The Table 1 limits as well as the proposed emissions are shown on the following table. This regulation does not specify an emissions averaging period.

	Table 1 Limit	Proposed Emissions	Compliant
NOx (g/bhp-hr)	2.0	1.0	Yes
CO (g/bhp-hr)	4.0	0.6	Yes
VOC (g/bhp-hr)	1.0	0.33	Yes

Therefore, the natural gas-fired IC engine in this project meets all applicable requirements of this subpart.

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% O_2 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% O_2 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: NOx (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 SOx (as SO2) – 6.72 lb/hr. NOx (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: NOx (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 SOx (as SO2) – 5.11 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

<u>Section 60.4330 - Standards for Sulfur Dioxide:</u>

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 SO_2 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 SO_2/J (0.060 lb SO_2/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)]

<u>Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection:</u>

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 O_2 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 O_2 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)]

<u>Section 60.4350 – CEMS Data and Excess NO_X Emissions:</u>

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 O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 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]

<u>Section 60.4355 – Parameter Monitoring Plan:</u>

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 SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/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 SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/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 SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/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 O_2 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. Susequent 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 fourth 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 NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} 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 O_2 - 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 SO_2 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 SO_2 concentration in the exhaust stream. Avenal Power Center is not proposing to measure the SO_2 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)

40 CFR 63 Subpart ZZZZ

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§6585(b) states, “A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.”

§6585(c) states, “An area source of HAP emissions is a source that is not a major source.”

The facility is not a major source as defined in §6585(b). Therefore, this facility is an area source of HAP emissions.

§6590(a) states, "An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand." Since the engines in this project are new stationary RICE's at an area source of HAP emissions, they are defined as affected sources.

§6590(a)(2) defines the criteria for an new stationary RICE as follows:

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

This facility is an area source of HAP emissions. The engines at this facility have not been constructed and therefore meets the definition of an new stationary RICE as defined in §6590(a)(2)(iii).

§6590(b)(1) states that an affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

Since the enignes in this project are not located at a major source of HAP emissions they do not qualify for the limited requirements stated above.

§6590(b)(2) and (3) apply to landfill or digester gas fired RICE's and existing RICE's. Since the engines in ths project are not exsiting RICE's and are fired on diesel fuel or natural gas, these sections do not apply to the RICE's in this project.

§6590(c) states that an affected source that is listed below must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

- new or reconstructed stationary RICE located at an area source,
- new or reconstructed stationary RICE located at a major source of HAP emissions and is a spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of less than 500 brake HP, a spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of less than 250 brake HP, or a 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP, a stationary RICE with a site rating of less than or equal to 500 brake HP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP,
- or a compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP,

Since both the RICE's in this project are new stationary RICE's located at an area source, they will demonstrate compliance with this Subpart by demonstrating compliance with the requirements of 40 CFR part 60 subpart IIII and for compression ignition engines and 40 CFR part 60 subpart JJJJ for spark ignited engines. As shown previously in this evaluation, the RICE's in this project meet the requirements of 40 CFR part 60 subpart IIII and subpart JJJJ; therefore they meet the requirements of this subpart.

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-3953-10-1 and C-3953-11-1 (Turbines)

The following condition will be listed on the DOC 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-3953-12-1 (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 DOC 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-3953-13-1 (Diesel IC engine powering fire water pump)

The following condition will be listed on the DOC 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-3953-14-1 (Natural gas IC engine electrical generator)

The following condition will be listed on the DOC 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-3953-10-1 (Turbine #1)	0.0	0.0	0.02	No
C-3953-11-1 (Turbine #2)	0.0	0.0	0.02	No
C-3953-12-1 (Auxiliary Boiler)	0.0	0.0	0.01	No
C-3953-13-1 (Diesel-Fired IC Engine Fire Pump)	N/A*	N/A*	0.01	No
C-3953-14-1 (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-3953-10-1 and –11-1 (Turbines)

PM Conc. (gr/scf) = (PM emission rate) x (7000 gr/lb)

PM_{10} emission rate = 11.78 lb/hr. Assuming 100% of PM is PM_{10}
Exhaust Gas Flow = 1,071,653 dscfm

PM Conc. (gr/scf)=[(11.78 lb/hr) ∗ (7,000 gr/lb)] ÷ [(1,071,653 ft^3/min) ∗ (60 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-3953-12-1 (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 (O_2) Concentration:	3%

$$\text{Excess Air Correction to F Factor} = \frac{20.9}{(20.9 - 3)} = 1.17$$

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

$$GL = 0.0035\ grain/dscf < 0.1\ grain/dscf$$

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-3953-13-1 (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:

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

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 DOC to ensure compliance:

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

iv. C-3953-14-1 (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:

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

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 DOC 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-3953-10-1 and C-3953-11-1 (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-3953-12-1 (Boiler)

District Rule 4301 Limits			
Pollutant	NO_2	Total PM	SO_2
C-3953-12-1 (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-3953-13-1 (Diesel IC engine fire pump)

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

iv. C-3953-14-1 (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-3953-12-1.

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-3953-12-1.

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-3953-12-1.

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% O_2 (0.011 lb/MMBtu), and
- the proposed CO emission factor is 50 ppmvd @ 3% O_2 (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 O_2, 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 NOx, 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 (O_2) 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 NOx 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 NOx 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-3953-13-1 and –14-1.

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-3953-13-1 and –14-1.

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-3953-14-1, 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-3953-13-1, 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 the DOC to ensure compliance:

C-3953-14-1 (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 the DOC to ensure compliance:

C-3953-13-1 (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 DOC 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-3953-14-1 (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-3953-10-1 and -11-1.

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 I) 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 equirements 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% O_2 (Standard option) and 3 ppmv @ 15% O_2 (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% O_2 (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: NOx (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 SOx (as SO2) – 6.65 lb/hr. NOx (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: NOx (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 SOx (as SO2) – 5.23 lb/hr. NOx (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% O_2. 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% O_2 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 NOx to N_2. 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 manufactúrer's recommended procedures.

<u>The basis for the requested additional duration.</u>

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 NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 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 O_2 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 NOx 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 or 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 NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} 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 O_2 - 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)]

<u>Conclusion:</u>

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 SO_2 on a dry basis averaged over 15 consecutive minutes:

i. C-3953-10-1 and –11-1 (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:

Volume of SO_X: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_X produced per MMBtu of fuel.
- Weight of SO_X as SO_2 is 64 lb/(lb-mol)
- $n = \frac{0.00282\ lb}{MMBtu} \times \frac{1\ (lb-mol)}{64\ lb} = 0.000045\ (lb-mol)$

- $R = \dfrac{0.7302\, ft^3 \cdot atm}{(lb - mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb - mol) \cdot \dfrac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

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

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

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

ii. C-3953-12-1 (Boiler)

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

Volume SO_2 = $\dfrac{n\ RT}{P}$

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi
R (Universal Gas Constant) = $\dfrac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot °R}$

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

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

Therefore, compliance with District Rule 4801 requirements is expected.

iii. C-3953-13-1 (Diesel IC engine powering a fire water pump)

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

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$\frac{0.000015\,lb-S}{lb-fuel}\times\frac{7.1\,\text{lb}}{\text{gal}}\times\frac{64\,\text{lb}-\text{SO}_2}{32\,\text{lb}-\text{S}}\times\frac{1\,\text{MMBtu}}{9{,}051\,\text{scf}}\times\frac{1\,\text{gal}}{0.137\,\text{MMBtu}}\times\frac{\text{lb}-\text{mol}}{64\,\text{lb}-\text{SO}_2}\times\frac{10.73\,\text{psi}-\text{ft}^3}{\text{lb}-\text{mol}-{}^\circ\text{R}}\times\frac{520{}^\circ\text{R}}{14.7\,\text{psi}}\times1{,}000{,}000 = 1.0\text{ ppmv}$$

Since 1.0 ppmv is ≤ 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 DOC 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-3953-14-1 (Natural gas IC engine powering an electrical generator)

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$2.85\;\frac{lb-S}{MMscf-gas}\times\frac{1\,scf-gas}{1{,}000\,Btu}\times\frac{1\,MMBtu}{8{,}578\,scf}\times\frac{1\,lb-mol}{64\,lb-S}\times\frac{10.73\,psi-ft^3}{lb-mol-{}^\circ R}\times\frac{520{}^\circ R}{14.7\,psi}\times1{,}000{,}000 = 1.97\text{ ppmv}$$

Since 1.97 ppmv is ≤ 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 DOC 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-3953-13-1.

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).

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 PM_{10} 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 DOC to ensure compliance:

- 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]

- 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]

<u>Right of the District to Establish More Stringent Standards:</u>

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-3953-13-1.

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 DOC 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 PM_{10} 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 DOC 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 DOC 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-3953-10-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-11-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-12-1	3020-02-H	37.4 MMBtu/hr boiler	$953.00
C-3953-13-1	3020-10-C	288 bhp IC engine	$222.00
C-3953-14-1	3020-10-E	860 bhp IC engine	$557.00

ATTACHMENT A

FDOC CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-3953-10-1:
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-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (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-3953-10-1, C-3953-11-1, and C-3953-12-1, 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-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} 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. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 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. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

8. {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]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. 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)]

12. 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]

13. 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 O_2 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)]

14. 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)]

15. The NO_X, CO and O_2 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)]

16. 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]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 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]

18. 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]

19. 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]

20. 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]

21. 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]

22. 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]

23. 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]

24. 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 NOx 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]

25. 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]

26. 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]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (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 SOx (as SO2) – 6.65 lb/hr. NOx (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. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (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 SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. 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)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. 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]

36. 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]

37. 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]

38. 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]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. 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 Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, 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]

42. Source testing (with and without duct burner firing) to measure the NOx, 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]

43. 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]

44. 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].

45. 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]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} 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)]

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

48. 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]

49. 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 O_2 - 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)]

50. 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)]

51. 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)]

52. 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)]

53. 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]

54. 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)]

55. 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]

56. 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]

57. 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]

58. 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]

59. 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]

60. 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]

61. 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]

62. 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]

63. 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]

64. 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]

65. 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]

66. 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]

67. 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-3953-11-1:
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-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (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-3953-10-1, C-3953-11-1, and C-3953-12-1, 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-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 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. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 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. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

8. {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]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. 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)]

12. 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]

13. 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 O_2 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)]

14. 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)]

15. The NO_X, CO and O_2 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)]

16. 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]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 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]

18. 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]

19. 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]

20. 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]

21. 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]

22. 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]

23. 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]

24. 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 NOx 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]

25. 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]

26. 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]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (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 SOx (as SO2) – 6.65 lb/hr. NOx (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. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (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 SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. 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)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. 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]

36. 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]

37. 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]

38. 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]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. 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 Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, 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]

42. Source testing (with and without duct burner firing) to measure the NOx, 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]

43. 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]

44. 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].

45. 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]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} 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)]

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

48. 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]

49. 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 O_2 - 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)]

50. 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)]

51. 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)]

52. 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)]

53. 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]

54. 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)]

55. 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]

56. 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]

57. 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-3953-12-1:
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-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (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-3953-10-1, C-3953-11-1, and C-3953-12-1, 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-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 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. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 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 DOC. 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 DOC. [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. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

11. {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]

12. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

13. {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]

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

15. {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

16. Emission rates from this unit shall not exceed any of the following limits: NOx (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 SOx (as SO2) - 0.00285 lb/MMBtu. [District Rules 2201, 4305, and 4306]

17. {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]

18. {3467} Source testing to measure NOx 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]

19. {3466} Source testing to measure NOx 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]

20. {2976} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

21. {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]

22. {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]

23. {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]

24. {2979} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

25. {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]

26. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

27. 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)]

28. 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)]

29. {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]

30. {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, 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-3953-13-1:
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. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

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. {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]

8. {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]

9. 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]

10. 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]

11. 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]

12. {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]

13. {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]

14. {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-3953-14-1:
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. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

5. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

6. {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]

7. {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]

8. {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

9. {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

10. 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]

11. {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]

12. {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]

13. 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]

14. {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]

15. {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]

16. {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]

17. {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]

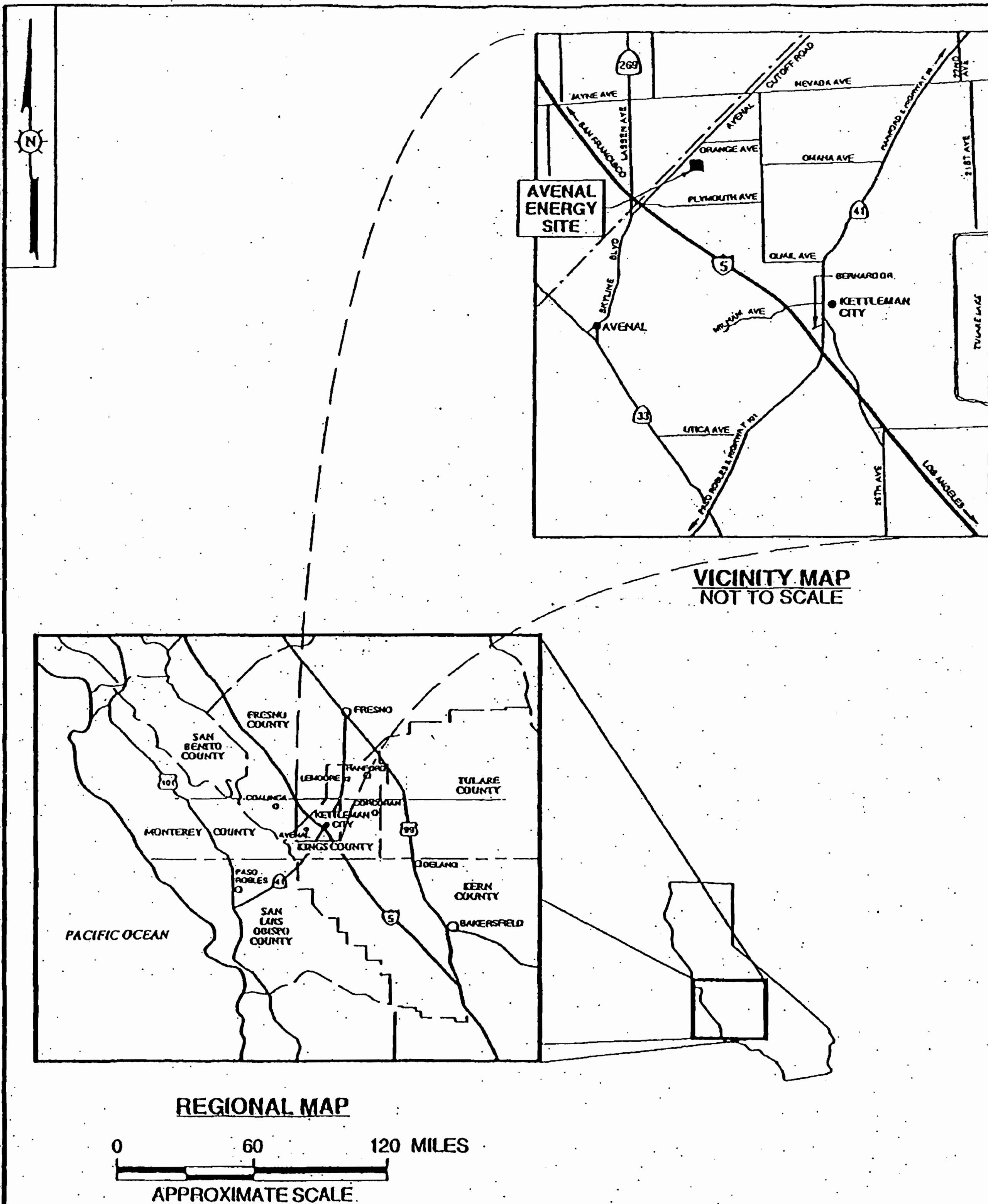
ATTACHMENT B

Project Location and Site Plan

ATTACHMENT C

CTG Commissioning Period Emissions Data

290317-AFC-2.0-1 REV1 09/05/08

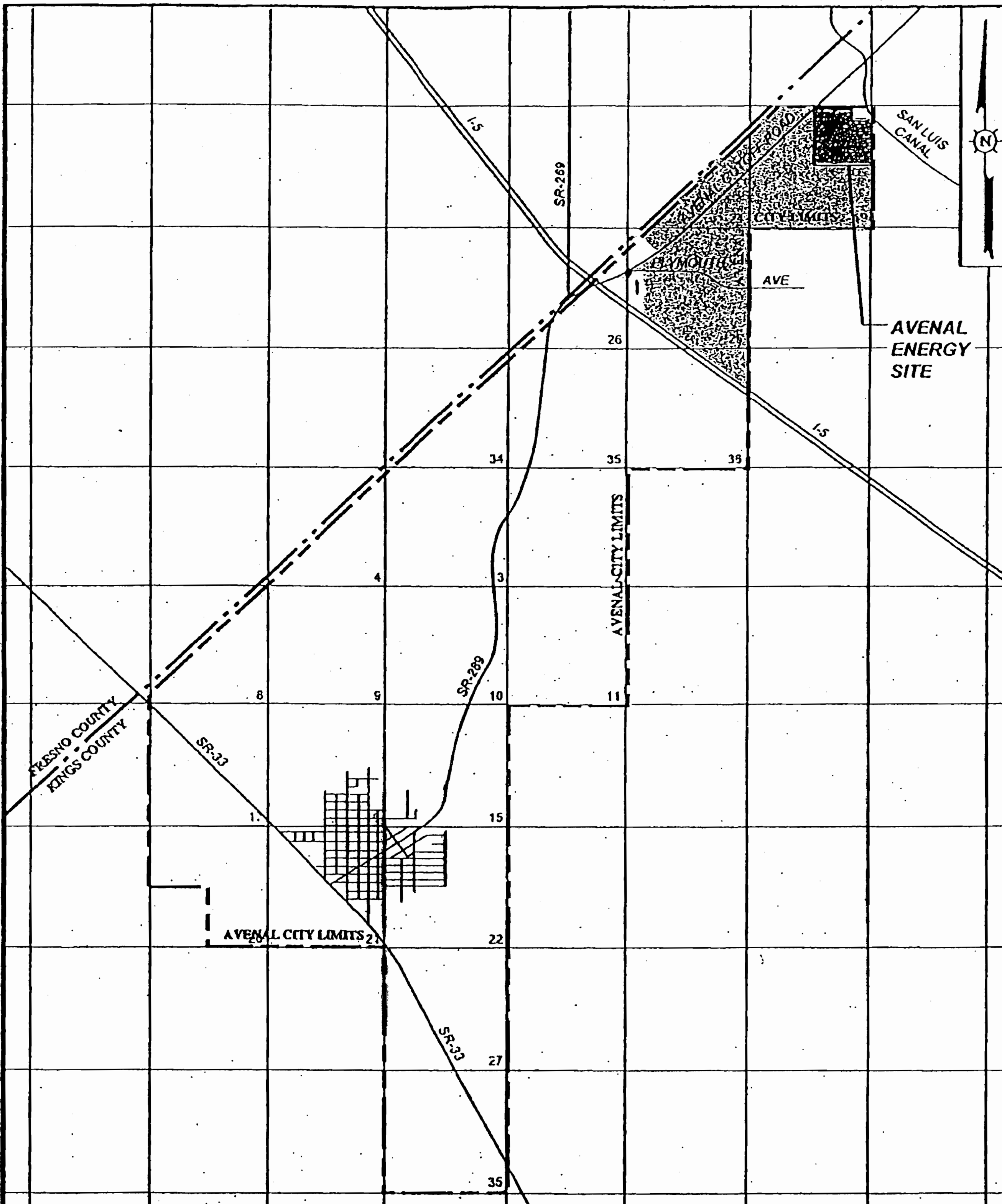


REGIONAL LOCATION MAP

FEDERAL ENERGY AVENAL, LLC

AVENAL ENERGY | FIGURE 2.0-1

280317-AFC-2.0-2 REV.09/13/01



LEGEND

INDUSTRIAL ZONE (CITY OF AVENAL GENERAL PLAN AND ZONING ORDINANCE)

0 6,000 12,000 FEET

SCALE

REFERENCE: CITY OF AVENAL GENERAL PLAN.

1 36.074 -120.093

AV

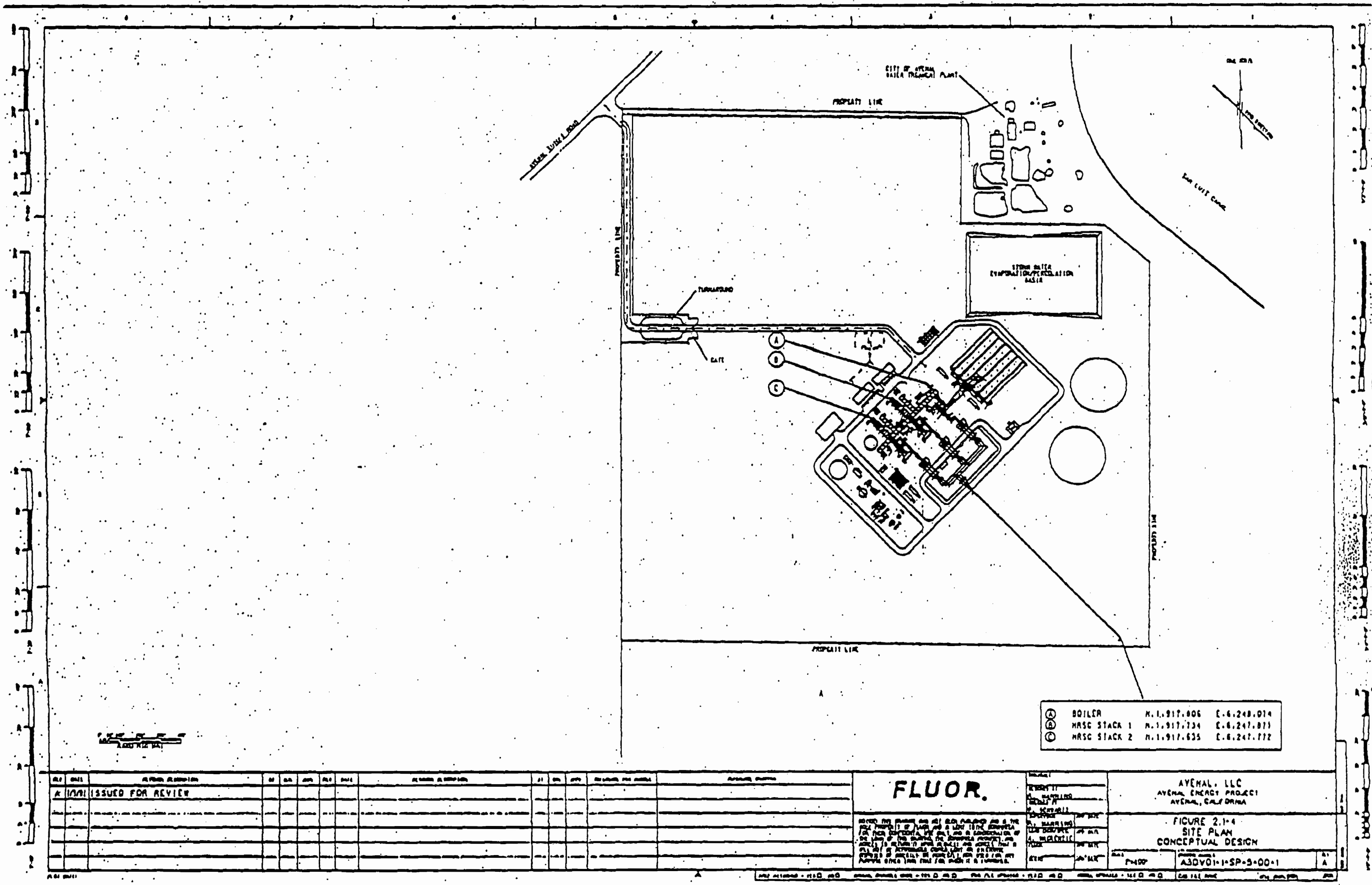
SITE LOCATION

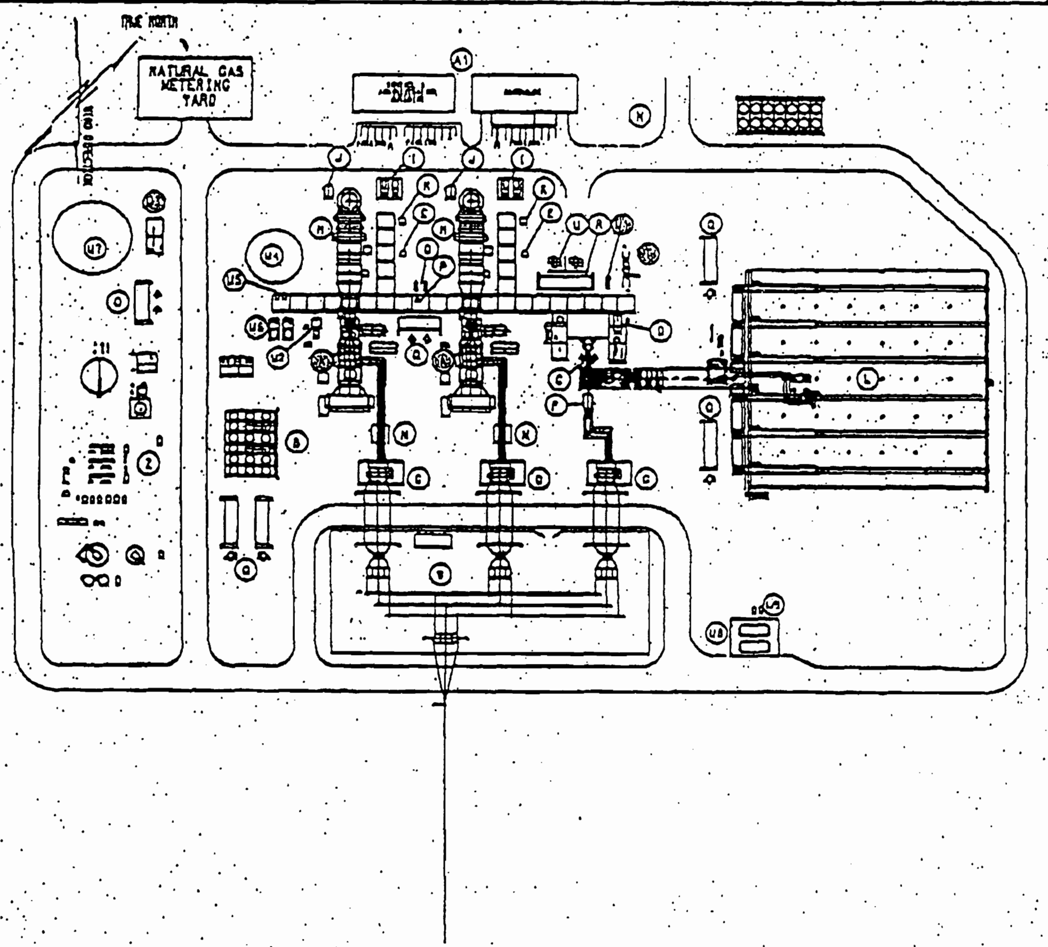
② Rd crosses horiz rd near development

36.109 -120.0486

FEDERAL POWER AVENAL, LLC

AVENAL ENERGY | **FIGURE 2.0-2**


PROPERTY LINE
TURNAROUND
GATE
SAN LUIS CANAL
STORM WATER EVAPORATION/PERCOLATION BASIN
A BOILER N.1,917,806 E.6,248,014
B HRSC STACK 1 N.1,917,734 E.6,247,873
C HRSC STACK 2 N.1,917,635 E.6,247,772
A ISSUED FOR REVIEW
FLUOR.
AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA
FIGURE 2.1-4
SITE PLAN
CONCEPTUAL DESIGN
A3DV01-1-SP-5-00-1



MAJOR EQUIPMENT LIST

A GAS TURBINE GENERATOR
B INLET AIR CHILLERS
C STEAM TURBINE
D STG LUBE OIL SKID
E HRSG BLOW DOWN DRUM
F STG GENERATOR
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 (4160 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

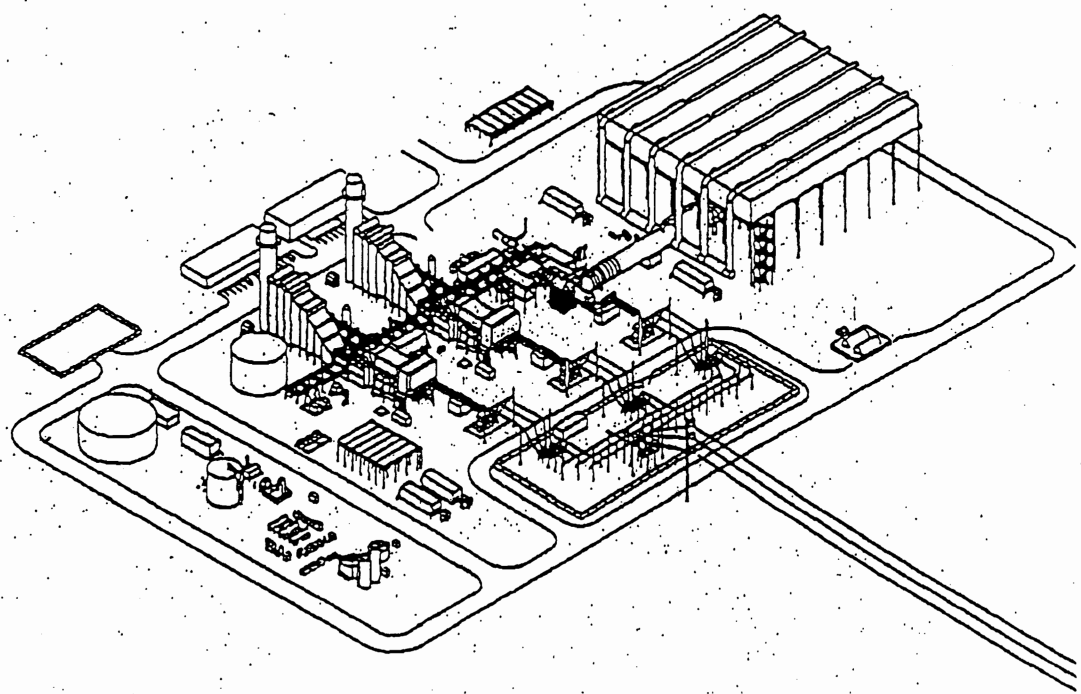
NO.	DATE	DESCRIPTION
A	[illegible]	ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

FIGURE 2.3-3
PLOT PLAN
CONCEPTUAL DESIGN

F-120' A3DY01-1-PP-0-00-1 A



REV	DATE	DESCRIPTION
A	[illegible]	ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

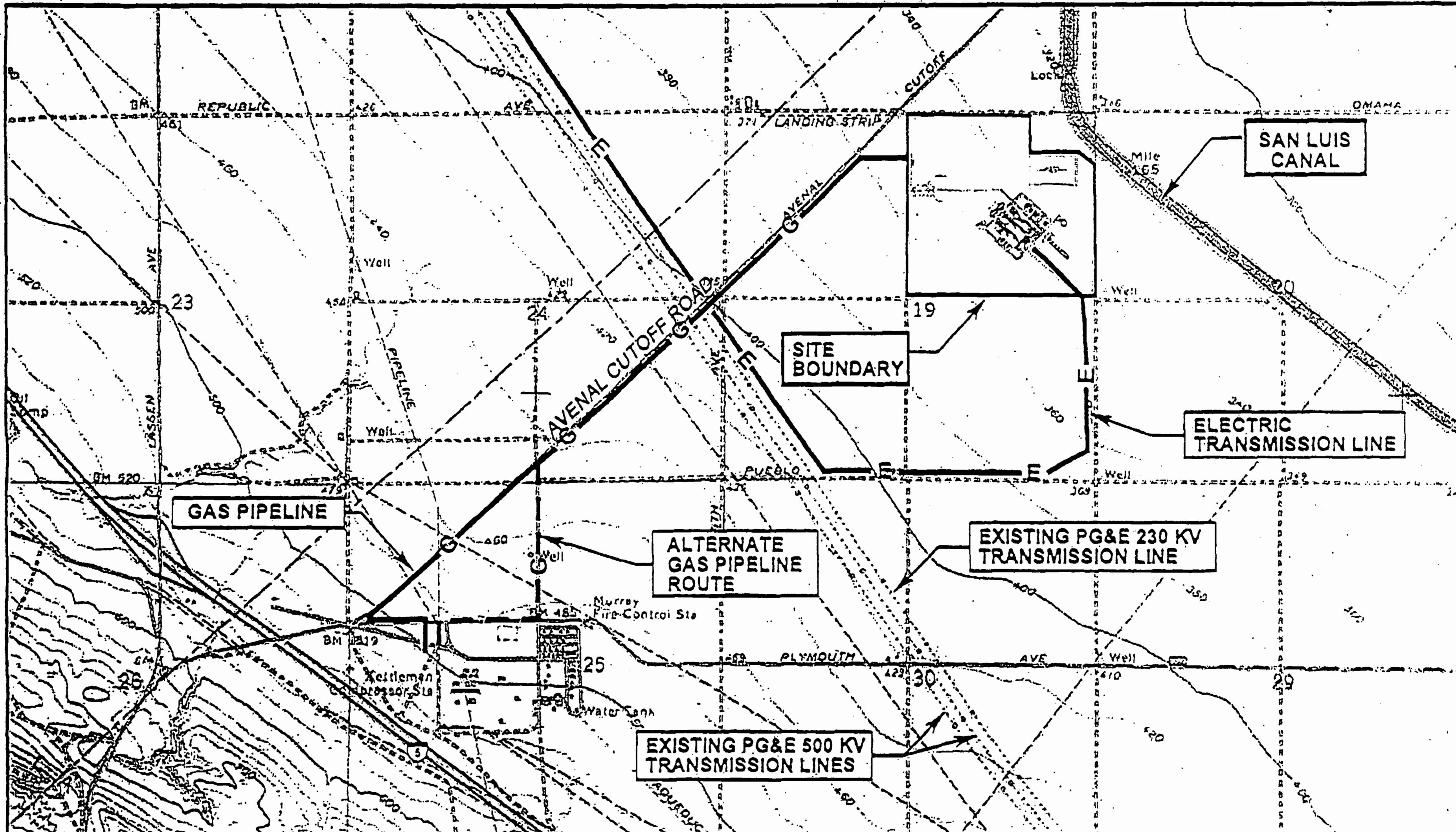
ISO VIEW
CONCEPTUAL DESIGN

SCALE: NONE

DRAWING NO.: A30Y01-1-PP-0-00-2

REV: A

290317-AFC-2.1-1A REV. 09/05/06



REFERENCE:
U.S.G.S 7.5 MINUTE TOPOGRAPHIC SERIES MAP OF LA CIMA, CALIFORNIA, DATED 1978.

0 2,000 4,000 FEET
SCALE

NATURAL GAS AND ELECTRICAL INTERCONNECTION ROUTES

FEDERAL POWER AVENAL LLC

AVENAL ENERGY | FIGURE 2.1-1A

ATTACHMENT D

CTG 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. PM_{10} and SO_2 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 189[25] 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

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[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
Avenal Energy Project

	Case 1	Case 5	Case 9	Case 2	Case 6	Case 10	Case 4	Case 8	Case 12
	101°F	63°F	32°F	101°F	63°F	32°F	101°F	63°F	32°F
	Full Load w/ DB[1]	Full Load w/ DB[1]	Full Load w/ DB[1]	Full Load no DB	Full Load no DB	Full Load no DB	50% Load	50% Load	50% Load
Ambient Temp, °F	101	63	32	101	63	32	101	63	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	359.5	144.1	168.8	183.2
STG Gross Power, MW	290.8	273.3	254.7	171.6	176.1	177.7	118.3	127.6	130.8
Plant Gross Power Output, MW	635.6	618.3	613.7	517.2	521.7	537.2	262.5	296.2	313.9
Plant Net Power Output, MW	600.0	600.0	600.0	483.7	506.5	525.5	250.3	286.3	304.8
GTs Fuel Flow, kpph	156.4	156.4	161.8	156.4	156.4	161.8	87.2	96.2	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	1,856.3	1,001.4	1,104.3	1,171.9
DBs Heat Input, MMBtu/hr (HHV)	562.3	454.4	356.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, MMBtu/hr (HHV)	2,356.5	2,248.8	2,211.8	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
Stack Flow, lb/hr	3,653,000	3,650,000	3,759,000	3,628,000	3,630,000	3,743,000	2,232,700	2,336,800	2,413,300
Stack Flow, acfm	1,044,365	1,025,495	1,069,836	1,051,631	1,037,822	1,071,653	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%	3.89%
H_2O	10.54%	10.03%	9.12%	8.39%	8.28%	7.78%	8.07%	7.97%	7.63%
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	16.06	13.03	13.03	13.47	7.26	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]	1.66	1.59	1.56	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	19.56	15.86	15.88	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	5.68	5.59	3.17	3.17	3.28	1.77	1.95	2.07
VOC, lb/MMBtu (HHV)[4]	0.0025	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	26.98	14.60	16.08	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)[6]	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
N_2O, lb/MMBtu (HHV)[6]	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
CO_2, lb/hr[8]	275,599	262,984	258,674	210,000	209,976	217,102	117,114	129,153	137,055
CH_4, lb/hr[8]	30.7	29.2	28.8	23.4	23.4	24.1	13.0	14.4	15.2
N_2O, lb/hr[8]	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 acf of the fuel is assumed to be converted to SO_2 with no SO_3 conversion.

4) Based on an assumption that 20% of reported UHC emissions are VOCs.

5) Includes front-half (filterable) portion only. Back-half (condensible) portion is excluded.

6) CH_4 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) CO_2 emission factor (kg/MMBtu) = 53.06

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Carbon Dioxide Emission Factors and Oxidation Rates for Stationary Combustion, August 10, 2007.

8) N_2O 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 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 s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried 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 s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried 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 s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried 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% O2 (Oxidation catalyst, or equal)	4.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	
NOx	2.5 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	
PM10	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel, or equal		
SOx	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmv @ 15% O2	1.5 ppmv @ 15% O2	

** 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 s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried 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-3953-10-1, -11-1, -12-1, -13-1, and –14-1)

Units C-3953-10-1 and –11-1 (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% O_2 (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% O_2 (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% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)
2. 2.5 ppmvd @ 15% O_2 (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% O_2 (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% O_2 (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% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). Therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

II. 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% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 1.5 ppmvd VOC @ 15% O_2

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% O_2
2. 2.0 ppmvd VOC @ 15% O_2

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% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 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% O_2. The facility has proposed to use natural gas fuel with emissions of less than or equal to 2.0 ppmv @ 15% O_2; therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} 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 in 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-3953-10-1 and –11-1 (Turbines)

IV. 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-3953-12-1 (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 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)

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 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)

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 NOx emissions from the boiler will not exceed 9.0 ppmv @ 3% O_2. 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% O_2. The facility has proposed NO_X emissions of less than 9.0 ppmv @ 3% O_2. Therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

II. 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-3953-12-1 (Boiler)

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} 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-3953-13-1 (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 NOx 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-3953-13-1 (Diesel IC engine powering fire water pump)

II. 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-3953-14-1 (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:

- ≥ 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. ≥ 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. ≥ 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 $\leq$ 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:

<u>NO_X (annual):</u>

$$\frac{2.8\ \cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 265\ lb\ NO_X/year$$

PE_{NOx} = 265 lb NO_X/year = 0.1325 tons NO_X/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:

<u>NO_X (annual):</u>

$$\frac{7.4\ \cancel{g}^{(1)}}{\cancel{hp\text{-}hr}} \times \frac{(1-0.9)}{1} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 70\ lb\ NO_X/year$$

PE_{NOx} = 70 lb NO_X/year = 0.035 tons NO_X/year

District BACT policy demonstrates how to calculate the cost effectiveness of alternate basic equipment or process:

$$CE_{alt} = (Cost_{alt} - Cost_{basic}) \div (Emission_{basic} - Emission_{alt})$$

[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:

$$\text{MCET (\$/yr)} = (E_{NOx} \times T_{NOx}) + (E_{CO} \times T_{CO}) + (E_{VOC} \times T_{VOC})$$

Where:
E_{NOx} = tons-NO_X controlled/yr
E_{CO} = tons-CO controlled/yr
E_{VOC} = tons-VOC controlled/yr
T_{NOx} = 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 ($Cost_{alt} - Cost_{basic}$), 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:

<u>CO (annual):</u>

$$\frac{1.83\ \cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 173\ \text{lb CO/year}$$

PE_{CO} = 173 lb CO/year = 0.0865 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:

<u>CO (annual):</u>

$$\frac{11.6\ \cancel{g}\ ^{(2)}}{\cancel{hp\text{-}hr}} \left| \frac{(1-0.8)}{1} \right| \frac{860\ \cancel{hp}}{1} \left| \frac{lb}{453.6\ \cancel{g}} \right| \frac{50\ \cancel{hr}}{year} = 220\ lb\ CO/year$$

PE_{CO} = 220 lb CO/year = 0.11 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:

<u>VOC (annual):</u>

$$\frac{0.39\ \cancel{g}}{\cancel{hp\text{-}hr}} \left| \frac{860\ \cancel{hp}}{1} \right| \frac{lb}{453.6\ \cancel{g}} \left| \frac{50\ \cancel{hr}}{year} \right. = 37\ lb\ VOC/year$$

PE_{VOC} = 37 lb VOC/year = 0.0185 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 ≥ 50% can be calculated as:

<u>VOC (annual):</u>

$$\frac{0.10\ \cancel{g}\ ^{(3)}}{\cancel{hp\text{-}hr}} \left| \frac{(1-0.5)}{1} \right| \frac{860\ \cancel{hp}}{1} \left| \frac{lb}{453.6\ \cancel{g}} \right| \frac{50\ \cancel{hr}}{year} = 5\ lb\ VOC/year$$

PE_{VOC} = 5 lb VOC/year = 0.0025 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_{NOx} = 0.1325 tpy – 0.035 tpy = 0.0975 tpy
E_{VOC} = 0.0185 tpy – 0.0025 tpy = 0.016 tpy

MCET ($/yr) = (0.0975 x $9,700) + (0.016 x $5,000) = $1,026/year

As presented above, ($Cost_{alt}$ – $Cost_{basic}$) 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 NOx 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 - <u>Select BACT</u>

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-3953-14-1 (Natural gas IC engine powering electrical generator)

II. 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:

- ≥ 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. ≥ 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 - <u>Select BACT</u>

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 Unified Air Pollution Control District

MEMORANDUM

DATE: June 14, 2014

TO: Derek Fukuda, AQE—Permit Services

FROM: Leland Villalvazo, SAQS—Technical Services

SUBJECT: Revised NO_2 1-hour NAAQA Assessment for Avenal Power Center

Technical Services was requested to revise the RMR and AAQA assessment performed for project C-1011324, dated June 25, 2002, to lower the NOx and CO annual emission levels.

A review of the previous project indicated that the major item of concern was the 1-hour standard for NO_2. The previous assessment was based on the State standard of 339 ug/m^3 whereas the new federal standard 188.68 ug/m^3. The assessment contained in this memo will primarily address the new federal NO_2 NAAQS and any updates needed to the previous RMR assessment.

Background:
EPA has revised the primary NO_2 NAAQS in order to provide requisite protection of public health. Specifically, EPA has established a new 1-hour standard at a level of 100 ppb (188.68 ug/m^3), based on the 3-year average of the annual 98th percentile of the daily maximum 1-hour concentrations, to supplement the existing annual standard. EPA has also established requirements for NO_2 monitoring network that will include monitors at locations where maximum NO_2 concentrations are expected to occur, including within 50 meters of major roadways, as well as monitors sited to measure the area-wide NO_2 concentrations that occur more broadly across communities.

The final rule was signed on January 22, 2010. The effective date of the new 1 hour standard is 60 days after the final rule has been published in the Federal Register. The final rule was published in the Federal Register on Feb 9, 2010. The effective date is April 12, 2010.

Results:
Based on guidance from EPA dated February 25, 2010, the District has updated the AAQA assessment to include the new NO_2 1-hour standard, see below. The results follow the procedure outlined in the District's interim draft guidance document entitled "Modeling Procedure to Address The New Federal 1 Hour NO_2 Standard".

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	**P**	13.58
Tier IV	**140.37**		140.37	188.68	**P**	48.31

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	**P**	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia

Conclusion

Based on the updated RMR, the risk from this facility is less than 10 in one million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed below must be included for the proposed unit(s).

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.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

Conditions

1. PM_{10} emission rate shall not exceed **0.059 g/HP-hr (note method) for the 288 hp engine** (C-3953-13-1).

2. The 860 hp engine (C-3953-14-1) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **50 hours per year**.

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	P	13.58
Tier IV	**140.37**		140.37	188.68	P	48.31

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	P	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia

Diesel I.C. Engines (DICE)
Screening Risk Tool

Project Information

Region: C   Facility ID: 3953   Unit #: 13-1

Project #: 110751

Date: 7/14/2010

Met Station

District	SJVAPCD
Met Site	HANFORD
Model Type	RURAL
Year:	2008

Engine Data

BHP:	288
% Load:	100
PM10 EF (g/BHP):	0.059
Hours / Yr:	100
Lbs / Yr:	3.75

Convert to G/BHP

Convert to G/KW

Update Emissions

Receptor Data

Quad: QUAD 1

Distance(m): 50

Miles: Feet:

Yards: 10th Mi:

NW N NE

W Quad 4 Quad 1 E

Quad 3 Quad 2

SW S SE

Cancer Risk

	Resident Risk:	Maximum Res. Risk
In a Million	**0.24**	**1.98**
Worker Adjustment Factor %		37.91
	Worker Risk:	**Maximum Worker Risk**
In a Million	**0.09**	**0.75**

Quad: 2

Distance: 50

Calculate Risk

Print Form

New   **View Eng Data**   **SAVE**   **Close Form**

14-1

Print Worksheet

INTERNAL COMBUSTION (NG)
EMISSION FACTORS
(LBS. / MMCF)

FACILITY NAME:
DATE:

Priority Score 0.092999134

Receptor Distance: 1206

Total hrs. of operation 50.00 | MMCF/HR 0.0071 | MMCF/YR 0.36

POLLUTANT	EMISSION FACTOR (MMCF/HR) <1000	>1000	TURBINE	Acute REL	Chronic REL	Cancer URF
Acetaldehyde	0.944	1.1328	0.037	0	9	2.70E-06
Acrolein	0.3783	0.454	0.009	0.19	2.00E-02	0
Benzene	3.257	3.9084	0.0113	1300	71	2.90E-05
Formaldehyde	32.4963	38.9956	0.094	94	3.6	6.00E-06
Naphthalene	0.1785	0.1785	0.0008	0	14	0
PAH's	0.0179	0.0179	0.0002	0		1.70E-03
Propylene	16.2259	19.4711	1.0522	0	0	0
Toluene	1.1145	1.3374	0.0726	37000	200	0
Xylenes	0.4048	0.4858	0.0289	22000	300	0
Ethyl Benzene	0.3257	0.3908	0.0132	0	0	0
Hexane	0.7491	0.8989	1.75	0	0	0

	<1000 EMISSION FACTORS	LBS./HR.	G/SEC	LBS./YR.	G/SEC	Acute Score	Chronic Score	Carcinogenic Score	Non-Carcinogenic Score
Acetaldehyde	0.944	6.70E-03	**8.45E-04**	3.35E-01	**4.82E-06**	0	0.11170667	0.001538201	0.111706667
Acrolein	0.3783	2.69E-03	**3.39E-04**	1.34E-01	**1.93E-06**	21.204711	20.144475	0	21.20471053
Benzene	3.257	2.31E-02	**2.92E-03**	1.16E+00	**1.66E-05**	0.0266823	0.048855	0.057002386	0.048855
Formaldehyde	32.4963	2.31E-01	**2.91E-02**	1.15E+01	**1.66E-04**	3.6817616	9.61348875	0.117669102	9.61348875
Naphthalene	0.1785	1.27E-03	**1.60E-04**	6.34E-02	**9.12E-07**	0	0.01357875	0	0.01357875
PAH's	0.0179	1.27E-04	**1.60E-05**	6.35E-03	**9.15E-08**	0	0	0.018364505	0
Propylene	16.2259	1.15E-01	**1.45E-02**	5.76E+00	**8.29E-05**	0	0	0	0
Toluene	1.1145	7.91E-03	**9.98E-04**	3.96E-01	**5.70E-06**	0.0003208	0.00593471	0	0.005934713
Xylenes	0.4048	2.87E-03	**3.62E-04**	1.44E-01	**2.07E-06**	0.000196	0.00143704	0	0.00143704
Ethyl Benzene	0.3257	2.31E-03	**2.92E-04**	1.16E-01	**1.66E-06**	0	0	0	0
Hexane	0.7491	5.32E-03	**6.71E-04**	2.66E-01	**3.83E-06**	0	0	0	0

San Joaquin Valley Unified Air Pollution Control District

MEMORANDUM

DATE: June 25, 2002

TO: Errol Villegas, SAQE—Permit Services

FROM: Esteban Gutierrez, AQS—Technical Services

SUBJECT: AAQA and RMR Modeling request for Duke energy Avenal LLC.

As per your request, Technical Service performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR for, two turbines, two IC engines, nineteen (19) cooling towers and a boiler for a power plant. The engineer supplied the maximum fuel rate as well as process rates for all of the units described above. ISCST3 model was used to determine dispersion value for cancer risk exposure.

The results from the RMR modeling runs and Criteria Pollutant Modeling are as follows:

RMR Modeling Results

REFINED HRA SUMMARY			
Device	**(2) Turbines**	**Boiler**	**(3) 4 cell tower**
Fuel	**NG**	**NG**	
Prioritization Score	0.8242	.0107	N/A
Cancer Risk	N/A	N/A	N/A
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
TBACT Required?	No	No	No

REFINED HRA SUMMARY			
Device	**7 cell tower**	**300 Hp ICE**	**660 HP ICE**
Fuel		**Diesel**	**Diesel**
Prioritization Score	N/A	N/A	N/A
Cancer Risk	N/A	2.01E-6	1.00E-6
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
Maximum operating Hrs		200	38
TBACT Required?	No	Yes	No

Criteria Pollutant Modeling Results*

Values are in ug/m^3

	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	Pass**	Pass**

*Results were taken from the attached PSD spreadsheet.
**The criteria pollutants noted by a double asterisk (**) are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2). Operating time for 24 hour risk was adjusted for PM10 levels.
*** Passing score was obtained from running OLM (Ozone Limiting Method.)

(2) NG Turbines Stack Parameters			
Source Type	Point	**Process Rate (T1) MMbtu/yr**	16,958,390
Stack Height (m)	44.2	**Process Rate (T2) MMbtu/yr**	20,582,010
Stack Diam. (m)	5.49	**Hours of operation yr (T1)**	8400
Gas Exit Velocity (m/sec) T1	20.4	**Hours of operation yr (T2)**	8760
Stack Gas Temp (°K)	356	**Receptor Distance (m)**	1609
Location Type	Rural		

7 Cell Cooling Tower Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	13.7	**Process Rate Gal/Yr**	57,153,744,000
Stack Diam. (m)	9.64	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	8.10	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

(3) 4 Cell Cooling Towers Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	16.08	**Process Rate Gal/Yr**	5,308,560,000
Stack Diam. (m)	3.57	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	11.46	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

Boiler Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	11.28	**Process Rate MMbtu/yr**	93,500
Stack Diam. (m)	0.812	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	12.2	**Hours of operation**	2500
Stack Gas Temp (°K)	476		

Diesel Engine (300 Hp)			
Source Type	Point	**Closest Receptor (m)**	1609
Stack Height (m)	3.04	**Location Type**	RURAL
Stack Diam. (m)	0.13	**Max Operating (hr/yr)**	**100**
Gas Exit Velocity (m/sec)	67.1	**Fuel Type**	Diesel
Stack Gas Temp (°K)	716	**PM10 g/bhp-hr**	0.09

Diesel Engine (660 Hp)			
Source Type	Point	**Closest Receptor (m)**	1609
Stack Height (m)	3.04	**Location Type**	RURAL
Stack Diam. (m)	0.23	**Max Operating (hr/yr)**	**38**
Gas Exit Velocity (m/sec)	45.0	**Fuel Type**	Diesel
Stack Gas Temp (°K)	799	**PM10 g/bhp-hr**	0.4

Conclusion:

The Criteria modeling runs indicate that the emissions from the proposed equipment will not have an adverse impact on the State and National AAQS. Therefore, no further modeling will be required to demonstrate that the AAQS or EPA's level of significance would be exceeded.

The carcinogenic risk for the 300 hp engine is 2.01E-06, which is below the maximum allowable risk of 10 in a million for diesel IC engines emitting ≤ 0.149g PM_{10}/bhp/hr. The risk for the 660 hp engine is 1.00E-06 which is the allowable risk of one in a million for engines emitting > 0.149g PM_{10}/bhp/hr. Therefore, **the project is approved for permitting, and TBACT is required for the 300 hp engine.** In order to assure compliance with the assumptions made for the risk management review the following conditions listed on the PTO are required:

1. Only CARB certified fuel containing not more than 0.05% sulfur by weight is to be used in these engines.

2. PM_{10} emission rate shall not exceed **0.09 g/HP-hr (note method) for the 300 hp engine** (C-3953-8-0).

3. PM_{10} emission rate shall not exceed **0.40 g/HP-hr (note method) for the 660 hp engine** (C-3953-9-0).

4. The exhaust stacks shall not be fitted with a rain caps, or any other similar devices, that impedes vertical exhaust flow.

5. The 300 hp engine (C-3953-8-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **100 hours per year**.

6. The 660 hp engine (C-3953-9-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **38 hours per year**.

7. The 660 hp engine (C-3953-9-0) shall not operate more than **7 hours in any rolling 24 hr period during maintenance, testing, and required regulatory purposes.**

ATTACHMENT H

SO_X for PM_{10} Interpollutant Offset Analysis

SO_X for PM_{10} Interpollutant Offset Analysis
Avenal Power Center, LLC

Facility Name:	Avenal Power Center, LLC	Date:	June 30, 2010
Mailing Address:	500 Dallas Street. Level 31 Houston, TX 77002	Engineer: Lead Engineer:	Derek Fukuda Joven Refuerzo
Contact Person:	Jim Rexroad		
Telephone:	(713) 275-6147		
Application #:	C-3953-10-1, -11-1, -12-1, -13-1, and -14-1		
Project #:	C-1100751		
Location:	NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032		
Complete:	March 18, 2010		

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.

In addition, Avenal Power Center, LLC has proposed to limit the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year.

Facility C-3953 will become a major source for NO_X, VOC, and PM_{10}. There will be an increase in emissions for all pollutants and offsets are required for NO_X, VOC, and PM_{10} 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% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
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))
PM_{10}: 0.0107 lb/MMBtu

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 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 stream. 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-3953-10-1: 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-3953-11-1: 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-3953-12-1: 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-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

V. Interpollutant Offset Ratio Proposal SO_X for PM_{10}

Rule 2201, New and Modified Stationary Source Review, specifically allows the use of PM_{10} precursor ERCs to offset PM_{10} 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-PM_{10} relationship given the atmospheric chemistry and the meteorology of the locale).

The SO_X for PM_{10} 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 x 1.5 = 1.5:1 is valid for project C-1100751.

IV. Project Offset Calculations

i. C-3953-10-1 and C-3953-11-1 (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 NOx 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(1)	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 PM_{10}, 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 PM_{10}, 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:

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

[1] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

SO_X EF = (0.36 ~~gr-S~~/100 ~~dscf~~) x (1 ~~lb-S~~/7000 ~~gr~~) x (64 lb SO_X/32 ~~lb-S~~) x (1 ~~scf~~/1013 ~~Btu~~) x (10^6 ~~Btu~~/MMBtu)
= 0.001 lb-SO_X/MMBtu

CTG w/o Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **1.86 lb-SO_X/hr**

CTG w/ Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **2.36 lb-SO_X/hr**

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 PM_{10}, 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 PM_{10}, 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	197,928 lb/year	Facility Wide Limit
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 PM_{10} potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) $*$ (4 qtr/year)
= **58 lb PM_{10}/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)
PM_{10}	0.19	2.2	58	233

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

The PM_{10} emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.059 g/hp·hr) $*$ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) $*$ (288 hp) ÷ (453.6 g/lb) $*$ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) $*$ (288 hp) ÷ (453.6 g/lb) $*$ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) $*$ (288 hp) ÷ (453.6 g/lb) $*$ (50 hr/year)
= **1.9 lb PM_{10}/year**

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 PM_{10} emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.034 g/hp·hr) $*$ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

$= (0.034\ g/hp \cdot hr) * (860\ hp) \div (453.6\ g/lb) * (24\ hr/day)$
$=$ **1.5 lb PM_{10}/day**

$= (0.034\ g/hp \cdot hr) * (860\ hp) \div (453.6\ g/lb) * (12.5\ hr/qtr)$
$=$ **1 lb PM_{10}/qtr**

$= (0.034\ g/hp \cdot hr) * (860\ hp) \div (453.6\ g/lb) * (50\ hr/year)$
$=$ **3 lb PM_{10}/year**

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-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
C-3953-13-1			12	2	0	0
C-3953-14-1			31	3	1	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

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-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,179**	**161,545**	**33,520**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

Offset Calculations:

PM_{10}:

SSPE2 (PM_{10}) = 161,545 lb/year
Offset threshold (PM_{10}) = 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):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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 PM_{10} 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):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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 PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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 PM_{10} offset requirements

The applicant states either PM_{10} 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 PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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 PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} 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 PM_{10} 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).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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
1st qtr. ERCs applied to 2nd 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 PM_{10} emissions increases associated with this project.

V. Conclusion

Approve use of an overall SO_X for PM_{10} interpollutant offset ratio of 1.5:1 (1.000 x 1.5).

VI. Recommendation

Compliance with all applicable rules and regulations is expected. Issue Authorities to Construct C-3953-10-1, -11-1, -12-1, -13-1, and -14-1 with a SO_X for PM_{10} interpollutant offset ratio of 1.000:1.

Appendix

A: District Review and Approval

Appendix A

District Review and Approval

Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

DEVELOPMENT OF THE INTERPOLLUTANT RATIO

For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

March 2009

Introduction

Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to "offset" the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

Analyses included in Interpollutant evaluation

Factors Considered

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

Elements from 2008 PM 2.5 Plan

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

Extension by additional analysis

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

Strengths

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

Limitations

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

Analyses contained in Receptor modeling

Factors Considered

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

Analyses in receptor modeling that use input from regional modeling

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

Extension by additional analysis

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

Strengths

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

Limitations

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

Analyses contained in Regional modeling

Factors Considered

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

Extension by additional analysis

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

Strengths

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

Limitations

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

Results and Documentation

SJVAPCD Interpollutant Ratio Results

SOx for PM ratio: 1.000 ton of SOx per ton of PM

NOx for PM ratio: 2.629 tons of NOx per ton of PM

These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

Interpollutant Ratio Issues & Documentation

	TOPIC	Reference
1	**Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions.	2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2
2	**Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites.	*DV Qtrs*
3	**Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties.	*Q4 Model Pivot, Model-site chem, Model-Daily Q4*
4	**Reason for using combined results of receptor and regional model:** Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM.	2008 PM2.5 Plan, Appendix F
	Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis.	2008 PM2.5 Plan, Appendix G
5	**Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources.	2008 PM2.5 Plan, Appendix F
6	**Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods.	2008 PM2.5 Plan, Appendix G
7	**Common area of influence adjustments used for all receptor evaluations:** Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2) Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3) Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2) Marine emissions not found present in CMB modeling for this analysis.	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
8	**Variations to reflect secondary area of influence specific to location:** Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2)	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
9	**Reasons for using 2009 Interpollutant Ratio Projection:** 2009 Interpollutant ratio is consistent with current emissions inventories	2008 PM2.5 Plan
	Regional modeling does not show a significant change in chemical relationships through 2014.	*Q4 Model Pivot*
10	**Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets.	District Rule 2201 Section 4.13.3

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)[i,j]	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

	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

Parts Per Million Volume -> Grams/Brake Horsepower - Hour

ppmv -> g/Bhp-hr

Variables:		
Engine Size:	860	hp
NO_x:	230	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH_4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
$MW_{(NOx)}$:	46	as NO_2
$MW_{(CO)}$:	28	
$MW_{(VOC)}$:	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

$$\frac{ppmv}{1} \cdot \frac{\text{F-factor}}{1} \cdot \frac{MW_{pollutant}}{1} \cdot \frac{20.9}{(20.9 - O_2\%)} \cdot \frac{1}{\text{Conversion \#1}} \cdot \frac{1}{\text{Conversion \#2}} \cdot \frac{\text{Conversion \#3}}{1} \cdot \frac{1}{\text{Engine Eff.}} =$$

for NOx

$$\frac{230\ \cancel{parts}}{10^6\ \cancel{parts}} \cdot \frac{8578\ \cancel{dscf}}{\cancel{MMBtu}} \cdot \frac{46\ \cancel{lb}}{\cancel{1\ lb\text{-}mol}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{1\ lb\text{-}mol}}{379.5\ \cancel{dscf}} \cdot \frac{\cancel{MMBtu}}{393.24\ bhp\text{-}hr} \cdot \frac{453.59\ g}{\cancel{lb}} \cdot \frac{1}{35\%} =$$

= 2.750 g/bhp-hr | 2365 g/hr | 5.21465 lbs/hr | 125 lbs/day

for CO

$$\frac{0\ \cancel{parts}}{10^6\ \cancel{parts}} \cdot \frac{8578\ \cancel{dscf}}{\cancel{MMBtu}} \cdot \frac{28\ \cancel{lb}}{\cancel{1\ lb\text{-}mol}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{lb}}{379.5\ \cancel{dscf}} \cdot \frac{\cancel{MMBtu}}{393.24\ bhp\text{-}hr} \cdot \frac{453.59\ g}{\cancel{lb}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC

$$\frac{0\ \cancel{parts}}{10^6\ \cancel{parts}} \cdot \frac{8578\ \cancel{dscf}}{\cancel{MMBtu}} \cdot \frac{16\ \cancel{lb}}{\cancel{1\ lb\text{-}mol}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{lb}}{379.5\ \cancel{dscf}} \cdot \frac{\cancel{MMBtu}}{393.24\ bhp\text{-}hr} \cdot \frac{453.59\ g}{\cancel{lb}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

	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

Parts Per Million Volume --> Grams/Brake Horsepower - Hour

ppmv --> g/Bhp-hr

Variables:

Engine Size:	860	hp
NO_x:	616	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH_4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:

Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
$MW_{(NOx)}$:	46	as NO_2
$MW_{(CO)}$:	28	
$MW_{(VOC)}$:	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

$$\frac{\text{ppmv}}{1} \cdot \frac{\text{F-factor}}{1} \cdot \frac{MW_{pollutant}}{1} \cdot \frac{20.9}{(20.9 - O_2\%)} \cdot \frac{1}{\text{Conversion \#1}} \cdot \frac{1}{\text{Conversion \#2}} \cdot \frac{\text{Conversion \#3}}{1} \cdot \frac{1}{\text{Engine Eff.}} =$$

for NOx:

$$\frac{616\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{46\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{1\ \text{lb-mol}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 7.365 g/bhp-hr | 6334 g/hr | 13.9662 lbs/hr | 335 lbs/day

for CO:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{28\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{16\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

Avenal Power Center, LLC
500 Dallas Street, Level 31
Houston, TX 77002

RECEIVED
JUL 0 3 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

7/1/08
Dated

Joseph Forbes
Senior Lawyer

ATTACHMENT J

EPA Comments and District Responses

EPA Comments / District Response

The comments (from Gerardo Rios) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

EPA Comments – Letters Dated September 13, 2010

EPA Comment #1:

Applicable federal requirements include thresholds for defining a major source of criteria pollutant emissions. For those sources where emission estimates and/or emission limits are relatively close to the federal thresholds, EPA encourages the following: (a) refinement of emissions and compliance demonstration methods that would ensure the thresholds would not be exceeded, and/or (b) a 5-10% buffer between the permitted emission limits and the federal threshold.

The proposed annual NOx emission and CO emission limits are within a margin of less than 5% of the federal annual threshold limit for defining a new major stationary source under the Federal Prevention of Significant Deterioration (PSD) permit program. The threshold is 100 tons per year (tpy) each. If the limits of these pollutants are relaxed, the facility may be subject to the applicable federal requirements, such as the Federal Prevention of Significant Deterioration (PSD) permitting program (See 40 CFR Part 52.21 (r)(4)).

District's Response:

The permitted emissions from this facility are below PSD thresholds. The facility's NO_X and CO emissions limits are included as permit conditions on the PDOC. The facility is also required to maintain records to demonstrate that they do not exceed these emission limits.

In addition, emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

EPA Comment #2:

In the "General Calculations" section (See PDOC Page 27, Section VII. C. 5), the District compares the annual emission estimates for regulated pollutants to the major source threshold to determine whether a pollutant is subject to major source requirements for NO_X, CO, VOC, PM_{10}, and SO_X emissions. However,

$PM_{2.5}$, which also is a regulated pollutant, is not included. On May 8, 2008 EPA finalized regulations to implement the NSR program for $PM_{2.5}$. A source that emits or has the potential to emit 100 tpy or more PM2.5 in a nonattainment area is defined as a major stationary source. (Reference 40 CFR Part 51, Appendix S.) We recommend the District include in its evaluation the $PM_{2.5}$ emission estimates with a comparison to the federal nonattainment major source threshold of 100 tpy (or 200,000 pounds per year).

District's Response:

The potential emissions of PM_{10} from the facility are 161,552 lb-PM_{10}/year (Calculated in the PDOC). Using the conservative assumption that all PM_{10} is $PM_{2.5}$, it is clear that the $PM_{2.5}$ emissions from this facility will not exceed the major source threshold of 100 tons/year. However, to avoid any confusion, the District will revise the PDOC to discuss the potential emissions of $PM_{2.5}$ from this operation.

EPA Comment #3:

The proposed annual emissions (calculated on a twelve consecutive month rolling basis) from the facility are 198,840 pounds per year (lb/yr) NO_X and 197,928 lb/year CO. (See PDOC Page 27, Section VII. C. 5) These annual emissions are equivalent to 99.4 tpy of NO_X emissions and 98.9 tpy of CO emissions, both of which are relatively close to the federal PSD permit program applicability threshold of 100 tpy for each ofthese pollutants. A proposed permit condition requiring that annual emissions not exceed these levels has been added to all combustion related equipment. The condition reads as follows:

> *"Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NOx (as N02) -198,840 lb/year; CO -197,928lb/year."*

In a review of the post-project potential to emit annual emission estimates in Sections VII.C.2.i through C.2.iv. (See PDOC Pages 16-26) for each piece of equipment, we noted that the combustion turbine operations contribute the majority of NOx and CO emissions.

Based on discussions with the District, we understand that in addition to the 12-month rolling facility NOx and CO emission limits that are equivalent to 99.4 tpy and 98.9, respectively, the District has made no other changes to the current FDOC permit conditions. These conditions include, but are not limited to, the following: continuous emissions monitoring of NO_X and CO; compilation of emissions on a daily, monthly, 12 consecutive month rolling average, and annual basis; quarterly reporting of excess emissions; and acid rain (40 CFR Part 75) compliance requirements.

At this time, it appears the proposed requirements provide practically and federally enforceable conditions based on our understanding of the proposed revision. However, given that the NO_X permit limit is within less than 1% of the PSD permit threshold and the CO limit is within 1.1% of the PSD permit threshold, we suggest that the District consider requiring Avenal to report more frequently emissions as the actual emissions approach or exceed 90% of the 12-consecutive month rolling average permit limit to assure the 100 tpy threshold is not exceeded.

District's Response:

Emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

EPA Comment #4:

The District concludes on pp. 53-54 of the PDOC that the proposed project will not cause a violation of an air quality standard for NOx, and refers to Appendix G. PDOC Appendix G contains some additional detail on the air quality impact analysis for the l-hour N02 NAAQS, effective April 12, 2010, and states that "the emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS." The following are our comments specific to PDOC Appendix G:

a. SIP-Approved Rule 2201 -The District's approved SIP, in District Rule 2201, Section 4.14.1, provides that modeling used for purposes of determining whether a new or modified stationary source's emissions will cause or make worse the violation of an Ambient Air Quality Standard shall be consistent with the requirements contained in the most recent edition of EPA's "Guideline on Air Quality Models." This EPA guideline is found in 40 CFR Part 51, Appendix w. EPA recently has had occasion to review and comment on the applicant's l-hour N02 NAAQS analysis for the project in the context of the applicant's pending PSD permit application before EPA.

   We recognize that certain aspects of the project for which Avenal seeks a minor source permit vary from the project for which it seeks a PSD permit, in particular, the proposed addition of a facility-wide NOx emissions limit of the equivalent of approximately 99.4 tons per year (tpy) to the minor source permit. However, given that the equipment emitting NOx from the two projects has the same permitted hourly emission rates, many of the comments EPA made concerning consistency with 40 CFR Part 51, Appendix W in reviewing the applicant's l-hour N02 NAAQS analysis for PSD purposes may be relevant to the l-hour N02 NAAQS analysis for this minor source permit as well. We have attached for your consideration our comments dated June 15, 2010 and August 12, 2010 on the l-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes. We would be happy to discuss any issues or questions you may have concerning these comments.

b. EPA Guidance Memorandum -We also note that EPA recently issued guidance relating to modeling for the l-hour N02 NAAQS, with a cover memorandum entitled *Guidance Concerning Implementation of the 1-hour N02 NAAQS for the Prevention of Significant Deterioration Program,* dated June 29, 2010, that included two attached guidance documents, one of which was entitled *Applicability of Appendix W Modeling Guidance for the 1-hour N02 National Ambient Air Quality Standard,* dated June 28, 2010. We understand that the District is aware of this guidance, and we encourage the District to refer to this guidance for further detail on this subject.

c. Assumptions and Decision-making Process -The District's rationale in Appendix G for its conclusion that the project's emissions will not cause or contribute significantly to a violation of the l-hour N02 NAAQS is not clear from the documents provided. For example, the table addressing "Operational" scenarios on page 2 of Appendix G indicates that Tier 1 and Tier 2 impacts are each greater than the N02 NAAQS limit, while Tier III and Tier IV impacts are each below the N02 NAAQS limit. Furthermore, it is unclear how the modeling analysis meets the requirements of Appendix W (See Comment 4.a.) or whether the District intended to follow those requirements for the proposed permit revision. We recommend that the District provide a discussion of which Tier the District is relying upon to support its conclusion, the basis for selecting that Tier, and the modeling inputs, assumptions, etc. for that Tier.

<u>District's Response:</u>

a. *The District has reviewed your comments dated June 15, 2010 and August 12, 2010 on the 1-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes, and has no comments at this time. We did not use Avenal Power's analysis to make determinations of NAAQS impacts, but used our own guidance to perform the NO2 modeling (please see responses below).*
b. *The District has reviewed the documents stated above and developed a modeling guidance to address EPA's memos that were provided to the modelers at EPA Region 9. The District is currently waiting for EPA's*

response to this guidance, and is, in fact, working with EPA, ARB, and CAPCOA on developing statewide policy on how to implement our guidance, or something similar. The Avenal Power project was analyzed under this guidance, and the project was approved under Tier III of that guidance.

c. *The District uses a tiered approach when determining compliance with any NAAQS. This approach is similar to that required by OAQPS in their memos which require that each progressively more accurate tier be used (Tier I-Complete Conversion, Tier II-NO2 Ration and Tier III-OLM) until compliance is demonstrated. This project was approved under Tier III. We believe our guidance is consistence with EPA modeling practices and direction, and as we have stated above, we are patiently awaiting EPA's input on our guidance.*

EPA Comment #5, Joint letter to District and Avenal Power Center, LLC:

Avenal Power Center, LLC (Avenal) recently applied for a minor source New Source Review (NSR) permit from the San Joaquin Valley Pollution Control District (SJVAPCD or District) for the Avenal Energy Project. This permit seeks authority to construct the project with emissions limits below the major source thresholds triggering Clean Air Act (CAA) prevention of significant deterioration (PSD) preconstruction review. On July 28, 2010, SJVAPCD's public notice announcing its Preliminary Determination of Compliance for this minor source permit application was published in the Fresno Bee, triggering a public review and comment period for the proposed permit.

Concurrently, Avenal is seeking a PSD permit from EPA Region 9 for essentially the same project, but with greater emissions exceeding the major source threshold and thereby triggering PSD preconstruction review. The applicant's simultaneous application for both a minor source permit and a major souce PSD permit for the project raises a potential concern about circumvention of PSD preconstruction requirements.

EPA guidance on this subject states:

> Parts C and D of the Clean Air Act exhibit Congress's clear intent that new major sources of air pollution be subject to preconstruction review. The purposes for these programs cannot be served without this essential element. Therefore, attempts to expedite construction by securing minor source status through receipt of operational restrictions from which the source intends to free itself shortly after operation are to be treated as circumvention of the preconstruction review requirements... If a major source or major modification permit application is filed simultaneously with or at approximately the same time as the minor source construction permit, this is strong evidence of an intent to circumvent the requirements of preconstruction review.

Guidance on Limiting Potential to Emit in New Source Permitting, Terrell E. Hunt and John S. Seitz, dated June 13, 1989, at pp. 13-14.

We recommend that the applicant carefully review the guidance quoted above and other applicable EPA guidance on this topic prior to commencing construction of the project under the minor source permit, should that permit be finalized by the SJVAPCD.

District's Response:

The District disagrees that if Avenal were to construct under a California Energy Commission license that incorporates this minor source Determination of Compliance (DOC), it would be circumvention of the PSD preconstruction review.

Circumvention might occur if a source obtained a minor source permit and soon thereafter sought a PSD permit due to a small increase in emissions, and not as a new source. In this case, Avenal has applied for a PSD permit as a new source. If they construct as a minor source and don't receive a PSD permit, they will have to continue to comply with the minor source limits. However, constructing as a minor source and then obtaining a PSD permit as a new major source and operating in accordance with that PSD permit cannot be viewed as circumvention. Therefore, the EPA process, not the District's minor source permitting process, will determine whether circumvention will occur, and circumvention will not occur if EPA requires a PSD permit if Avenal pursues a permit with emissions above the PSD triggers.

ATTACHMENT K

Green Action Comments and District Responses

Greenaction Comments / District Response

The comments (from Bradley Angel) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Greenaction Comments – Letter Dated September 11, 2010

<u>Greenaction Comment #1:</u>

The Air District failed to conduct a proper and thorough public notice and public participation process. The failure to conduct proper notice and participation processes to the mostly low-income, Latino and Spanish-speaking residents of the nearest communities (Avenal, Huron and Kettleman City) violated the Air District's own environmental justice policy. The Air District's claim that you met your agency's required notice and participation mandates is insufficient as your own environmental justice policy commits the agency to uphold environmental justice.

Failing to notify residents or their organizations, failing to hold a public hearing and failing to provide Spanish-speaking residents equal time to comment as English speakers is a violation of environmental justice and civil rights policies and laws.

We are surprised and disappointed that the Air District would only translate information into Spanish following concerns being raised by Greenaction, and after the comment period already began. On August 20, 2010, we received an email from Dave Warner of the Air District that stated:

> Bradley,
>
> The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm

As this email was sent one week into the revised comment period, and as Spanish-speakers had not yet had the opportunity to read information in Spanish, this shows that there has been an unequal opportunity to comment that is improper.

The Air District's notice was inadequate for all of the affected public. No resident or organization representing residents received notice. We only learned of the original comment period from US EPA after it already had begun.

The Air District published a "Notice" in the Fresno Bee, but not in any Kings County or Spanish-language paper.

Even after meeting with the Air District on August 30, 2010 to raise all these concerns, the Air District refused to hold a public hearing, provide proper notice or provide equal opportunities to the Spanish-speaking residents who comprise a major percentage of residents of Avenal, Kettleman City and Huron.

Due to the discriminatory and disproportionate impact on low-income, Latino and Spanish-speakers of the lack of notice and full public participation notice for a project that would emit pollutants into an already over-polluted area, the Air District has violated its own environmental justice policy as well as California Government Code section 11135 and Title VI of the US Civil Rights Act of 1964.

District's Response:

The District complied with all applicable regulatory public noticing requirements with respect to the Avenal Power Center Preliminary Determination of Compliance (PDOC) and in fact took considerable actions that went far beyond statutory requirements. The District properly published notice of the proposed issuance of the PDOC in a newspaper of general circulation, in this case, the Fresno Bee whose distribution does cover the area in question. This notice was published according to our federally approved Rule 2201, which defines the timing and process of such notices. There is no additional direction on public noticing in the District's Environmental Justice Strategy document, contrary to the commenter's claims.

However, we went far beyond our required notification processes for this project, as follows:

1. *We published this notice, as we do all public notices, on the District's website, valleyair.org. This is not required by any rule or regulation, but is part of our continuing effort to make information available and accessible.*

2. *Upon hearing on August 16 of the commenter's concern that he was not notified of the District proposal to issue a DOC, we promptly, on August 18, notified him that we would extend the public noticing period for him and his clients a full additional 30 days from the date that he heard about our proposal. This was not required, since the commenter had not requested that he be informed of our actions on this project, and therefore he was not on record as an interested party. However, in the interests of providing the maximum reasonable opportunity for comment, we offered this accommodation.*

3. *Upon receiving the commenter's subsequent August 19 request for bilingual information on the project, and a public hearing, on August 20 we sent the commenter the following email, from which he quoted an excerpt above. We are providing it in full, below, as it explains our response in some additional detail that was missing from the commenter's excerpt:*

> *Bradley,*
>
> *The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm*
>
> *We would welcome your assistance in distributing it to your Spanish-speaking clients and associates. We will also be pleased to accept comments in Spanish as we have translation capabilities here at the District. As you are aware, we have already extended the public comment period to September 13, 2010, and we believe the above steps will provide you and your Spanish speaking associates ample opportunity to provide comment on our proposal.*
>
> *I just want to make sure you understand the status of this project atthis time as it pertains to the District. The District is taking public comment on a Preliminary Determination of Compliance, which is a recommendation to the California Energy Commission (CEC) that the project will comply with District regulations. We are not aware of any requirement that we hold a meeting for the purpose of receiving verbal comments.*
>
> *We are not going to hold a public hearing on this project at this time. Ours is not a final permitting decision and there is no hearing process associated with it - the CEC has the sole power plant licensing authority in the state of California for power plants over 50 megawatts. They conduct any necessary public hearings associated with such a license. Our action is a certification to the CEC that, if granted, CEC's license would meet our air quality requirements. CEC is able to accept or reject our proposed conditions of approval, or can make air quality permitting decisions contrary to our determination of compliance. In addition, the CEC makes all determinations regarding power plant siting.*

Finally, contrary to your contention below, the District is not required to hold a public hearing, by rule or by policy We believe the process described above will assure an efficient, fair, and productive public comment process.

Dave Warner
Director of Permit Services
San Joaquin Valley APCD

In summary, we confirmed that we would prepare a Spanish-language summary of the project and make it available to the commenter for his outreach efforts. We also confirmed our commitment to address any comments we received in Spanish, and we explained the limitations of our role in the permitting process to provide clarity to any potential commenters. None of this was required by our rules and regulations, but was intended to provide additional opportunity for community members to participate in the process.

4. *We then worked through the weekend to create a summary of the project, translate it to Spanish, and post it on the website the very next working day, Monday, August 23.*

5. *Next, on August 24 we agreed to meet with the commenter and any of his clients and community members on August 30. The commenter and other activist organization representatives attended the meeting, but, disappointingly, no independent community members. Again, this meeting was not required by any rule or regulation.*

6. *Finally, we granted another request from another employee of GreenAction that she be provided with an additional day to persuade community members of Avenal and Kettleman City to submit comments, extending the comment period to September 14, for a total public comment period of 53 days instead of the required 30 days. This provided GreenAction the opportunity to persuade community members to submit the comments summarized in the next comment section. And again, there was certainly no rule or regulation that required this accommodation.*

In summary, contrary to the assertions of the commenter, the District not only met all legal requirements but went far beyond them in providing the public opportunities to comment on the Avenal Power Center Project.

Greenaction Comment #2:

The claim by the company and the Air District that there would be substantially less emissions than were stated in the initial permit application dramatically conflicts with earlier information and needs extensive scrutiny including a full public environmental review. If there really would be dramatically lower emissions than first claimed, we wonder why the company did not state this initially, raising questions as to whether the lower, newer estimate is based solely on a desire to avoid a PSD permit requirement and protracted appeals and legal battles.

District's Response:

While no response is necessary, it should be noted that the proposal for lower annual emissions was only possible after rigorous analysis by Avenal Power of actual emissions data from other recently constructed similar power plants. In addition, it seems remarkable that there should be a complaint about a company committing to lower emissions from a facility, regardless of the purpose or intent of the proposal.

Greenaction Comment #3:

The Air District's claim that there would be "zero impact" from the proposed power plant's emissions flies in the face of reality. A huge fossil fuel power plant, no matter how much cleaner than others of its kind, still will have pollution impacts. This "zero impact" claim ignores the fact that this would be a fossil fuel power plant that would have emissions and use fuels that contribute to climate change, would emit a broad range of pollutants, and its emissions would act cumulatively in concert with the many other pollution sources in the area.

The proposed fossil fuel power plant would be close to Kettleman City, a small low-income community of color that is suffering a horrible health crisis involving a large number of birth defects and infant deaths. Even a minor increase in emissions near this community could have severe and unforeseen health impacts due to the current health vulnerability of residents. In addition, the entire San Joaquin Valley already suffers from high rates of asthma, and if built this power plant would emit asthma-triggering pollutants.

District's Response:

The District has searched the PDOC and has not been able to locate the phrase "zero impact".

However, the District has performed a Health Risk Assessment (HRA) as well as an Ambient Air Quality Analysis (AAQA) for this facility. The HRA was performed using the AERMOD model and Hot Spots Analysis and Reporting Program (HARP), and demonstrated that the acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Pursuant to the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit with a cancer risk less than one in one million, and chronic or acute hazard index less than 1.

The AAQA demonstrated that the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X. In addition, as shown in the PDOC, the calculated contribution of PM_{10} will not exceed the EPA significance level. Therefore, this project will not cause or contribute significantly to a violation of the State or National AAQS.

Greenaction Comment #4:

This proposed fossil fuel power plant is not needed. Many things have changed since the CPUC originally determined that the Avenal Power Center was needed. As California emerges from an economic recession, the energy landscape has changed. PG&E now has access to more electricity generation than it needs. Last summer, PG&E's territory operated with a 44% reserve margin during summer peak. This extraordinarily high margin is in part due to the CPUC's success at increasing energy efficiency and the demand decrease from the recession. These factors, along with delayed facility retirements and inflated population and energy export assumptions made by the CEC demonstrate that the 600 MWs that the Avenal Power Center would generate are no longer needed. Even PG&E has forecasted a decrease in need. In addition, several large solar projects are to be sited here, and other solar projects are already underway, providing truly clean and renewable energy instead of dirty fossil fuel energy.

Despite all this evidence, Avenal Power Center continues its push for this power plant. The pollution and health effects of this proposed facility are unacceptable when the new capacity is clearly not needed. Finally, allowing unneeded fossil fuel energy would also likely crowd out renewable projects.

District's Response:

The District is not able to take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission.

ATTACHMENT L

NRDC and CRPE Comments and District Responses

National Resources Defense Council (NRDC) and Center on Race, Poverty & The Environment (CRPE) Comments / District Response

The comments (from Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

NRDC and CRPE Comments – Letter Dated September 13, 2010

NRDC and CRPE Comment #1:

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year* –$1,600 per person – in the San Joaquin Valley.

District's Response:

The District has demonstrated in the PDOC that the proposed facility is in compliance with all applicable NO_X and VOC rules and regulations. It should be noted that these rules and regulations are among the strictest and most stringent in the nation and are designed to protect the health of the residents of the San Joaquin Valley.

NRDC and CRPE Comment #2:

The June, 2009 EPA Statement of Basis And Ambient Air Quality Impact Report for a prevention of significant deterioration (PSD) permit states, at page 14, that emissions of CO and NOx from the Project are expected to be 1,205,400 pounds per year and 288,600 pounds per year, respectively. The July 13, 2010 Revised Preliminary Determination of Compliance for the Project states, at page 1, that emissions of CO will now be 197,928 pounds per year and NOx 198,840 pounds per year, both to be enforced as permit limitations. Conveniently, this would bring both the CO and NOx emissions under the 100-ton limit for major sources under Title V of the Clean Air Act. This change in emission numbers was accomplished with no changes to the setup or operation of the Project itself.

In addition, this sentence occurs relating to the new CO and NOx limits:

> If the annual [CO/NOx] emissions from these units exceed this value, they will be set equal to the proposed facility wide [CO/NOx] emission limit.

Revised PDOC at pages 9 (NOx) and 10 (CO). There are two ways to read this confusing sentence. One is that the sub-100 tons limits are meaningless and will be ignored if exceeded. The other is that APCD is attempting to engage in the type of "flexible permitting" that USEPA has disapproved in Texas. In either case, the federal Clean Air Act has been violated.

District's Response:

The District agrees that the wording in the PDOC is slightly confusing. The intent of the statement was to explain that the potential annual emissions from each of the turbines was calculated based on a stated scenario that was provided by the applicant and that if the unit was not operated exactly in accordance with this scenario, there was the potential for higher NO_X and CO emissions from the unit. However, the total emissions from the facility would not be allowed to exceed the proposed facility wide NO_X and CO emissions limits.

The stated scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, the facility cannot be held to a specific operational schedule. The main point to understand is that the annual emissions from the facility will not exceed the facility wide limit that is stated as a condition on the PDOC, and therefore the impact from the facility's emissions will not be greater than that evaluated by the District.

Attached Letter Addressed to U.S. EPA - Dated October 14, 2009

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comments

The following comments were sent to U.S. EPA on October 14, 2009 from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit on behalf of El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, the Center on Race, Poverty, & the Environment, and the Natural Resources Defense Council. These comments were not sent to the District therefore, the District did not previously respond to the comments. These comments refer to the DOC performed in District project C-1080386, which analyzed the prior, higher-emitting proposal. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments (from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #1:</u>

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year*–$1,600 per person – in the San Joaquin Valley.

<u>District's Response:</u>

This is the same comment that was made in the NRDC and CRPE Letter Dated September 13, 2010 and addressed above. See above for District Response.

<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #2:</u>

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

<u>District's Response:</u>

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #3:

The Project is expected to emit 80.7 tons/year of PM/PM10. *See* the June 16, 2009 EPA Statement of Basis and Ambient Air Quality Impact Report at p. 14. As we discuss below, we believe that the Project's plan to offset these PM emissions through SOx offsets is invalid under the Clean Air Act. Accordingly, ambient air quality will be impaired by the Project.

As you know, the San Joaquin Valley is in non-attainment for PM2.5. The Project proposes to meet 98% of its PM offset requirements from SOx offsets at a one-to-one ratio. *See* Final Staff Report, Air Quality Table 19. This is highly problematic for a number of reasons.

First, the one-to-one ratio ignores the very different health risks of SOx and PM. The U.S. EPA has found that particulate matter can cause or contribute to increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing, for example; decreased lung function; aggravated asthma; development of chronic bronchitis; irregular heartbeat; nonfatal heart attacks; and premature death in people with heart or lung disease.

Second, the Project applicants should not be allowed to use PM10 as a surrogate for PM2.5 emissions.

District's Response:

The facility is not using PM_{10} as a surrogate for $PM_{2.5}$. The facility has proposed to offset PM_{10} emissions with SO_X ERCs at the District evaluated interpollutant offset ratios. District Rule 2201, Section 4.13.3 allows for the use of interpollutant offsets at ratios based on air quality analysis. The SO_X for PM_{10} offset ratio used in this project is based on the best available science for determining how much PM_{10} SO_X can create. In addition, the facility is not a Major Source for $PM_{2.5}$ emissions; therefore $PM_{2.5}$ requirements will not be addressed in this project.

Attached Letter Addressed to U.S. EPA - Dated October 15, 2009

EarthJustice Comments

The following comments were sent to U.S. EPA on October 15, 2009 from Paul Cort of EarthJustice. These comments were not sent to the District therefore, the District did not respond to the comments. These comments refer to the DOC performed in District project C-1080386. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments from Paul Cort regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's response.

EarthJustice Comment #1:

Commenter's find it stunning that the proposed permit does not even mention CO2 emissions or controls. EPA is well aware that the Environmental Appeals Board ("EAB") has returned multiple PSD permits for failing to consider whether CO2 is a pollutant "subject to regulation" under the Clean Air Act. *See In re Deseret Power Elec. Coop.*, PSD Appeal No. 07 - 03 (EAB Nov. 13, 2008); *In re Northern Mich. University Ripley Heating Plant*, PSD Appeal No. 08 - 02 (EAB Feb. 18, 2009). In light of these decisions, EPA Region 9 also withdrew portions of the PSD Permit issued to Desert Rock Energy Company in order to reconsider the issue of whether CO2 is a pollutant subject to regulation. Yet EPA proposes a PSD permit for another power plant that will emit over 1.7 million tons of CO2 each year without any discussion of these contentious issues whatsoever. EPA must revise the proposed permit to explain EPA's position on BACT for CO2 so that the public can comment on the control levels selected or EPA's rationale for refusing to impose such controls.

District's Response:

This is the same comment that was made in the NRDC and CRPE Letter dated September 13, 2010 and addressed above. See above for District Response.

EarthJustice Comment #2:

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

District's Response:

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

EarthJustice Comment #3:

The Proposed Permit Fails to Demonstrate that the Avenal Project Will Not Cause or Contribute to Violations of National Ambient Air Quality Standards for Ozone and Fine Particulate Matter.

District's Response:

The facility is not a Major Source for $PM_{2.5}$; therefore $PM_{2.5}$ (fine particulate matter) requirements will not be addressed in this project.

There is no EPA approved model capable of accounting for the photochemical complexities of regional ozone formation to determine the impacts of ozone from a single site due to NOx and VOC emissions. In addition, the facility in this project does not directly emit ozone. Therefore, an analysis of nearby ozone emissions impacts was not performed in this project. Finally, we believe that our very strict standards for NOx and VOC from new sources, among the most stringent in the nation, are sufficient safeguard to prevent any single source from contributing significantly to a violation of the ozone NAAQS.

ATTACHMENT M

Rob Simpson Comments and District Responses

Public Comments / District Response

The comments (from Rob Simpson) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Rob Simpson Comments – Emailed Letters Received November 17, 2010

Simpson Comment #1 - Public Notice:

The notice was not given to me in sufficient enough time to prepare adequate comments. The newspaper notice does not provide enough information about the project to the public and was not published in Spanish.

District's Response:

On the contrary, although Mr. Simpson was not on record as being interested in receiving information regarding this specific project, we are always quite interested in providing interested parties an opportunity to provide input, and so we provided a full 30-day period for Mr. Simpson to comment, the same amount of time provided all interested parties on all permitting projects. As for the second comment, please refer to our response to GreenAction's comment #1.

Simpson Comment #2:

The revised PDOC seems to have one purpose, evasion of the Clean Air Act requirements for the Prevention of Significant Deterioration (PSD). The only change in the revised permit is a limitation on annual NOx and CO emissions but the way the permit is worded this limitation is not federally enforceable. Page 9 of the PDOC states that,

> "*The facility has proposed to limit the annual facility wide NOx emissions to 198,840 lb/year. If the annual NOx emissions from these units exceed this value, they will be set equal to the proposed facility wide NOx emission limit.*"

Page 10 of the PDOC states:

> *"The facility has proposed to limit the annual facility wide CO emissions to 197,928 lb/year. If the annual CO emissions from 'these units exceed this value, they will be set equal to the proposed facility wide CO emission limit."*

So essentially there is no change from the original permit and the Avenal Power Project still requires a PSD permit. Issuance of this permit would be a violation of the Clean Air Act and the district and the applicant would be subject to enforcement.

District's Response:

See response to NRDC and CRPE comment #2.

Simpson Comment #3 - The District is the Lead Agency for this Project:

The CEC appears to no longer be the lead agency for the project the district under CEQA, CEC or District rules. The District is now the lead agency since the purpose of the revision to the permit is merely to avoid PSD review and the CEC has no jurisdiction over PSD issues on this project. Thus the district is now the lead agency for review of this project and must conduct a complete EIR prior to issuance of an Authority to Construct for this project.

District's Response:

The District is not the lead agency for this project. Pursuant to California Public Resources Code Section 25500, the CEC "shall have the exclusive power to certify all sites (for power plants over 50 MW) and related facilities in the state". The California Public Resources Code further states that "the issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency".

Simpson Comment #4 - Is an FDOC an ATC?:

- Does the FDOC process comport with the Districts Federal permitting requirements?
- Is it the federal New Source Review (NSR) permit?
- Has the prior FDOC expired for this facility?
- Has the Applicant commenced construction or use of the prior FDOC?

District's Response:

The FDOC complies with Federal non-attainment pollutant permitting requirements, as implemented with the District's EPA-approved non-attainment NSR rule. This rule requires the District to issue a Determination of Compliance, rather than an Authority to Construct because, as noted above, the CEC has the sole licensing authority for large power plants in California. Our NSR rule does not incorporate federal attainment NSR (PSD) requirements. EPA retains the sole authority to issue PSD permits in the San Joaquin Valley.. The prior FDOC is tied to the CEC's license that has been issued, therefore it has not expired. However, the facility has not commenced construction or use of the prior FDOC. The FDOC under which construction is commenced (and only after CEC has approved any related licensing action) will determine the conditions under which the facility must operate.

Simpson Comment #5:

- I contend that the Warren Alquist Act hijacks air districts authority under the Clean Air Act in conflict with Federal law, does the District agree?.
- Does the District agree with the Brief submitted by the South Coast Air District (Exhibit 3) in the Humboldt Superior Court proceeding regarding a power plant permit that I appealed?

District's Response:

The District does not agree with either the "hijack" comment or the South Coast AQMD's brief on the subject. State law provides the CEC with sole permitting authority, but does not allow them to issue a license that violates the District's regulations. The DOC process provides the District ample opportunity to provide the appropriate guidance to the CEC prior to their licensing process. This process does not violate federal permitting requirements in any way. The federal EPA has approved the DOC process as embodied in the language of the District's NSR rule and that approval explicitly acknowledges that the process complies with federal permitting requirements.

Simpson Comment #6:

The District indicated in emails that it did not intend to issue an Authority to Construct for this project. Please provide some indication of how the permit would be enforceable without an Authority to Construct and who could enforce the State and Federal aspects of the permit. The PDOC has extensive references to an ATC.

District's Response:

Thank you for pointing out that we referred to the DOC as the ATC several times in our evaluation. We apologize for that error. The District has removed all references to the issuance of ATC's in the FDOC evaluation.

Pursuant to District Rule 2201, Section 5.8.9, the APCO shall issue a Permit to Operate to any applicant receiving a certificate from the California Energy Commission pursuant to this rule provided that the construction or modification is in compliance with all conditions of the certificate and of the Determination of Compliance, and provided that the Permit to Operate includes the conditions prescribed in Section 5.7. The District will then perform inspections of the facility to determine if it meets all requirements on their PTO.

Simpson Comment #7 - The BACT Analysis for the Permit is Defective:

The district's top down BACT analysis for NOx is defective because it fails to:

- Identify any alternative technologies or work practices which are technologically feasible for reducing NOx emissions, and
- To quantify the collateral impacts from the selection of SCR as the proposed alternative, and
- Identify combustion technologies that are effective is reducing NO_X emissions. (i.e. steam injection, dry low NO_X combustors, and catalytic combustors), and
- Analyze post-combustion controls including selective noncatalytic combustion and EM, and
- Evaluate the risk of an accident from the transport of NH_3, and
- Evaluate NH_3 as a precursor to PM2.5.

District's Response:

The District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The existing Top-Down BACT Analysis did not consider any NO_X *emissions control other than the use of SCR to lower the* NO_X *emissions to 2.0 ppmvd @ 15%* O_2*, as no more efficient technology has been identified. Pursuant to the District BACT Policy, no analysis is necessary for a project in which the most effective control alternative listed in the BACT Guideline is selected. BACT Guideline 3.4.2 identifies BACT for* NO_X *as the use of SCR or equal to meet an emission concentration limit of 2.0 ppmvd @ 15%* O_2 *as the most stringent technologically feasible* NO_X *requirement. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.*

In addition, BACT only covers operational emissions; therefore the risk from accidents during the transport of NH_3 *is not evaluated and can not be evaluated under the District's NSR rule.*

The evaluation of NH_3 *as a precursor to* $PM_{2.5}$ *was not performed since the facility is not a Major Source for* $PM_{2.5}$ *emissions. However, it should be noted that the Valley's atmosphere does contain ammonia, largely from the Valley's considerable agricultural operations, and relatively small amounts caused by SCR systems are insignificant and are quite worth the significant NOx emissions reductions generated by the SCR. In addition, the District did analyze the health risk impacts of the NH3 emissions that are resulting from the requirement that SCR be installed, and there is no significant risk. Also see the response to comment #17, below.*

Simpson Comment #8 - NO_X Emissions During Startup and Shut Down:

Emissions are greater during startups, shutdowns and combustor tuning periods than they are during steady-state operation, the BACT limits established for steady-state operations are not technically feasible during these periods. As these limits are not "achievable" during these operating modes, they are not "Best Available Control Technology" as defined in the Federal Regulations. Therefore, alternate BACT limits must be specified for these modes of operation. The discussion of Best Available Control Technologies does not include information on minimizing startup emissions or startup durations. The U.S. Environmental Protection Agency (U.S. EPA) requires that BACT apply not only during normal steady-state operations but also during transient operating periods such as startups. The District should consider conducting, as part of the BACT analysis, a review of combustion turbine and combined cycle system operational controls or design features that can shorten start up and shutdown events and optimize emission control systems.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised.

Simpson Comment #9 - BACT VOC Emission Limit:

The district has selected a VOC emission limit of 1.4 ppmvd @ 15% 02 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% 02 when it is fired with the duct burners. The BAAQMD has recently established a BACT VOC emission limit for large gas turbines for VOC's. BACT is the use of good combustion practice and abatement with an oxidation catalyst to achieve a permit limit for each gas turbine of 0.616 lb per hour or 0.00127 lb/MMBtu, which is equivalent to 1 ppm POC, 1-hr average. Since VOC emissions contribute to ozone formation and the district is in severe non attainment for the 8-hour ozone standard the district should adhere to the lower VOC emission rate or provide a top down BACT evaluation which shows that this rate is not achievable or is not cost effective.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The District Top-Down BACT Analysis did not consider any VOC emissions control other than limiting the VOC emissions to 2.0 ppmvd @ 15% O_2 when the duct burner is fired, and 1.5 ppmvd @ 15% O_2 when the duct burner is not fired.

The applicant proposed VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct *burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet the highest ranking control option listed in the BACT. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.*

<u>Simpson Comment #10 - BACT $PM_{2.5}$ / PM_{10} Emission Limit:</u>

The permit proposes to allow the project to emit as much as 11.78 pounds per hour of PM-10 with the project utilizing duct firing. According to BAAQMD the projects listed in the table below all have lower PM emission limits than those proposed for this project. BACT for PM 2.5 for large combined cycle turbines with duct firing is 9 pounds per hour. The district needs to impose this limit in the FDOC.

<u>District's Response:</u>

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. *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 PM_{10} 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. In addition, it is likely that a PM10 limit of 11.78 lb/hr is substantially the same as a PM2.5 limit of 9.0 lbs/hr, as PM2.5 is a fraction of PM10.*

<u>Simpson Comment #11 - Air Quality Impact Analysis:</u>

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. For NOx the impact analysis conducted by the district in Attachment G page 2 demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98^{th} percentile of the annual distribution of the daily 1 hour max ppb /ug/m3 for the Visalia site which is 115.72 ug/m3. So the project does in fact violate the new federal NO2 standard and thus cannot be permitted.

<u>District's Response:</u>

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour *max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.*

Simpson Comment #12:

The PDOC uses the PM-10 surrogate approach to analyze the particulate matter impacts from the project. On October 20, 2010, the USEPA issued a final rule providing modeling thresholds for evaluating impacts of PM2.5 emissions under the Prevention of Significant Deterioration (PSD) program and the Non attainment NSR program. The rule establishes Class I and Class II Increment Thresholds and Significant Impact Levels (SILs), and a Significant Monitoring Concentration (SMC) threshold. The project according to the analysis presented on page 54 exceeds both the significant impact levels for the annual PM 2.5 standard and the 24 PM 2.5 hour standard. The FDOC needs to address the compliance of the project with the new rules.

District's Response:

The project does not trigger PSD permitting and the facility is not a Major Source for $PM_{2.5}$ emissions. Therefore, the District is not required to perform modeling to evaluate impacts of $PM_{2.5}$.

Simpson Comment #13 - Federal 1 hour NO2 Standard:

The permit does not present an adequate and complete analysis for the new Federal 1 hour NO2 standard. The district failed to include information on any nearby sources which are required to be modeled with Avenal's emissions. A full impact analysis should be presented in the permit for the public to comment on using the EPA's Guideline on Air Quality Models (40 CFR Part 51 Appendix W).

District's Response:

This project does not trigger a PSD permit and therefore it is not required to follow the guideline on air quality models in 40 CFR Part 51 Appendix W. If it did trigger PSD permitting, the federal EPA would be obligated to perform such modeling, if appropriate.

Simpson Comment #14:

The revised permit should provide the input data that was used to determine compliance with the new NO2 standard. Emission factors and NO2 inventories should be presented for the public to review not just the information that is presented on page 2 Attachment G. The analysis on page 2 Attachment G demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98^{th} percentile of the annual distribution of the daily 1 hour max ppb / ug/m3 for the Visalia site which is 115.72 ug/m3.

<u>District's Response:</u>

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.

<u>Simpson Comment #15:</u>

Modeling for the NO2 standard should indicate whether worst case emissions which would be the start up and shut down emissions for the project were utilized in the modeling for compliance with the standard.

<u>District's Response:</u>

The District performed modeling during the commissioning period and the standard operational period to determine compliance with the NO2 standard. The modeling performed by the District for these periods demonstrated compliance with the NO2 standards.

<u>Simpson Comment #16 - The Proposed Interpollutant Trade Values Violates EPA Guidance and $PM_{2.5}$ NSR Regulations:</u>

Based on an EPA assessment, the preferred trading ratios for SO2 to PM2.5 was set at 40:1.

<u>District's Response:</u>

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

<u>Simpson Comment #17 - Ammonia Emissions:</u>

Other power plant turbines have achieved a 2 ppm NO_X limit with a 5 ppm NH_3 slip limit.

The district must consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The district is not an isolated island.

District's 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 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 PM_{10} 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 NOx 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.

Simpson Comment #18 - Emission Reduction Credits:

ERC's used on the prior PDOC are unavailable for use on the new PDOC.

District's Response:

The ERC listed in the previous FDOC and the ones listed in the new PDOC will only be used for one of the projects. Once they are withdrawn for either project, they will no longer be available to be withdrawn for the remaining project. In addition, the applicant has provided sufficient ERC's of offset the emissions increase in either one of the projects.

Simpson Comment #19:

The PDOC indicates that the closest population center is the residential district of Avenal approximately 6 miles to the southwest. Are there people residing or working closer than that to the project? Could there be sensitive receptors closer to the site?

District's Response:

According to the application submitted by the facility, the nearest resident is 7,700 feet to the Northeast and the nearest business is 3,957 feet to the Northwest. However, our analysis of emissions and risk from those emissions is based on a theoretical long-term exposure at the point of maximum pollutant concentration. Therefore, our conclusion that there will be no significant risk from any emissions from this facility is not dependant on receptor location.

Simpson Comment #20:

It appears that there are residential structures and extensive farm land around the site. Could emissions from the facility affect crops or wildlife?

District's Response:

Such issues are addressed in the CEC's CEQA-equivalent process and are not a part of the District's analysis. However, it should be noted that the District's Health Risk Assessment (HRA) is a multipathway assessment of risk, and would include the affect on public health generated by pollutant deposition on plants and animals that are subsequently ingested by the public.

Simpson Comment #21:

- Has the District conducted and Environmental Justice analysis of the projects effects? Could farm workers be an environmental justice community that suffers a greater impact due to hard physical labor in the vicinity of the project, lack of health care, poverty and additional stressors like chemicals used in farming?
- Can farming activities cause additional air quality impacts that could contribute to a negative cumulative effect?
- Will this facility induce growth?
- Could on site Solar pre-heaters reduce Air quality impacts?
- Can this facility cause an increase of greenhouse gas emissions?
- Are there potential negative localized effects of Greenhouse gases?
- How does this plan comport with AB32?
- How does this plan comport with EXECUTIVE ORDER S-3-05?
- Has the District studied the potential air quality effects of the use of imported LNG?
- The District should study the life cycle effects of fossil fuel extraction and delivery?
- Has the District studied the effects of the facility utilizing water from the California Aqueduct?
- Will the vaporization of this water lead to negative air quality effects by increasing PM or other pollutants in the Air?

- Will the use of this water cause negative air quality effects by the diversion of water that could be utilized for farming or other uses?
- Will the pumping of this water through the Aqueduct, from its source, cause Air quality emissions?
- Is it legal to use Potable water for this Power plant use?
- As water quality changes will these effects change?
- Are there methods of minimizing these potential effects? Dry cooling for instance?

District's Response:

These questions should be directed to the CEQA lead agency for this project (CEC). Since the District is not the lead agency for this project, these comments will not be addressed at this time.

Simpson Comment #22:

How much money does the District receive if this project is approved? Denied?

District's Response:

Whether the project is approved or denied, the District receives application filing fees for all proposed equipment, and hourly engineering fees for the time spent evaluating the project. At this time, we would expect the total will be approximately $5,000. In addition, if the project is approved, the District will receive an annual permit fee to maintain the facility's permits, of approximately $26,000 per year. This latter amount would be the same whether the facility constructs under the conditions of this FDOC and a subsequent CEC approval, or under the existing FDOC which the CEC used in issuing the existing power plant license.

Comments Received from Rob Simpson in Exhibit 4:

The document provided labeled Exhibit 4 is the same document that Mr. Simpson presented as testimony for the CEC Hearings under proceeding 08-AFC-01. This exhibit was discussed at the Pre-Hearing Conference on June 30, 2009. After a review of the document, the CEC Committee overseeing the project concluded that the only information that would be allowed as testimony would be the information included in Exhibit W. A discussion of this can be found in the Pre-Hearing Conference Transcript, available at: http://www.energy.ca.gov/sitingcases/avenal/documents/2009-06-30_TRANSCRIPT.PDF. The District agrees with CEC's conclusion and will respond to the comments presented in Exhibit W. All additional comments in Exhibit 4 are documents pertaining to projects unrelated to this project, and comments that are not applicable to this project.

Simpson Comment #23:

The applicant proposes to offset the projects PM 2.5 emissions on a pound for pound basis with SOx offsets. Proposed interpollutant trading ratios are required to be scientifically justified with a site specific air quality analysis, as required by Rule 2201, Section 4.13.3. The PDOC attempts to establish an interpollutant ratio based on modeling analyses performed in the Districts 2008 PM 2.5 plan.

The EPA has finalized its regulations to implement the New Source Review (NSR) program for fine particulate matter on July 15, 2008. Their recommended ratio of SOx offsets to PM 2.5 offsets is 40 tons of SOx for each ton of PM 2.5. The applicant is proposing a ratio that is 40 times less stringent than EPA has recommended.

In addition the CEC and the air district allow the project to emit 33,521 pounds of SO2 with no mitigation despite the alleged CEC policy to offset all PM2.5 precursors. If one pound of SO2 offsets 1 pound of PM 2.5 the CEC and the Air District are allowing 33,521 pounds of SO2 to remain unmitigated. The new EPA rules on PM 2.5 require a pound for pound offset ratio for PM 2.5 precursors. If the districts assumption that one pound of SOx offsets 1 pound of PM 2.5 as allowed in the interpollutant trade the district is allowing 33,521 pounds of SOx to remain unmitigated creating 33,521 pounds of PM 2.5 in violation of CEQA and EPA NSAR rules for PM 2.5.

District's Response:

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

Simpson Comment #24:

The FDOC allows an ammonia slip of 10 ppm. The 5 ppm ammonia limit in combination with a 2 ppm NO limit has already been required for some CEC licensed facilities. In the alternative the District could perform a site specific analysis that demonstrates that no particulate matter will be formed locally or district wide due to the ammonia slip emissions and require mitigation if the analysis demonstrates that there is significant secondary particulate matter formation from the ammonia emissions from the LGS.

The district must also consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident.

District's Response:

This comment was addressed in the District response to Rob Simpson Comment #17 above.

Comments Received from Rob Simpson in Exhibit 5:

The document labeled Exhibit 5, submitted by Rob Simpson, discusses the California energy landscape. The District does not take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission (CEC).