San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DOCKET	
08-AFC-7	
DATE	8/18/2009
RECD.	8/24/2009

AUG 1 8 2009

Alan Solomon
Project Manager
Siting, Transmission and Environmental Protection Division
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

Re: Notice of Final Determination of Compliance (FDOC)
Facility: GWF Energy, LLC – Tracy (08-AFC-07)
Project Number: N-1083212

Dear Mr. Solomon:

Enclosed is the District's Final Determination of Compliance (FDOC) for the modification of two 84.4 MW simple-cycle peak-demand power generating gas turbine systems to convert the power plant into a combined-cycle power plant with the installation of two new heat recovery steam generators on each turbine's exhaust and one new 145 MW steam turbine (shared between both turbines), the installation of one 85 MMBtu/hr natural gas fired auxiliary boiler, the installation of one 288 bhp diesel fired emergency internal combustion engine powering a firewater pump, and the modification of an existing 471 bhp engine powering an emergency generator to reduce the non-emergency hour limit to 50 hours for compliance with the ATCM for Stationary Compression Ignition Engines, all located at 14590 W. Schulte Rd in Tracy, CA. This letter serves as our notification of final action and enclosed is your copy of the FDOC.

Notice of the District's preliminary decision was published on April 7, 2009. 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 T, U, and V of the enclosed FDOC package.

The changes made to the PDOC were in direct response to comments received from the oversight agencies, the applicant, 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 significantly 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.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. James Harader of Permit Services at (209) 557-6445.

Sincerely,

David Warner
Director of Permit Services

DW:jh

Enclosures

cc: Brewster Birdsall, Aspen Environmental Group

Stockton Record

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 GWF Energy LLC - Tracy for the modification of two 84.4 MW simple-cycle peak-demand power generating gas turbine systems to convert the power plant into a combined-cycle power plant with the installation of two new heat recovery steam generators on each turbine's exhaust and one new 145 MW steam turbine (shared between both turbines), the installation of one 85 MMBtu/hr natural gas fired auxiliary boiler, the installation of one 288 bhp diesel fired emergency internal combustion engine powering a firewater pump, and the modification of an existing 471 bhp engine powering an emergency generator to reduce the non-emergency hour limit to 50 hours for compliance with the ATCM for Stationary Compression Ignition Engines, all located at 14590 W. Schulte Rd in Tracy, CA

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

The application review for project **N-1083212** is available for public inspection at the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 4800 ENTERPRISE WAY, MODESTO, CA 95356.**

FINAL DETERMINATION OF COMPLIANCE EVALUATION

GWF Tracy Combined-Cycle Power Plant
California Energy Commission
Application for Certification Docket #: 08-AFC-07

Facility Name:	GWF Energy, LLC
Mailing Address:	4300 Railroad Avenue Pittsburg, CA 94565-6006
Contact Name:	Mark Kehoe, Director, Environmental and Safety Projects
Telephone:	(925) 431-1440
Fax:	(925) 431-0518
Engineer:	James Harader, Air Quality Engineer
Lead Engineer:	Sheraz Gill, Supervising Air Quality Engineer
Date:	March 3, 2009
Project #:	N-1083212
Application #'s:	N-4597-1-5, '-2-5, '-4-2 '-5-0, and '-6-0
Submitted:	July 21, 2008
Deemed Complete:	August 22, 2008

Table of Contents

Section		Page
I.	Proposal	1
II.	Applicable Rules	2
III.	Project Location	3
IV.	Process Description	3
V.	Equipment Listing	6
VI.	Emission Control Technology Evaluation	8
VII.	General Calculations	13
VIII.	Compliance	33
IX.	Recommendation	125

ATTACHMENT A	-	PDOC Conditions
ATTACHMENT B	-	PTOs N-4597-1-4, '-2-4, and '-4-1
ATTACHMENT C	-	Project Location and Site Plan
ATTACHMENT D	-	CTG Commissioning Period Emissions Data
ATTACHMENT E	-	CTG Steady State Emissions Data
ATTACHMENT F	-	CTG Startup and Shutdown Emissions Data
ATTACHMENT G	-	Daily and Annual Turbine Emissions Spreadsheets
ATTACHMENT H	-	SJVAPCD BACT Guideline 3.4.7
ATTACHMENT I	-	Pre-Project Actual Emissions Data
ATTACHMENT J	-	Quarterly Net Emissions Change
ATTACHMNET K	-	BACT Guideline 3.4.2 and CTG Top-Down BACT Analysis
ATTACHMENT L	-	BACT Guideline 3.1.3 and Emergency Engine Top-Down BACT Analysis
ATTACHMENT M	-	BACT Guideline 1.1.2 and Boiler Top-Down BACT Analysis
ATTACHMENT N	-	BACT Guideline 3.1.4 and Fire Pump Engine Top-Down BACT Analysis
ATTACHMENT O	-	NOx for VOC and NOx for PM10 Interpollutant Offset Analysis
ATTACHMENT P	-	Compliance Certification for GWF Facilities
ATTACHMENT Q	-	Health Risk Assessment and Ambient Air Quality Analysis
ATTACHMENT R	-	Title V Significant Modification Compliance Certification
ATTACHMENT S	-	District Policy SSP 1105 – Emissions Monitoring for Boilers
ATTACHMENT T	-	GWF Comments and District Response
ATTACHMENT U	-	EPA Comments and District Response
ATTACHMENT V	-	CEC Comments and District Response

I. PROPOSAL:

GWF Tracy Combined Cycle Power Plant, LLC, hereinafter referred to as "GWF Tracy", is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the modification of their existing 169 MW "peaking" simple-cycle electrical power plant to convert the plant into a full-time combined-cycle electrical power plant, increasing the total capacity to approximately 314 MW. The conversion of the existing peaking power plant into a combined-cycle power generation plant will require the following modifications:

- The demolition and removal of the two existing oxidation catalysts and selective catalytic reduction systems serving the existing General Electric (GE) Frame 7EA combustion turbine generators (CTG's), including demolition of the existing 100 foot exhaust stacks, and

- The addition of two new heat recovery steam generators (HRSG), each receiving the exhaust from one of the existing GE Frame 7EA combustion turbine generators, and each equipped with a 324 MMBtu/hr, HHV capacity, natural gas-fired duct burner, and

- The addition of a new and more efficient oxidation catalyst system within each HRSG to control carbon monoxide (CO) and volatile organic compound (VOC) emissions, and

- The addition of a new and more efficient SCR system within each HRSG reusing the existing aqueous ammonia storage system to control oxides of nitrogen (NOx) emissions, and

- The addition of two new 150' tall, 17' diameter exhaust stacks, each equipped with the existing continuous emissions monitoring systems for CO, NOx, and O_2, and

- The addition of a new 85 MMBtu/hr natural gas-fired auxiliary boiler (N-4597-5-0) equipped with ultra low-NOx burners, and

- The addition of a new nominal 145 MW (net output) condensing steam turbine generator (STG), and

- The addition of a new STG lube oil cooler, and

- The addition of a new 114' tall 234' long, 215' wide Air Cooled Condenser (ACC) for system heat rejection, and

- The addition of a new nominal 288 horsepower, diesel-fired engine powering an emergency firewater pump (N-4597-6-0), and

- The modification of the existing 471 horsepower, diesel-fired engine powering a 300 KW electrical generator (N-4597-4-1) to decrease the annual hours of operation from 200 hours/year to 50 hours/year for compliance with the ATCM for Stationary Compression Ignition Engines.

GWF Tracy 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).

GWF Tracy received their Title V Permit on August 24, 2004 for this facility. This modification can be classified as a Title V significant modification pursuant to Rule 2520, Section 3.20, and can be processed with a Certificate of Conformity (COC). Since the facility has specifically requested that this project be processed in that manner, the 45-day EPA comment period and 30-day public notice will be satisfied prior to the issuance of the Authority to Construct. GWF Tracy must apply to administratively amend their Title V Operating Permit to include the requirements of the DOC's issued with this project.

A copy of existing permits N-4597-1-4, '-2-4, and '-4-1 is included in Attachment B.

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 2020	Exemptions (12/20/07)
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)
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/18/00)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4202	Particulate Matter Emission Rate (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4304	Equipment Tuning Procedures for Boilers, Steam Generators, and Process Heaters (12/19/95)
Rule 4305	Boilers, Steam Generators and Process Heaters – Phase II (8/21/03)
Rule 4306	Boilers, Steam Generators and Process Heaters – Phase III (3/17/05)
Rule 4320	Advance Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr (10/16/08)
Rule 4351	Boilers, Steam Generators, and Process Heaters – Phase I (8/21/03)
Rule 4701	Stationary Internal Combustion Engines – Phase 1 (8/21/03)

Rule 4702 Stationary Internal Combustion Engines – Phase 2 (1/18/07)
Rule 4703 Stationary Gas Turbines (8/17/06)
Rule 4801 Sulfur Compounds (12/17/92)
Rule 8011 General Requirements (8/19/04)
Rule 8021 Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031 Bulk Materials (8/19/04)
Rule 8041 Carryout and Trackout (8/19/04)
Rule 8051 Open Areas (8/19/04)
Rule 8061 Paved and Unpaved Roads (8/19/04)
Rule 8071 Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
Rule 8081 Agricultural Sources (9/16/04)
California Environmental Quality Act (CEQA)
California Health & Safety Code (CH&S), Sections 41700 (Health Risk Analysis), 42301.6 (School Notice), and 44300 (Air Toxic "Hot Spots")
Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment
Title 17 CCR, Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines
40 CFR Part 51 Appendix S - Requirements for $PM_{2.5}$

III. PROJECT LOCATION:

The proposed equipment will be located on the SW quarter of Section 36, Township 2 South, and Range 4 East on the United States Geological Survey Quadrangle map. The proposed plant site will occupy approximately 16.38 acres of the existing GWF-owned 40-acre parcel (see site location and layout in Attachment C).

The site is immediately southwest of Tracy, CA and approximately 20 miles southwest of Stockton, CA, both located in San Joaquin County. The District has verified that the proposed location is not within 1,000' of a K-12 school.

IV. PROCESS DESCRIPTION:

<u>Combined-Cycle Combustion Turbine Generators</u>

Each natural gas-fired General Electric Frame 7 Model PG 7121 EA 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 84.4 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and steam turbine both drive electrical generators and produce power.

Each CTG will directly drive an electrical generator, and also produce power by directing exhaust heat through its HRSG, which supplies steam to a 145 MW steam turbine 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, with the duct burner firing
VOC: 1.5 ppmvd @ 15% O_2, without the duct burner firing
CO: 2.0 ppmvd @ 15% O_2

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)

There will be one HRSG per existing CTG. Each HRSG will be a two-pressure configuration and will include the following sections and support systems:

- Low-pressure economizer
- Integral deaerator
- Low-pressure evaporator
- High-pressure economizer
- Low-pressure superheater
- High-pressure superheaters
- A 324 MMBtu/hr (HHV) natural gas-fired duct burner
- SCR and CO, VOC oxidation catalysts
- Ammonia injection grid and vaporizer skid for use with the SCR system
- Boiler feedwater pumps
- High-Pressure Evaporator

Steam Turbine Generator (STG)

Steam generated in the HRSG will be routed to the STG. The steam turbine will extract the thermal energy from the pressurized steam and convert it to mechanical work. The generator, which will be coupled to the steam turbine, will convert the mechanical work into 18-kV electricity. The electric power will be routed through a generator breaker and transformed to 115-kV alternating current (AC) electricity through the generator step up transformer. After travelling through the STG, the steam will exit through the low-pressure turbine exhaust and into the air cooled condenser.

The STG will consist of a high-pressure and low-pressure turbine and is expected to be of a single-case, single-shaft design. It will be coupled to an electrical generator with an approximate rated size of 188 MVA. The STG will be supported by auxiliary systems that include the following:

- Lube oil system – consisting of a tank, heater, and pumps
- Hybrid lube oil cooler – consisting of a parallel wet and dry system
- Hydraulic oil system – consisting of a tank and pumps

- Exciter, automatic voltage regulator, and power system stabilizer
- STG controls system
- Gland condenser
- Generator breaker

Air Cooled Condenser (ACC)

One ACC will be installed with sufficient surface area to reject heat from the steam cycle to the atmosphere. The ACC will be elevated and supported by a steel support structure to ensure adequate air flow. The ACC will consist of the following components and auxiliary systems:

- Approximately 25 modules; each module will contain an A-frame fin and tube heat exchanger
- Two-speed electric fan assembly in each module
- Steam transfer duct from the exhaust outlet of the STG to the ACC
- Steam supply distribution headers and condensate drain headers on the ACC
- Drain piping and storage tank for condensate collection
- Forwarding pumps to convey the condensate back to the HRSG feedwater system
- A dedicated motor control center (MCC)
- An air removal system either by ejectors or liquid ring vacuum pump to maintain adequate ACC vacuum
- Noise mitigation measures to reduce sound levels from fans, pumps, and ejectors

Existing Diesel-Fired Emergency IC Engine Powering an Electrical Generator

Supplementary to the DC battery system, an existing diesel-fueled emergency generator system will provide long-term power for a safe and orderly shutdown of each generating unit following the loss of AC auxiliary power and would provide for long-term essential loads. The emergency generator will be ready to start automatically upon loss of power. The emergency diesel generator skid will store 150 gallons of CARB Certified low sulfur (<0.0015 percent by weight) diesel.

The emergency generator consists of a three-phase, 60-Hz generator driven by a direct coupled engine. The rating of the engine generator is 300 kW. The generator is wye-connected with a solidly grounded neutral.

Auxiliary Boiler

The applicant has proposed the installation of one 85 MMBtu/hr boiler with an Ultra Low NO_X burner. The boiler will provide sparging steam to the HRSG high-pressure drum, to maintain steam turbine seals, and provide ejector steam to the ACC ejector system. The sparging steam supplied to the high-pressure drum will be used to maintain steam drum temperatures to reduce the plant start times and the effects of temperature cycling on the steam drum. The steam provided to the steam turbine will be used to maintain seals. The steam supplied to the ejector system will be used to pull vacuum in the ACC in preparation of receiving steam from the STG or bypass steam from the HRSG.

Diesel-Fired Emergency IC Engine Powering a Fire Pump

The existing fire protection system consists of two electrically driven fire pumps and a jockey pump supplied from an existing 250,000 gallon service/firewater tank. The addition of the STG and the associated lube oil system will require additional fire protection system capacity and redundancy. GWF Tracy is proposing to modify the 250,000 gallon firewater tank to increase its capacity to 300,000 gallons. GWF Tracy will require an additional 400,000 gallon tank (of which 300,000 gallons will be dedicated to fire water) to provide the required redundancy. A new electrical fire water pump and a nominal 288 horsepower, diesel-driven fire pump will serve the plant expansion. The diesel fire pump will provide a second source of fire protection that is not dependent on the electrical system, thereby increasing the reliability of the fire protection system overall.

V. EQUIPMENT LISTING:

Pre-Project Equipment Descriptions:

N-4597-1-4: 84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST

N-4597-2-4: 84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST

N-4597-4-1: 471 HP CATERPILLAR MODEL 3456 DI TA AA DIESEL-FIRED EMERGENCY IC ENGINE POWERING A 300 KW ELECTRICAL GENERATOR

Modification Equipment Descriptions:

N-4597-1-5: MODIFICATION OF AN EXISTING 84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST: TO CONVERT THE EXISTING SYSTEM TO A COMBINED CYCLE CONFIGURATION BY (1) REMOVING THE EXISTING OXIDATION CATALYST AND SELECTIVE CATALYTIC REDUCTION SYSTEM AND THE EXISTING 100 FOOT EXHAUST STACKS, (2) INSTALLING A NEW HEAT RECOVERY STEAM GENERATOR EQUIPPED WITH A 324 MMBTU/HR (HHV) NATURAL GAS-

FIRED DUCT BURNER, (3) INSTALLING A NEW OXIDATION CATALYST AND NEW SELECTIVE CATALYTIC REDUCTION SYSTEM, (4) INSTALLING A NEW 150' TALL 17' DIAMETER STACK, (5) INSTALLING A NEW STG LUBE OIL COOLER, AND (6) INSTALLING A 145 MW NOMINALLY RATED CONDENSING STEAM TURBINE GENERATOR (SHARED WITH N-4597-2)

N-4597-2-6: MODIFICATION OF AN EXISTING 84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST: TO CONVERT THE EXISTING SYSTEM TO A COMBINED CYCLE CONFIGURATION BY (1) REMOVING THE EXISTING OXIDATION CATALYST AND SELECTIVE CATALYTIC REDUCTION SYSTEM AND THE EXISTING 100 FOOT EXHAUST STACKS, (2) INSTALLING A NEW HEAT RECOVERY STEAM GENERATOR EQUIPPED WITH A 324 MMBTU/HR (HHV) NATURAL GAS-FIRED DUCT BURNER, (3) INSTALLING A NEW OXIDATION CATALYST AND NEW SELECTIVE CATALYTIC REDUCTION SYSTEM, (4) INSTALLING A NEW 150' TALL 17' DIAMETER STACK, (5) INSTALLING A NEW STG LUBE OIL COOLER, AND (6) INSTALLING A 145 MW NOMINALLY RATED CONDENSING STEAM TURBINE GENERATOR (SHARED WITH N-4597-1)

N-4597-4-2: MODIFICATION OF A 471 HP CATERPILLAR MODEL 3456 DI TA AA DIESEL-FIRED EMERGENCY IC ENGINE POWERING A 300 KW ELECTRICAL GENERATOR TO REDUCE THE ANNUAL HOURS OF OPERATION FOR MAINTENANCE AND TESTING FROM 200 HOURS/YEAR TO 50 HOURS/YEAR

Post-Project Equipment Descriptions:

N-4597-1-5: 84.4 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NOX COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 324 MMBTU/HR DUCT BURNER AND A 145 MW NOMINALLY RATED STEAM TURBINE (SHARED WITH N-4597-2)

N-4597-2-5: 84.4 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NOX COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 324 MMBTU/HR DUCT

BURNER AND A 145 MW NOMINALLY RATED STEAM TURBINE (SHARED WITH N-4597-1)

N-4597-4-2: 471 HP CATERPILLAR MODEL 3456 DI TA AA TIER 2 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A 300 KW ELECTRICAL GENERATOR

N-4597-5-0: 85 MMBTU/HR NATURAL GAS-FIRED RENTECH MODEL RTD-2-60 BOILER WITH A COEN MODEL C-RMB BURNER AND FLUE GAS RECIRCULATION OR EQUIVALENT

N-4597-6-0: 288 BHP CUMMINS MODEL CFP83-F40 TIER 3 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIREWATER PUMP OR EQUIVALENT

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

NOx, CO, VOC, PM10, and SOx are the primary pollutants created by the combustion of natural gas in the combustion turbine generators. The three primary forms of NOx from combustion turbine generators are thermal NOx, fuel NOx and prompt NOx.

Thermal NOx is formed through the high temperature oxidation of the diatomic nitrogen found in combustion air. The formation of thermal NOx is primarily a function of the temperature and the residence time of the nitrogen at that temperature. At high temperatures, usually above 2900 degrees F, molecular nitrogen (N_2) and oxygen (O_2) in the combustion air disassociate into their atomic states and undergo a series of reactions. The three principal reactions that produce thermal NOx are:

$N_2 + O_2 \rightarrow NO + N$
$N + O_2 \rightarrow NO + O$
$N + OH \rightarrow NO + H$

Thermal NOx increases strongly with fuel to air ratio, firing temperature, and with increasing residence time in the flame zone. Thermal NOx also increases exponentially with combustor inlet air temperature, and increases with the square root of the combustor inlet pressure.

Fuel NOx is created by the conversion of fuel bound nitrogen into NOx. During combustion, nitrogen bound in the fuel is released as a free radical and ultimately forms free N_2 or NO. Fuel NOx can contribute as much as 50% of total emissions when combusting oil and as much as 80% when combusting coal; however, when combusting natural gas the quantity of fuel NOx created is relatively small when compared to the quantity of thermal NOx created.

Prompt NOx is the third primary source of NOx from combustion. Prompt NOx is attributed to the reaction of atmospheric nitrogen, N_2, with radicals such as C, CH, and CH_2 fragments derived from the fuel. Occurring at the earliest stage of combustion, the reactions of N_2 with the radical fragments derived from the fuel results in the formation of fixed species of nitrogen such as nitrogen monohydride (NH), hydrogen cyanide (HCN), di-hydrogen cyanide (H_2CN) and cyano radical (CN^-), each which can oxidize to form NO.

The control of NOx emissions from turbines is achieved through the use of both "front end" NOx control technologies and "back end" NOx technologies. Front end NOx control technologies reduce the quantity of NOx created during the combustion of the fuel. Since fuel NOx is only a minor contributor to the overall NOx emissions when combusting natural gas and prompt NOx is difficult to control, front end control technologies primarily focus on limiting the production of thermal NOx. The GE Frame 7EA turbines currently permitted at this facility utilize staged lean premixed combustion technology, a type of Dry Low NOx (DLN) control system, to reduce thermal NOx emissions. The concept of lean premixed combustion is to have a uniform, lean fuel-air mixture throughout the combustion zone, with no fuel-rich pockets where high flame temperatures would cause NOx formation. Reducing NOx emissions generally results in an increase in other emissions. In the case of lean premixed combustors the low flame temperature necessary to preclude NOx formation also slows down the oxidation of CO to CO_2 and the complete combustion of the hydrocarbon fuel.

Back end NOx control technologies reduce the quantity of NOx in the turbine exhaust via chemical reactions in the presence of a catalyst that convert NOx into molecular nitrogen and water or convert NOx into potassium nitrites and nitrates. The back end NOx control technology proposed by the applicant is the use of a Selective Catalytic Reduction (SCR) system. In the SCR process, ammonia (NH) is injected into the gas turbine exhaust gas stream as it passes through the heat recovery steam generator and reacts with nitrogen oxide molecules in the presence of a catalyst to form molecular nitrogen and water. The NOx-ammonia reaction takes place over a limited temperature range (approximately 600 F to 750 F). Unreacted ammonia (ammonia slip), an air contaminant, is exhausted from the SCR system.

Pursuant to the applicant, the use of Dry-Low NOx combustion technology and an SCR system will reduce NOx emissions from GWF Tracy's combustion turbines below 2 ppmvd @ 15% O_2 (based on 1-hr standard) during normal operation of the turbines. The proposed maximum ammonia slip (NH_3) concentration in the exhaust is 5 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.

The applicant has proposed the use of an oxidation catalyst to reduce carbon monoxide emissions from the combustion gas turbines. The catalyst converts CO into CO_2 via the following reaction:

$2CO + O_2 \rightarrow 2CO_2$

Pursuant to the applicant, the use of an oxidation catalyst will reduce CO emissions below 2 ppmvd @ 15% O_2 (based on a 3-hour average) during normal operation of the turbines.

VOC emissions are the result of incomplete combustion of fuel in the turbine. The proposed oxidation catalyst converts unburned hydrocarbons into CO_2 and H_2O via the following reaction:
$2C_xH_y + (2x + y/2)O_2 \rightarrow 2xCO_2 + yH_2O$

Pursuant to the applicant, the use of an oxidation catalyst will reduce VOC emissions below 2 ppmvd @ 15% O_2 when the duct burner is firing, and below 1.5 ppmvd @ 15% O_2 when the duct burner is not firing.

All sulfur emissions in the gas turbine exhaust are caused by the combustion of sulfur introduced into the turbine by the fuel or air. Since most ambient air has little or no sulfur, the most common source of sulfur is the fuel. To control sulfur emissions, the facility is proposing the use of natural gas fuel with a maximum daily sulfur content of 0.66 grains/100 scf fuel and an annual average sulfur content of 0.25 grains/100 scf fuel.

Gas turbine exhaust particulate emission rates are influenced by the design of the combustion system, fuel properties and combustor operating conditions. The principal components of particulates are smoke, ash, ambient non-combustibles, and erosion and corrosion products. Two additional components are sulfuric acid and unburned hydrocarbons that are liquid at standard conditions. Smoke is the visible portion of particulate matter. For natural gas turbines, visible smoke is typically not present. Additionally, particulate emissions are created by the use of the SCR system and the oxidation catalyst. Unreacted ammonia from the SCR system combines with sulfur trioxide (SO_3) and water to form ammonium salts such as ammonium bisulfate, NH_4HSO_4, and ammonium sulfate $(NH_4)SO_4$. The quantity of SO_3 available for this reaction is significantly increased by the use of supplementary firing in the HRSG (duct burner) and the use of an oxidation catalyst, both which oxidize sulfur and sulfur dioxide into SO_3.

Reductions in particulate matter are achieved by limiting the quantity of sulfur in the fuel and the ammonia slip. The applicant has proposed the use of natural gas fuel with a maximum sulfur content of 0.66 grains/scf and has proposed to limit ammonia slip emissions to 5 ppmvd NH_3 @ 15% O_2.

Inlet air temperature and density directly affects turbine performance. Hotter and drier the inlet air temperatures result in lower turbine efficiencies and lower electrical generation capacities. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The proposed inlet air coolers 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 applicant has proposed the use of a lube oil coalescer. A 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 as pollutants in the turbine exhaust.

N-4597-4-2: Emergency Generator Engine

The engine is equipped with:

[x] Turbocharger
[x] Intercooler/aftercooler
[ ] Injection timing retard (or equivalent per District Policy SSP-1805, dated 8/14/1996)
[x] Positive Crankcase Ventilation (PCV) or 90% efficient control device
[ ] This engine is required to be, and is UL certified
[ ] Catalytic particulate filter
[x] Very Low (0.0015%) sulfur diesel

The emission control devices/technologies and their effect on diesel engine emissions detailed below are from *Non-catalytic NO_X Control of Stationary Diesel Engines*, by Don Koeberlein, CARB.

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 PCV system reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

The use of very low-sulfur diesel fuel (0.0015% by weight sulfur maximum) reduces SO_X emissions by over 99% from standard diesel fuel.

N-4597-5-0: Auxiliary Boiler

Ultra Low-NO_X burners reduce NO_X formation by producing lower flame temperatures (and longer flames) than conventional burners. Conventional burners thoroughly mix all the fuel and air in a single stage just prior to combustion, whereas low-NO_X burners delay the mixing of fuel and air by introducing the fuel (or sometimes the air) in multiple stages. Generally, in the first combustion stage, the air-fuel mixture is fuel rich. In a fuel rich environment, all the oxygen will be consumed in reactions with the fuel, leaving no excess oxygen available to react with nitrogen to produce thermal NO_X. In the secondary and tertiary stages, the combustion zone is maintained in a fuel-lean environment. The excess air in these stages helps to reduce the flame temperature so that the reaction between the excess oxygen with nitrogen is minimized.

The use of flue gas re-circulation (FGR) can reduce nitrogen oxides (NO_X) emissions by 60% to 70%. In an FGR system, a portion of the flue gas is re-circulated back to the inlet air. As flue gas is composed mainly of nitrogen and the products of combustion, it is much lower in oxygen than the inlet air and contains virtually no combustible hydrocarbons to burn. Thus, flue gas is practically inert. The addition of an inert mass of gas to the combustion reaction serves to absorb heat without producing heat, thereby lowering the flame temperature. Since thermal NO_X is formed by high flame temperatures, the lower flame temperatures produced by FGR serve to reduce thermal NO_X.

N-4597-6-0: Fire-Pump Engine

The engine is equipped with:

- [x] Turbocharger
- [x] Intercooler/aftercooler
- [ ] Injection timing retard (or equivalent per District Policy SSP-1805, dated 8/14/1996)
- [x] Positive Crankcase Ventilation (PCV) or 90% efficient control device
- [ ] This engine is required to be, and is UL certified
- [ ] Catalytic particulate filter
- [x] Very Low (0.0015%) sulfur diesel

The emission control devices/technologies and their effect on diesel engine emissions detailed below are from *Non-catalytic NO_X Control of Stationary Diesel Engines*, by Don Koeberlein, CARB.

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 PCV system reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

The use of very low-sulfur diesel fuel (0.0015% by weight sulfur maximum) reduces SO_X emissions by over 99% from standard diesel fuel.

VII. GENERAL CALCULATIONS:

A. Assumptions

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

- 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 500 hours 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 and CO are estimated assuming a worst-case scenario consisting of one cold start startup (3 hr), one hot startup (1 hr), two shutdowns (1.3 hr), and 18.7 hours of steady state operation at 15 degrees F ambient temperature and duct burners firing.
- Maximum daily emissions for each CTG for VOC, PM_{10}, and SOx are estimated assuming one cold startup (3 hr), one shutdown (0.6 hr) and 20.4 hours of steady state operation at 15 degrees F ambient temperature and duct burners firing.
- Maximum daily emissions for each CTG for NH_3 are estimated assuming 24 hours of steady state operation at 15 degrees F ambient temperature and duct burners firing.
- Maximum annual emissions for each CTG are estimated assuming each turbine has a maximum of 325 startups (25 cold, 50 warm, and 250 hot) and 325 shutdowns per year, 3,100 hours of operation with the evaporative coolers operating and duct burner firing and at an ambient temperature of 59 degrees F, and 4,900 hours of operation at base load with the evaporative coolers operating and no duct burner operating at an ambient temperature of 59 degrees F.

N-4597-4-2: Emergency Generator Engine

- Engine Operating Schedule: 24 hours/day
- Non-Emergency Operating Schedule: 200 hours/year (pre-project)
- Non-Emergency Operating Schedule: 50 hours/year (post-project)
- Density of diesel fuel: 7.1 lb/gal
- EPA F-Factor (adjusted to 60 °F): 9,051 dscf/MMBtu

- Fuel heating value: 137,000 Btu/gal
- BHP to Btu/hr conversion: 2,542.5 Btu/bhp-hr
- Thermal efficiency of engine: ≈ 35%
- PM_{10} fraction of diesel exhaust: 0.96 (CARB, 1988)

N-4597-5-0: Auxiliary Boiler

- The maximum operating schedule for the auxiliary boiler is 24 hours per day and 4,000 hours per year (per the applicant).
- The auxiliary boiler is fired solely on PUC regulated natural gas with a maximum daily sulfur content of 0.66 grains/100 SCF and an annual average sulfur content of 0.25 grains/100 SCF.
- Natural Gas Heating Value: 1,000 Btu/scf (District Practice)
- F-Factor for Natural Gas: 8,578 dscf/MMBtu corrected to 60 °F (40 CFR 60, Appendix B)

N-4597-6-0: Fire-Pump Engine

- Engine Operating Schedule: 24 hours/day
- Non-Emergency Operating Schedule: 50 hours/year
- Density of diesel fuel: 7.1 lb/gal
- EPA F-Factor (adjusted to 60 °F): 9,051 dscf/MMBtu
- Fuel heating value: 137,000 Btu/gal
- BHP to Btu/hr conversion: 2,542.5 Btu/bhp-hr
- Thermal efficiency of engine: ≈ 35%
- PM_{10} fraction of diesel exhaust: 0.96 (CARB, 1988)

B. Emission Factors

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

Pre-Project Turbine Steady State Emission Factors:

The following steady state pre-project hourly emissions factors were obtained from permits N-4597-1-4 and N-4597-2-4:

Pre-Project Steady State Emission Factors, Per Turbine						
	NO_X	CO	VOC	PM_{10}	SO_x	NH_3
Emissions Factor	5.0 ppmvd @ 15% O_2	6.0 ppmvd @ 15% O_2	2.0 ppmvd @ 15% O_2	3.3 lb/hr	0.78 lb/hr	10 ppmvd @ 15% O_2

Pre-Project Turbine Startup and Shutdown Emission Factors:

The following pre-project startup and shutdown emission factors were obtained from the engineering evaluation for project N-1011254.

Pre-Project Startup and Shutdown Emissions (20 min. startup, 30 min. shutdown), Per Turbine					
	PM_{10} (lb/event)	SO_x (lb/event)	NO_x (lb/event)	VOC (lb/event)	CO (lb/event)
Mass Emission Rate	2.6	N/A[(1)]	13.0	1.27[(2)]	21.0

Post-Project Turbine Commissioning Emission Factors:

During an initial commissioning phase, the turbine and duct burner will be operated at various firing rates without the benefit of the emission control systems to break-in plant equipment, to ensure proper operation of the HRSG and duct burners, to tune the SCR system's ammonia injection grid, and to perform final operational checks. VOC, PM10, and SOx emissions are not expected to be affected during commissioning since the firing rates for commissioning related tasks are generally very low; however, NOx and CO emissions will be elevated during commissioning since many of the tasks during commissioning must be completed prior to installation of the SCR and Oxidation catalysts. The applicant has proposed the following maximum hourly emission rates during commissioning, based on vendor data and best engineering estimates. See Attachment D for further details on the commissioning emissions.

Commissioning Period Emissions, Per Turbine					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (lb/hr)	146.70	229.60	3.20	5.80	2.60

[1] SO_X emissions during startups and shutdowns are always lower than maximum hourly emissions as SO_X emissions are proportional to fuel flow.
[2] No manufacturer startup or shutdown VOC emissions data are available. Therefore, the startup and shutdown emission rate is estimated based on the worst case scenario of a 30 minute portion of the maximum hourly emission rate at 2.0 ppmvd @ 15% O_2 as follows: 2.54 lb/hr × 30/60 hr = 1.27 lb/event.

Post-Project Turbine Steady State Emissions Factors (without duct burner):

The applicant has provided emissions data for the turbines, when firing without the duct burner at 100% load. See Attachment E for further information on the steady state emissions.

Steady State Emission Factors Without Duct Burner, per Turbine					
	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
%Load	100%	100%	100%	100%	100%
Inlet Air Cooling	No	Yes	No	Yes	No
Ambient Temperature	59 F	59 F	115 F	115 F	15 F
Max Firing Rate (MMBtu/hr)	974	991	826	895	1091
NOx (ppmvd @ 15 % O_2)	2.0	2.0	2.0	2.0	2.0
NOx (lb/hr)	7.20	7.30	6.20	6.70	8.10
CO (ppmvd @ 15% O_2)	2.0	2.0	2.0	2.0	2.0
CO (lb/hr)	3.50	3.60	3.00	3.20	3.90
SO_x (lb/hr) (based on 0.25 grains/100 scf)	0.68	0.70	0.58	0.63	0.77
VOC ppmvd @ 15% O_2	1.0	1.0	1.0	1.0	1.0
VOC (lb/hr)	1.02	1.04	0.90	0.95	1.13
PM10 (lb/MMBtu)	0.0034	0.0034	0.0039	0.0037	0.0031
PM10 (lb/hr)	3.30	3.30	3.30	3.30	3.40
NH_3 (ppmvd)	5	5	5	5	5
NH_3 (lb/hr)	6.45	6.60	5.50	5.95	7.25

The scenario with the highest emission rates, scenario #5, is used to determine the worst-case hourly and daily emissions. For annual emissions, scenario #2 was chosen as this scenario is more representative of the actual average conditions for the turbine on an annual basis.

Post Project Turbine Steady State Emission factors (with duct burner):

The applicant has provided emissions data for the turbines, when firing with the duct burner at 100% load. See Attachment E for further information on the steady state emission factors.

Steady State Emission Factors With Duct Burner, per Turbine			
	Scenario 1	Scenario 2	Scenario 3
%Load	100%	100%	100%
Inlet Air Cooling	Yes	Yes	Yes
Ambient Temperature	59 F	115 F	15 F
Max Firing Rate (MMBtu/hr)	1,315	1,219	1,415
NOx (ppmvd @ 15 % O_2)	2.0	2.0	2.0
NOx (lb/hr)	9.60	8.90	10.30
CO (ppmvd @ 15% O_2)	2.0	2.0	2.0
CO (lb/hr)	5.70	5.30	6.00
SO_x (lb/hr) (based on 0.25 grains/100 scf)	0.92	0.86	1.0
VOC ppmvd @ 15% O_2	2.0	2.0	2.0
VOC (lb/hr)	3.13	3.05	3.22
PM10 (lb/MMBtu)	0.0033	0.0035	0.0031
PM10 (lb/hr)	4.40	4.30	4.40
NH_3 (ppmvd)	5	5	5
NH_3 (lb/hr)	8.75	8.10	9.40

The scenario with the highest emission rates, scenario #3, is used to determine the worst-case hourly and daily emissions. For annual emissions, scenario #1 was chosen as this scenario is more representative of the actual average conditions for the turbine on an annual basis.

Post-Project Turbine Startup and Shutdown Emission Factors:

The startup and shutdown emission factors are shown below. Please refer to Attachment F for further information on the startup and shutdown emissions.

Hot Startup Emission Factors, Per Turbine			
	Scenario 1	Scenario 2	Scenario 3
Ambient Temperature	15 F	59 F	115 F
Relative Humidity	100%	60%	30%
Duration	61 min	61 min	61 min
NOx (lb/startup)	24	14.5	24
CO (lb/startup)	101	46.5	71.5
VOC (lb/startup)	1.7	0.75	1.05
SOx (lb/startup)	1.25	1.1	0.9
PM10 (lb/startup)	3.0	3.4	3.8

Warm Startup Emission Factors, Per Turbine			
	Scenario 1	Scenario 2	Scenario 3
Ambient Temperature	15 F	59 F	115 F
Relative Humidity	100%	60%	30%
Duration	118 min	118 min	118 min
NOx (lb/startup)	241.5	81	224.5
CO (lb/startup)	349	160	331.5
VOC (lb/startup)	6.5	1.9	5
SOx (lb/startup)	2.5	2.35	1.8
PM10 (lb/startup)	6.8	6.8	10

Cold Startup Emission Factors, Per Turbine			
	Scenario 1	Scenario 2	Scenario 3
Ambient Temperature	15 F	59 F	115 F
Relative Humidity	100%	60%	30%
Duration	180 min	180 min	180 min
NOx (lb/startup)	390.5	126.5	367.5
CO (lb/startup)	562.5	143	531.5
VOC (lb/startup)	10.5	3.05	8
SOx (lb/startup)	4.1	3.75	3.25
PM10 (lb/startup)	11	11	11

Proposed Worst Case Hourly Emissions During Startup, Per Turbine	
NOx (lb/hr)	199.50
CO (lb/hr)	187.50
VOC (lb/hr)	5.50
SOx (lb/hr)	2.45
PM10 (lb/hr)	4.70

Shutdown Emission Factors, Per Turbine			
	Scenario 1	Scenario 2	Scenario 3
Ambient Temperature	15 F	59 F	115 F
Relative Humidity	100%	60%	30%
Duration	39 min	39 min	39 min
NOx (lb/shutdown)	104	38.5	100
CO (lb/shutdown)	148	49.5	141
VOC (lb/shutdown)	2.6	0.85	2.1
SOx (lb/shutdown)	0.85	1.05	0.9
PM10 (lb/shutdown)	3.0	3.0	3.0

Proposed Worst Case Hourly Emissions During Shutdown, Per Turbine	
NOx (lb/hr)	106.00
CO (lb/hr)	149.00
VOC (lb/hr)	3.15
SOx (lb/hr)	1.23
PM10 (lb/hr)	3.77

N-4597-4-2: Emergency Generator Engine

Pre and Post-Project Emergency Generator IC Engine Emission Factors		
Pollutant	**Emission Factor (g/bhp-hr)**	**Source**
NO_X	4.69	PTO N-4597-4-1
SO_X	0.0051	Mass Balance Equation Below
PM_{10}	0.029	PTO N-4597-4-1
CO	0.12	PTO N-4597-4-1
VOC	0.04	PTO N-4597-4-1

$$\frac{0.000015\,lb-S}{lb-fuel}\times\frac{7.1\,lb-fuel}{gallon}\times\frac{2\,lb-SO_2}{1\,lb-S}\times\frac{1\,gal}{137{,}000\,Btu}\times\frac{1\,bhp\,input}{0.35\,bhp\,out}\times\frac{2{,}542.5\,Btu}{bhp-hr}\times\frac{453.6\,g}{lb}=0.0051\ \frac{g-SO_x}{bhp-hr}$$

N-4597-5-0: Auxiliary Boiler

Proposed Auxiliary Boiler Post-Project Emission Factors				
Pollutant	**Post-Project Emission Factors**			**Source**
NO_X	7.3 lb-NO_X/MMscf	0.0073 lb-NO_X/MMBtu	6 ppmvd NO_X (@ 3%O_2)	Applicant
SOx (daily)[3]	1.9 lb-SOx/MMscf	0.0019 lb-SOx/MMBtu		Applicant
SO_X (annual)[4]	0.7 lb-SO_X/MMscf	0.0007 lb-SO_X/MMBtu		Applicant
PM10	7.0 lb-PM10/MMscf	0.007 lb-PM10/MMBtu		Applicant
CO	37 lb-CO/MMscf	0.037 lb-CO/MMBtu	50 ppmvd CO (@ 3%O_2)	Applicant
VOC	0.005	0.005 lb-VOC/MMBtu		Applicant

N-4597-6-0: Fire-Pump Engine

Proposed Fire Pump IC Engine Post-Project Emission Factors		
Pollutant	**Emission Factor (g/bhp-hr)**	**Source**
NO_X	2.67	Engine Manufacturer
SO_X	0.0051	Mass Balance Equation Below
PM_{10}	0.12	Engine Manufacturer
CO	2.39	Engine Manufacturer
VOC	0.16	Engine Manufacturer

$$\frac{0.000015\,lb-S}{lb-fuel}\times\frac{7.1\,lb-fuel}{gallon}\times\frac{2\,lb-SO_2}{1\,lb-S}\times\frac{1\,gal}{137{,}000\,Btu}\times\frac{1\,bhp\ input}{0.35\,bhp\ out}\times\frac{2{,}542.5\,Btu}{bhp-hr}\times\frac{453.6\,g}{lb}=0.0051\ \frac{g-SO_x}{bhp-hr}$$

[3] The District typically uses an emissions factor of 0.00285 lb/MMBtu for PUC quality gas that contains less than 1.0 grains S/100 scf; however, this facility utilizes PUC quality gas that has a daily maximum value of 0.66 grains S/100 scf.
0.66 grains S/scf x (0.00285 lb/MMBtu ÷ 1.0 grains S/100 scf) = 0.0019 lb-SOx/MMBtu

3

The District typically uses an emissions factor of 0.00285 lb/MMBtu for PUC quality gas that contains less than 1.0 grains S/100 scf; however, this facility utilizes PUC quality gas that on an annual average contains only 0.25 grains S/100 scf.
0.25 grains S/scf x (0.00285 lb/MMBtu ÷ 1.0 grains S/100 scf) = 0.0007 lb-SOx/MMBtu

C. Calculations

1. Pre-Project Potential to Emit (PE1)

a. Maximum Pre-Project Hourly PE

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

The maximum pre-project startup and shutdown hourly emissions were derived using the maximum startup and shutdown emission rates (lb/event) listed in the engineering evaluation for project N-1011245, assuming a startup and shutdown period of 1 hour. The maximum pre-project steady state hourly emissions were obtained from the current permit to operate, except for the NH_3 hourly emissions rate that was obtained from the engineering evaluation for project N-1011245.

Pre-Project Hourly Potential to Emit, Per Turbine			
	Startup	**Shutdown**	**Maximum Steady State**
NOx (lb/hr)	39.00	26.00	26.45
CO (lb/hr)	3.81	2.54	26.57
VOC (lb/hr)	63.00	42.0	2.42
PM10 (lb/hr)	N/A	N/A	3.3
SOx (lb/hr)	N/A	N/A	0.78
NH_3 (lb/hr)	N/A	N/A	13.19

N-4597-4-2: Emergency Generator Engine

Pre-Project Hourly Potential to Emit				
Pollutant	**Emissions Factor (g/bhp-hr)**	**Rating (bhp)**	**Conversion (g/lb)**	**PE1 Total (lb/hr)**
NO_X	4.69	471	453.6	4.87
SO_X	0.0051	471	453.6	0.01
PM_{10}	0.029	471	453.6	0.03
CO	0.12	471	453.6	0.12
VOC	0.04	471	453.6	0.04

N-4597-5-0: Auxiliary Boiler

This is a new unit; therefore, PE1 is equal to zero.

N-4597-6-0: Fire-Pump Engine

This is a new unit; therefore, PE1 is equal to zero.

b. Maximum Pre-Project Daily PE

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

The maximum pre-project daily potential to emit for the existing combustion turbine generators was obtained from the engineering evaluation for project N-1062415.

Pre-Project Daily Potential to Emit, Per Turbine	
	Daily PE1
NOx (lb/day)	493.3
CO (lb/day)	18.7
VOC (lb/day)	80.0
PM10 (lb/day)	235.7
SOx (lb/day)	42.4
NH_3 (lb/day)	316.6

N-4597-4-2: Emergency Generator Engine

Pre-Project Daily Potential to Emit					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Daily Hours of Operation (hrs/day)	Conversion (g/lb)	Total PE (lb/day)
NO_X	4.69	471	24	453.6	116.9
SO_X	0.0051	471	24	453.6	0.1
PM_{10}	0.029	471	24	453.6	0.7
CO	0.12	471	24	453.6	3.0
VOC	0.04	471	24	453.6	1.0

N-4597-5-0: Auxiliary Boiler

This is a new unit; therefore, PE1 is equal to zero.

N-4597-6-0: Fire-Pump Engine

This is a new unit; therefore, PE1 is equal to zero.

c. Maximum Pre-Project Annual PE

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

The maximum pre-project annual potential to emit was obtained from the engineering evaluation for project N-1062415.

Pre-Project Annual Potential to Emit, Per Turbine	
	Annual PE1
NOx (lb/day)*	153,460
CO (lb/day)	71,620
VOC (lb/day)*	13,356
PM10 (lb/day)*	26,667
SOx (lb/day)	5,600
NH_3 (lb/day)	105,520

* Note, permits N-4597-1-4 and N-4597-2-4 limit the combined annual emissions for NOx, VOC, and PM10. The combined annual emissions limits have been divided by two in order to determine a maximum pre-project potential to emit for each turbine.

N-4597-4-2: Emergency Generator Engine

Pre-Project Annual Potential to Emit					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Annual Hours of Operation (hrs/year)	Conversion (g/lb)	PE1 Total (lb/year)
NO_X	4.69	471	200	453.6	974
SO_X	0.0051	471	200	453.6	1
PM_{10}	0.029	471	200	453.6	6
CO	0.12	471	200	453.6	25
VOC	0.04	471	200	453.6	8

N-4597-5-0: Auxiliary Boiler

This is a new unit; therefore, PE1 is equal to zero.

N-4597-6-0: Fire-Pump Engine

This is a new unit; therefore, PE1 is equal to zero.

2. Post Project Potential to Emit (PE2)

a. Maximum Post-Project Hourly PE

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

The maximum hourly emission rate is used for Risk Management Review modeling and for Ambient Air Quality analysis modeling. The maximum hourly emission rate was determined by comparing the worst case commissioning, startup, shutdown, steady state (w/duct burner) and steady state (w/o duct burner) emission rates. The maximum hourly emission rate for each turbine is summarized in the table below, with the absolute maximum values designated in bold font.

Post-Project Hourly Potential to Emit, per Turbine					
	Commissioning*	**Startup***	**Shutdown***	**Maximum Steady State with Duct Burner****	**Maximum Steady State W/O Duct Burner*****
NOx (lb/hr)	146.70	**199.50**	106.00	10.30	8.10
CO (lb/hr)	**229.60**	187.50	149.00	6.00	3.90
VOC (lb/hr)	3.20	**5.50**	3.15	3.22	1.13
PM10 (lb/hr)	**5.80**	4.70	3.75	**5.80**[5]	4.40[5]
SOx (lb/hr)	**2.60**	2.45	1.25	2.63[5]	2.02[5]
NH_3 (lb/hr)	N/A	N/A	N/A	**9.40**	7.25

*The commissioning, startup, and shutdown emission rates were obtained from the post-project emission factors section of this document.
**The maximum steady state emission rates with the duct burners operating, was obtained from scenario 3 of the post-project emission factors table listed earlier in this project. Worst-case PM10 and SOx emissions were obtained later from the applicant and reflect the maximum short-term fuel sulfur content limit.
*** The maximum steady state emission rates without the duct burners operating, was obtained from scenario 5 of the post-project emission factors table listed earlier in this project. Worst-case PM10 and SOx emissions were obtained later from the applicant and reflect the maximum short-term fuel sulfur content limit.

N-4597-4-2: Emergency Generator Engine

Post-Project Hourly Potential to Emit				
Pollutant	**Emissions Factor (g/bhp-hr)**	**Rating (bhp)**	**Conversion (g/lb)**	**PE2 Total (lb/hr)**
NO_X	4.69	471	453.6	4.87
SO_X	0.0051	471	453.6	0.01
PM_{10}	0.029	471	453.6	0.03
CO	0.12	471	453.6	0.12
VOC	0.04	471	453.6	0.04

N-4597-5-0: Auxiliary Boiler

Post-Project Hourly Potential to Emit			
Pollutant	**Emissions Factor (lb/MMBtu)**	**Heat Input (MMBtu/hr)**	**Hourly PE2 (lb/hr)**
NOx	0.0073	85.0	0.62
SOx[5]	0.0019	85.0	0.16
PM10	0.007	85.0	0.60
CO	0.037	85.0	3.15
VOC	0.005	85.0	0.43

[5] Maximum hourly SOx emissions for the turbines and boiler are based upon the short-term maximum natural gas sulfur content of 0.66 grains/100 scf. The higher short term SOx limit also affects the hourly PM10 emission rates. Therefore, the PM10 rates listed are higher than those listed in the emissions factors section of this document, which are based on a fuel sulfur content of 0.25 grains/100 scf.

N-4597-6-0: Fire-Pump Engine

Post-Project Hourly Potential to Emit				
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Conversion (g/lb)	PE2 Total (lb/hr)
NO_X	2.67	288	453.6	1.70
SO_X	0.0051	288	453.6	0.003
PM_{10}	0.12	288	453.6	0.08
CO	2.39	288	453.6	1.52
VOC	0.16	288	453.6	0.10

b. *Maximum Post-Project Daily PE*

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

The maximum daily potential to emit for each turbine was calculated using the following assumptions:

1. Maximum daily emissions for each CTG for NO_X and CO are estimated assuming a worst-case scenario consisting of one cold start startup (3 hr), one hot startup (1 hr), two shutdowns (1.3 hr), and 18.7 hours of steady state operation at 15 degrees F ambient temperature with the evaporative coolers operating and duct burners firing.

2. Maximum daily emissions for each CTG for VOC, PM_{10}, and SOx are estimated assuming one cold startup (3 hr), one shutdown (0.6 hr) and 20.4 hours of steady state operation at 15 degrees F ambient temperature with the evaporative coolers operating and duct burners firing.

3. Maximum daily emissions for each CTG for NH_3 are estimated assuming 24 hours of steady state operation at 15 degrees F ambient temperature with the evaporative coolers operating and duct burners firing.

The results of the maximum post-project daily potential to emit calculations are shown in the table below. More information on the daily emissions calculations is available in Attachment G.

Post-Project Daily Potential to Emit, Per Turbine						
	NOx	CO	VOC	SOx	PM10	NH_3
Cold Startup Emissions (lb/day)	390.5	562.5	10.5	4.1	11.0	0.0
Hot Startup Emissions (lb/day)	24.0	101.0	0.0	0.0	0.0	0.0
Shutdown Emissions (lb/day)	208.0	296.0	2.6	1.1	3.0	0.0
Normal Operation emissions (lb/day)	192.4	112.1	65.5	53.5[6]	118.0	225.6
Total Emissions (lb/day)	**814.9**	**1071.6**	**78.6**	**58.7**	**132.0**	**225.6**

[6] Maximum daily SOx emissions for the turbines are based upon the short-term maximum natural gas sulfur content of 0.66 grains/100 scf.

N-4597-4-2: Emergency Generator Engine

Post-Project Daily Potential to Emit					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Daily Hours of Operation (hrs/day)	Conversion (g/lb)	PE2 Total (lb/day)
NO_X	4.69	471	24	453.6	116.9
SO_X	0.0051	471	24	453.6	0.1
PM_{10}	0.029	471	24	453.6	0.7
CO	0.12	471	24	453.6	3.0
VOC	0.04	471	24	453.6	1.0

N-4597-5-0: Auxiliary Boiler

Post-Project Daily Potential to Emit				
Pollutant	Emissions Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Daily Hours of Operation (hrs/day)	PE2 Total (lb/day)
NOx	0.0073	85.0	24	14.9
SOx[7]	0.0019	85.0	24	3.8
PM10	0.007	85.0	24	14.3
CO	0.037	85.0	24	75.5
VOC	0.005	85.0	24	10.2

N-4597-6-0: Fire-Pump Engine

Post-Project Daily Potential to Emit					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Daily Hours of Operation (hrs/day)	Conversion (g/lb)	PE2 Total (lb/day)
NO_X	2.67	288	24	453.6	40.7
SO_X	0.0051	288	24	453.6	0.1
PM_{10}	0.12	288	24	453.6	1.8
CO	2.39	288	24	453.6	36.4
VOC	0.16	288	24	453.6	2.4

c. *Maximum Annual PE*

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

The maximum annual potential to emit for each turbine was calculated using the following assumptions:

[7] Maximum daily SOx emissions for the boiler are based upon the short-term maximum natural gas sulfur content of 0.66 grains/100 scf. higher than those listed in the emissions factors section of this document, which are based on a fuel sulfur content of 0.25 grains/100 scf.

1. Maximum annual emissions for each CTG are estimated assuming a worst-case scenario of 325 startups (25 cold, 50 warm, and 250 hot) and 325 shutdowns per year, 3,100 hours of operation with the evaporative coolers operating and duct burner firing and at an ambient temperature of 59 degrees F, and 4900 hours of operation at base load with the evaporative coolers operating and no duct burner operating at an ambient temperature of 59 degrees F. Please refer to attachment G for further annual potential to emit information.

Post-Project Annual Potential to Emit, per Turbine						
	NOx	CO	VOC	SOx	PM10	NH_3
Cold Startup (lb/year)	3,163	3,575	76	94	275	0
Warm Startup (lb/year)	4,050	8,000	95	118	340	0
Hot Startup (lb/year)	3,625	11,625	188	275	850	0
Shutdown (lb/year)	12,513	16,088	276	341	975	0
Normal Operation w/duct burner (lb/year)	29,760	17,670	9,610	2,855[8]	13,640	27,125
Normal Operation w/o duct burner (lb/year)	35,770	17,640	4,900	3,401[8]	16,170	32,340
Total Emissions (lb/year)	**88,881**	**74,598**	**15,145**	**7,084**	**32,250**	**59,456**

N-4597-4-2: Emergency Generator Engine

Post-Project Annual Potential to Emit					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Annual Hours of Operation (hrs/year)	Conversion (g/lb)	PE2 Total (lb/year)
NO_X	4.69	471	50	453.6	243
SO_X	0.0051	471	50	453.6	0
PM_{10}	0.029	471	50	453.6	2
CO	0.12	471	50	453.6	6
VOC	0.04	471	50	453.6	2

N-4597-5-0: Auxiliary Boiler

Post-Project Annual Potential to Emit				
Pollutant	Emissions Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Annual Hours of Operation (hrs/yr)	PE2 Total (lb/year
NOx	0.0073	85.0	4,000	2,482
SOx	0.0007	85.0	4,000	238
PM10	0.007	85.0	4,000	2,380
CO	0.037	85.0	4,000	12,580
VOC	0.005	85.0	4,000	1,700

[8] Maximum annual SOx emissions for the turbines and boiler are based upon the annual average natural gas sulfur content of 0.25 grains/100 scf.

N-4597-6-0: Fire-Pump Engine

Post-Project Annual Potential to Emit					
Pollutant	**Emissions Factor (g/bhp-hr)**	**Rating (bhp)**	**Annual Hours of Operation (hrs/year)**	**Conversion (g/lb)**	**PE2 Total (lb/year)**
NO_X	2.67	288	50	453.6	85
SO_X	0.0051	288	50	453.6	0
PM_{10}	0.12	288	50	453.6	4
CO	2.39	288	50	453.6	76
VOC	0.16	288	50	453.6	5

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. Note, no Emission Reduction have been banked at this source.

<table>
<tr><th colspan="7">Pre-project Stationary Source Potential to Emit [SSPE1]</th></tr>
<tr><th>Permit Unit</th><th>NO_X (lb/year)</th><th>CO (lb/year)</th><th>VOC (lb/year)</th><th>PM_{10} (lb/year)</th><th>SO_X (lb/year)</th><th>NH_3 (lb/year)</th></tr>
<tr><td>N-4597-1-4</td><td rowspan="2">306,920</td><td>71,620</td><td rowspan="2">26,712</td><td rowspan="2">53,334</td><td>5,600</td><td>105,520</td></tr>
<tr><td>N-4597-2-4</td><td>71,620</td><td>5,600</td><td>105,520</td></tr>
<tr><td>N-4597-4-1</td><td>974</td><td>25</td><td>8</td><td>6</td><td>1</td><td>0</td></tr>
<tr><td>SSPE1</td><td>307,894</td><td>143,265</td><td>26,720</td><td>53,340</td><td>11,201</td><td>211,040</td></tr>
</table>

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. Note, no Emission Reduction have been banked at this source.

Post-project Stationary Source Potential to Emit [SSPE2]						
Permit Unit	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)	NH_3 (lb/year)
N-4597-1-5	88,881	74,598	15,145	32,250	7,084	59,465
N-4597-2-5	88,881	74,598	15,145	32,250	7,084	59,465
N-4597-4-2	243	6	2	2	0	0
N-4597-5-0	2,482	12,580	1,700	2,380	238	0
N-4597-6-0	85	76	5	4	0	0
SSPE2	**180,572**	**161,858**	**31,997**	**66,884**	**14,406**	**118,930**

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)
Pre-Project SSPE (SSPE1)	307,894	143,265	26,720	53,340	11,201
Post-project SSPE (SSPE2)	180,572	161,858	31,997	66,884	14,406
Major Source Threshold	50,000	200,000	50,000	140,000	140,000
Major Source?	**Yes**	No	No	No	No
New Major Source?	No	No	No	No	No

6. Baseline Emissions (BE)

The BE calculation (in lbs/year) is performed pollutant-by-pollutant for each unit within the project, to calculate the QNEC and if applicable, to determine the amount of offsets required.

Pursuant to Section 3.7 of District Rule 2201,

BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE)

a. BE NO_X

This facility is a major source for NOx emissions; therefore the units must be either clean, highly utilized, or fully offset in order for BE to equal PE1.

Pursuant to Rule 2201, Section 3.12, a Clean Emissions Unit is defined as an emissions unit that is "equipped with an emissions control technology with a minimum control efficiency of at least 95% or is equipped with emission control technology that meets the requirements for achieved-in-practice BACT as accepted by the APCO during the five years immediately prior to the submission of the complete application.

This project was deemed complete on August 22, 2008. Therefore, each unit must meet the achieved-in-practice BACT as accepted by the APCO for any time from August 23, 2003, through August 23, 2008 in order to be considered clean emission units.

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

Current BACT Guideline 3.4.7 (See Attachment H) applies to the existing peaking power plant. Guideline 3.4.7 lists an achieved-in-practice limit of 5.0 ppmvd @ 15% O_2 for NOx emissions. Current Permits N-4597-1-4 and N-4597-2-4 limit NOx emissions to 5.0 ppmvd @ 15% O_2; therefore, each of the turbines qualify as a clean emission unit for NOx. For each unit:

$BE_{NOx} = PE1_{NOx}$

N-4597-4-2: Emergency Generator Engine

Current BACT Guideline 3.1.3 (See Attachment L) applies to the existing 471 HP emergency engine powering a generator. Guideline 3.1.3 requires certified emissions of 6.9 g-NO_x/bhp-hr or less (achieved-in-practice). The current emergency generator engine meets this limit; therefore, the engine qualifies as a clean emission unit for NOx.

$BE_{NOx} = PE1_{NOx}$

N-4597-5-0: Auxiliary Boiler

This is a new unit. Therefore, $BE_{NOx} = 0$

N-4597-6-0: Fire-Pump Engine

This is a new unit. Therefore, $BE_{NOx} = 0$

b. BE CO

This facility is minor source for CO emissions; therefore the BE_{CO} is set equal $PE1_{CO}$.

$BE_{CO} = PE1_{CO}$

c. BE VOC

This facility is minor source for VOC emissions; therefore the BE_{VOC} is set equal $PE1_{VOC}$.

$BE_{VOC} = PE1_{VOC}$

d. BE SO_X

This facility is minor source for SO_x emissions; therefore the BE_{SOx} is set equal $PE1_{SOx}$.

$BE_{SOx} = PE1_{SOx}$

e. BE PM_{10}

This facility is minor source for PM_{10} emissions; therefore the BE_{PM10} is set equal $PE1_{PM10}$.

$BE_{PM10} = PE1_{PM10}$

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 (in effect 12/19/02) 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.*"

As discussed in Section VII.C.5 above, the facility is only a Major Source for NOx emissions. Therefore, a major modification can only be triggered for NOx emissions.

The first step in determing whether the project triggers a major modification is to compare the Project PE2 with the Major Modification significance thresholds listed in District Rule 2201. If the project PE2 is less than the corresponding significance threshold for a pollutant, a major modification cannot be triggered for that pollutant and further calculations are not necessary. Since the Project PE2 is greater than the significance thresholds for NOx, further investigation is required to determine whether the project is a major modification for NOx.

Major Modification Thresholds (Existing Major Source)			
Pollutant	Project PE2 (lb/year)	Major Modification Threshold (lb/year)	Further Major Modification Calculations Necessary?
NO_x	181,572	50,000	**Yes**

The second step in determining whether the project triggers a major modification is to calculate the Net Emissions Increase (NEI) for the project, and compare that to the Major Modification thresholds.

The Net Emissions Increase (NEI) for this project will be calculated as follows:

NEI = Post-Project Actual Emissions – Pre-Project Actual Emissions

The pre-project actual emissions for NO_x are based on the data for the latest 2 years from the District's emission inventory for GWF Tracy (see Attachment I). As shown below, this project triggers a major modification for NOx.

Net Emissions Increase					
Pollutant	Project PE2 (lb/year)	Actual Emissions (2006/2007) (lb/year)	Net Emissions Increase (lb/year)	Threshold (lb/year)	Major Modification?
NO_x	181,572	3,514	178,058	50,000	**Yes**

Since a Major Modification is triggered for NOx emissions, BACT is required for NOx from each emissions unit included in the project. As well, any project that triggers a major modification is considered to be a significant modification per District Rule 2520. Thus, EPA, CARB, and public notices are required.

8. Federal Major Modification

As shown above, this project is not a major modification for PM10, VOC, and SOx emissions. Therefore, a Federal major modification cannot be triggered for those pollutants. Further calculations are necessary to determine whether the project triggers a Federal Major Modification for NOx emissions.

A Federal Major Modification is triggered if the project meets the definition of Major Modification listed in the current version of 40 CFR 51.165. In the latest version of 40 CFR 51.165, Major Modification (current) is defined as *any physical change in or change in the method of operation of a major stationary source that would result in:*

(1) A significant increase in emissions of a regulated NSR pollutant; and
(2) A significant net emissions increase of that pollutant from the major stationary source.

Pursuant to paragraph (a)(2)(ii)(C) of 40 CFR 51.165, a significant modification of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions and the baseline actual emissions for each existing emissions unit equals or exceeds the significance thresholds.

NEI = Projected Actual Emissions – Baseline Actual Emissions

Pursuant to the CFR, projected actual emissions may be set equal to the emission unit's potential to emit. For the purposes of calculating the Net Emissions Increase for this project, the projected actual emissions will be set equal to the post-project potential to emit.

Baseline actual emissions are defined in the current version of 40 CFR 51.165 as the rate of emissions of a regulated NSR Pollutant as determined in paragraphs (a)(1)(xxxv)(A)(D) of 40 CFR 51.165.

For any existing emissions unit that is not an electric utility steam generating unit, baseline actual emissions means the average rate at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction or the date a complete permit application is received by the reviewing authority, whichever is earlier.

Based on the District's emission inventory for GWF Tracy, the 2003 and 2004 years had the highest NOx emissions. Therefore, those years have conservatively been chosen as the baseline actual emissions period. Please refer to Attachment I for more actual emissions information for 2003/2004.

Net Emissions Increase					
Pollutant	Project PE2 (lb/year)	Baseline Actual Emissions (lb/year)	Net Emissions Increase (lb/year)	Threshold (lb/year)	Federal Major Modification?
NO_x	181,572	4,132	177,440	50,000	**Yes**

As shown above, this project triggers a Federal Major Modification for NOx.

9. QNEC

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Attachment J.

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.

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

The two CTG's 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 monitor emissions during all types of operation, including during startup and shutdown periods, 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 60.4335(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 Specifications 2, 3, and 4, and/or 40 CFR 75 Appendix A, 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, or 40 CFR Part 75 Appendix B, at least once every four calendar quarters. The owner/operator 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. If the RATA test is conducted as specified in 40 CFR Part 75 Appendix B, the RATA shall be conducted on a lb/MMBtu basis. [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 and 40 CFR 60.4350(a)]

- 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 owner/operator 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 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]

N-4597-4-2: Emergency Generator Engine

This unit is not required to be equipped with a CEM; therefore, Rule 1080 requirements are not applicable.

N-4597-5-0: Auxiliary Boiler

The boiler will either be equipped with an operational CEMs for NO_X, CO, and O_2 or will be monitored via a District pre-approved alternate monitoring plan as allowed by District Rule 4320. The applicant will be required to report the chosen monitoring scheme to the District at least 30 days prior to initial operation of the boiler. At that time, the appropriate CEMs or alternate monitoring scheme provisions will be added to the permit. 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 exhaust stack shall either be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2 or the owner/operator shall implement one of the alternate monitoring schemes (A, B, C, D, E, F, or G) listed in District Rule 4320 Section 5.7.1 (dated 10/16/08) . Owner/operator shall submit, in writing, the chosen method of monitoring (either CEMS or chosen alternate monitoring scheme) at least 30 days prior to initial operation of this boiler. [District Rules 1080 and 2201]

N-4597-6-0: Fire-Pump Engine

This unit is not required to be equipped with a CEM; therefore, Rule 1080 requirements are not applicable.

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.

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

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

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_X, CO, and O_2 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 the steady state NOx, CO, VOC, and NH3 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, 2201 and 4703 and 40 CFR 60.4400]
- Source testing to measure the PM10 emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081, 2201 and 40 CFR 60.4400]
- Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (N-4597-1 or N-4597-2) within 60 days after the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NO_X and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081 and 2201]
- Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703]

- Testing to demonstrate compliance with the short-term (daily) fuel sulfur content limit shall be conducted monthly. If a monthly test indicates that a violation of the daily fuel sulfur content limit has occurred then weekly testing shall commence and continue until eight consecutive tests show compliance. Once compliance with the daily fuel sulfur content is demonstrated on eight consecutive weekly tests, testing may return to the monthly schedule. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. [District Rule 2201 an 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

- Compliance with the rolling 12-month rolling average fuel sulfur content limit shall be demonstrated monthly. The 12-month rolling average fuel sulfur content shall be calculated as follows: 12-month rolling average fuel sulfur content = Sum of the monthly average fuel sulfur contents for the previous 12 months ÷ total number of months the unit has operated in during the previous 12 months. The monthly average fuel sulfur content is the average fuel sulfur content of all tests conducted in a given month. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. Owner/operator shall keep a monthly record of the rolling 12-month average fuel sulfur content. [District Rules 1081 and 2201]

- 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)]

- 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: NOx - EPA Method 7E, 20, or ARB Method 100 and EPA Method 19 (Acid Rain Program); CO - EPA Method 10 or 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 and 202 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, 20, or ARB Method 100. NOx testing shall also be conducted in accordance with the requirements of 40 CFR 60.4400(a)(2), (3), and (b). 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) and 40 CFR 60.4400(a)(2), (3), and (b)]

N-4597-4-2: Emergency Generator Engine

This unit is not required to be source tested; therefore, District Rule 1080 requirements are not applicable.

N-4597-5-0: Auxiliary Boiler

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

Proposed Rule 1081 Conditions:

- 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]

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

N-4597-6-0: Fire-Pump Engine

This unit is not required to be source tested; therefore, District Rule 1080 requirements are not applicable.

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.

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

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

Proposed Rule 1100 Conditions:

- Owner/operator 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]

N-4597-4-2: Emergency Generator Engine

Per District Practice, breakdown requirements are not included on emergency engine permits.

N-4597-5-0: Auxiliary Boiler

Per District Practice, breakdown requirements are not included on boiler permits.

N-4597-6-0: Fire-Pump Engine

Per District Practice, breakdown requirements are not included on emergency engine permits.

Rule 2010 Permits Required

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

Rule 2020 Exemptions

The modification of the existing peaker power plant includes the addition of a new 3,284 gal/minute water cooling tower. District Rule 2020 Section 6.2 categorically exempts water cooling towers that have a circulation rate of less than 10,000 gallons per minute and that are not used for cooling of process water, water from barometric jets, or water from barometric condensers. The proposed cooling tower meets the qualifications to be considered categorically exempt and a permit is not required.

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (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.

a. New emissions units – PE > 2 lb/day

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

Although the turbine units are being modified in the project, for BACT purposes these units will be treated as new since the class and category of the units is changing.

New Emissions Unit BACT Applicability				
Pollutant	**Daily Emissions for Each Turbine (lb/day)**	**BACT Threshold (lb/day)**	**SSPE2 (lb/yr)**	**BACT Triggered?**
NO_X	814.9	> 2.0	n/a	Yes
SO_X	58.7	> 2.0	n/a	Yes
PM_{10}	132.0	> 2.0	n/a	Yes
CO	1071.6	> 2.0 and SSPE2 ≥ 200,000 lb/yr	161,858	No
VOC	78.6	> 2.0	n/a	Yes
NH_3	225.6	> 2.0	n/a	No*

* The PE of ammonia (NH_3) exceeds 2.0 lb/day. However, the ammonia emissions are intrinsic to the operation of the selective catalytic reduction (SCR) system, which is BACT for NO_x emissions. Emissions from a control device that is determined by the District to be BACT are not subject to BACT.

Thus BACT will be triggered for NO_X, SO_X, PM_{10}, and VOC emissions from each turbine.

N-4597-4-2: Emergency Generator Engine

This is a modified unit, thus BACT cannot be triggered for installation of a new unit with emissions greater than 2.0 lb/day.

N-4597-5-0: Auxiliary Boiler

New Emissions Unit BACT Applicability				
Pollutant	**Daily Emissions for Boiler (lb/day)**	**BACT Threshold (lb/day)**	**SSPE2 (lb/yr)**	**BACT Triggered?**
NO_X	14.9	> 2.0	n/a	Yes
SO_X	3.8	> 2.0	n/a	Yes
PM_{10}	14.3	> 2.0	n/a	Yes
CO	75.5	> 2.0 and SSPE2 ≥ 200,000 lb/yr	161,858	No
VOC	10.2	> 2.0	n/a	Yes

As shown above, BACT is triggered for the NOx, PM10, VOC, and SOx emissions from the new auxiliary boiler.

N-4597-6-0: Fire-Pump Engine

New Emissions Unit BACT Applicability				
Pollutant	**Daily Emissions for Fire Pump Engine (lb/day)**	**BACT Threshold (lb/day)**	**SSPE2 (lb/yr)**	**BACT Triggered?**
NO_X	40.7	> 2.0	n/a	Yes
SO_X	0.1	> 2.0	n/a	No
PM_{10}	1.8	> 2.0	n/a	No
CO	36.4	> 2.0 and SSPE2 ≥ 200,000 lb/yr	161,858	No
VOC	2.4	> 2.0	n/a	Yes

As shown above, BACT is triggered for the NOx and VOC emissions from the new fire pump engine.

b. Relocation of emissions units – PE > 2 lb/day

As discussed previously in Section I, these engines are not being relocated from one stationary source to another as a result of this project. Therefore, BACT is not triggered for the relocation of emissions units with a PE > 2 lb/day.

c. Modification of emissions units – Adjusted Increase in Permitted Emissions (AIPE) > 2 lb/day

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

These units are not be relocated and are being treated as new since the class and category of source is changing. Therefore, BACT will not be triggered for the adjusted increase in permitted emissions.

N-4597-4-2: Emergency Generator Engine

The AIPE is used to determine if BACT is required for emissions units that are being modified. Since this emergency engine will be modified, the BACT requirements are based on the daily AIPE. Therefore, the AIPE needs to be calculated as follows:

Adjusted Potential to Emit (AIPE) Calculations:

AIPE = PE2 – HAPE where,

AIPE = Adjusted Increase in Permitted Emissions, lb/day.
PE2 = the emissions units post project Potential to Emit, lb/day.
HAPE = the emissions unit's Historically Adjusted Potential to Emit, lb/day.

Historically Adjusted Potential to Emit (HAPE) Calculations:

HAPE = PE1 x (EF2 ÷ EF1) where,

PE1 = The emissions unit's Potential to Emit prior to modification or relocation.
EF2 = The emissions unit's permitted emission factor for the pollutant after modification or relocation. If EF2 is greater than EF1 then EF2 ÷ EF1 shall be set to 1.
EF1 = The emissions unit's permitted emission factor for the pollutant before the modification or relocation.

AIPE (lb/day) = PE2 (lb/day) – [PE1 (lb/day) x (EF2 ÷ EF1)]

AIPE (lb/day) = PE2 (lb-NO_X/day) – [PE1 (lb-NO_X/day) x (EF2 ÷ EF1)]
AIPE lb/day = 116.9 lb-NO_X/day – [116.9 lb-NO_X/day x (4.69 g-NO_X/bhp-hr ÷ 4.69 g-NO_X/bhp-hr)]
AIPE = 0.0 lb-NO_X/day

AIPE (lb/day) = PE2 (lb-SO_X/day) – [PE1 (lb-SO_X/day) x (EF2 ÷ EF1)]
AIPE lb/day = 0.1 lb-SO_X/day – [0.1 lb-SO_X/day x (0.0051 g-SO_X/bhp-hr ÷ 0.0051g-SO_X/bhp-hr)]
AIPE = 0.0 lb-SO_X/day

AIPE (lb/day) = PE2 (lb-PM_{10}/day) – [PE1 (lb-PM_{10}/day) x (EF2 ÷ EF1)]
AIPE lb/day = 0.7 lb-PM_{10}/day – [0.7 lb-PM_{10}/day x (0.029 g-PM_{10}/bhp-hr ÷ 0.029 g-PM_{10}/bhp-hr)]
AIPE = 0.0 lb-PM_{10}/day

AIPE (lb/day) = PE2 (lb-CO/day) – [PE1 (lb-CO/day) x (EF2 ÷ EF1)]
AIPE lb/day = 3.0 lb-CO/day – [3.0 lb-CO/day x (0.12 g-CO/bhp-hr ÷ 0.12 g-CO/bhp-hr)]
AIPE = 0.0 lb-CO/day

AIPE (lb/day) = PE2 (lb-VOC/day) – [PE1 (lb-VOC/day) x (EF2 ÷ EF1)]
AIPE lb/day = 1.0 lb-VOC/day – [1.0 lb-VOC/day x (0.04 g-VOC/bhp-hr ÷ 0.04 g-VOC/bhp-hr)]
AIPE = 0.0 lb-VOC/day

Modified Emissions Unit BACT Applicability				
Pollutant	**AIPE for unit N-4597-4-2 (lb/day)**	**BACT Threshold (lb/day)**	**SSPE2 (lb/yr)**	**BACT Triggered?**
NO_X	0.0	> 2.0	n/a	No
SO_X	0.0	> 2.0	n/a	No
PM_{10}	0.0	> 2.0	n/a	No
CO	0.0	> 2.0 and SSPE2 ≥ 200,000 lb/yr	161,858	No
VOC	0.0	> 2.0	n/a	No

Therefore, BACT will not be triggered for the adjusted increase in permitted emissions.

N-4597-5-0: Auxiliary Boiler

This unit is a new unit; therefore, BACT cannot be triggered for a modification to the unit.

N-4597-6-0: Fire-Pump Engine

This unit is a new unit; therefore, BACT cannot be triggered for a modification to the unit.

d. Major Modification

As discussed previously in Section VII.C.7, this project does constitute a Major Modification for NOx emissions. Therefore, BACT for NOx will be triggered for all of the units.

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
- 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.

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

BACT Guideline 3.4.2, 1st Quarter 2009, applies to gas turbines rated at greater than 50 MW, with heat recovery. GWF Tracy is proposing to modify two 84.9 MW simple cycle gas turbines to add heat recovery equipment. Therefore, BACT Guideline 3.4.2 is applicable to each of the two CTG's and no further discussion is required (BACT Guideline 3.4.2 included in Attachment K).

N-4597-4-2: Emergency Generator Engine

BACT Guideline 3.1.3, 1st Quarter 2009, applies to emergency diesel IC engines rated at greater than or equal to 400 hp. GWF Tracy is proposing to modify this engine to reduce the annual hours of operation. Therefore, BACT Guideline 3.1.3 is applicable to this engine and no further discussion is required (BACT Guideline 3.1.3 included in Attachment L).

N-4597-5-0: Auxiliary Boiler

BACT Guideline 1.1.2, 1st Quarter 2009, applies to natural gas-fired boilers rated at greater than or equal to 20 MMBtu/hr. GWF Tracy is proposing to install a new 85 MMBtu/hr boiler. Therefore, BACT Guideline 1.1.2 is applicable to the boiler and no further discussion is required (BACT Guideline 1.1.2 included in Attachment M).

N-4597-6-0: Fire-Pump Engine

BACT Guideline 3.1.4, 1st Quarter 2009, applies to emergency diesel IC engines that power firewater pumps. GWF Tracy is proposing to install a new 288 bhp firewater pump. Therefore, BACT Guideline 3.1.4 is applicable to this engine and no further discussion is required (BACT Guideline 3.1.4 included in Attachment N).

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.

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

Pursuant to the Top-Down BACT Analysis in Attachment K, BACT is satisfied with the following:

NO_X: 2.0 ppmv dry @ 15% O_2 (1-hr average, excluding startup and shutdown), (Selective Catalytic Reduction, or equal) and operation with NH_3 injection at the earliest feasible catalyst temperature during startup and shutdown periods.

VOC: 2.0 ppmv @ 15% O_2 when the duct burner is firing and 1.5 ppmv O_2 when the duct burner is not firing.

PM_{10}: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel, or equal.

SO_X: PUC-regulated natural gas or non-PUC regulated gas with no more than 0.75 grains S/100 dscf, or equal.

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

- 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]
- Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]
- A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The owner/operator shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

- During all types of operation, including startup and shutdown periods, ammonia injection in to the SCR system shall occur once the minimum temperature at the catalyst face has been reached to ensure NO_X emission reductions can occur with a reasonable level of ammonia slip. The minimum catalyst face temperature shall be determined during the final design phase of this project and shall be submitted to the District at least 30 days prior to commencement of construction. [District Rule 2201]

- The SCR system shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the catalyst face. [District Rule 2201]

- The CTG shall only be fired on PUC-regulated natural gas with a sulfur content value not exceeding 0.66 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a daily basis and 0.25 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a 12-month rolling average basis. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

N-4597-4-2: Emergency Generator Engine

Pursuant to the Top-Down BACT Analysis in Attachment L, BACT is satisfied with the following:

NO_X: Certified NOx emissions of 6.9 g/bhp-hr or less

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

- Emissions from this IC engine shall not exceed any of the following limits: 4.69 g-NOx/bhp-hr, 0.12 g-CO/bhp-hr, or 0.04 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

N-4597-5-0: Auxiliary Boiler

Pursuant to the Top-Down BACT Analysis in Attachment M, BACT is satisfied with the following:

NO_X: 9.0 ppmvd @ 3% O_2 (0.0108 lb/MMBtu-hr) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal

VOC: Natural gas fuel with LPG backup

PM10: Natural gas fuel with LPG backup

SOx: PUC-regulated natural gas or non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal.

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

- Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) – 6.0 ppmvd @ 3% O2 or 0.0073 lb/MMBtu; VOC (as methane) – 0.005 lb/MMBtu; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.007 lb/MMBtu; or SOx (as SO2) - 0.0019 lb/MMBtu. [District Rules 2201, 4305, 4306, 4320, and 4351]

- The boiler shall only be fired on PUC-regulated natural gas with a sulfur content value not exceeding 0.66 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a daily basis and 0.25 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a 12-month rolling average basis. [District Rule 2201]

N-4597-6-0: Fire-Pump Engine

Pursuant to the Top-Down BACT Analysis in Attachment N, BACT is satisfied with the following:

NO_x: Certified NOx emissions of 6.9 g/bhp-hr or less

VOC: Positive Crankcase Ventilation (unless it voids the Underwriters Laboratory Certification)

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

- Emissions from this IC engine shall not exceed any of the following limits: 2.67 g-NOx/bhp-hr, 2.39 g-CO/bhp-hr, or 0.16 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115 and 40 CFR 60.4205(c)]

- This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]

B. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_X and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_X and 29,200 lbs/year for PM_{10}. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_X, VOC, and PM_{10} 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)	180,572	161,858	31,997	66,884	14,406
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 Sections 4.7.2 and 4.7.3, the quantity of offsets, in pounds per year, is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = ([SSPE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,

SSPE2 = Post Project Facility Potential to Emit, (lb/year)
BE = Baseline Emissions (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

As stated in the calculations section earlier, BE is equivalent to PE1 for NOx, VOC, and PM10 emissions for all of the units in this project. Since the IC engines are exempt from offsets per District Rule 2201 Section 4.6.2, emissions from the IC engines are not included in the determination of the quantity of offsets required.

The quantity of offsets required for each unit is shown in the following tables.

Offset Quantity Determination (N-4597-1-5)			
	NO_X (lb/year)	VOC (lb/year)	PM_{10} (lb/year)
PE2	88,881	15,145	32,250
PE1	153,460	13,356	26,667
Difference	-64,579	1,789	5,583

Offset Quantity Determination (N-4597-2-5)			
	NO_X (lb/year)	VOC (lb/year)	PM_{10} (lb/year)
PE2	88,881	15,145	32,250
PE1	153,460	13,356	26,667
Difference	-64,579	1,789	5,583

Offset Quantity Determination (N-4597-5-0)			
	NO_X (lb/year)	VOC (lb/year)	PM_{10} (lb/year)
PE2	2,482	1,700	2,380
PE1	0	0	0
Difference	2,482	1,700	2,380

The above tables show the quantities of offsets that would be required for each unit if offsets were triggered on a unit by unit basis; however, District Rule 2201 Section 4.5.1 states that offsets are required for the "net emission increases resulting from a project". Since offsets are triggered for net emissions increases for a project rather than on a unit by unit basis, decreases in emissions from one unit within a project can be used to counteract increases in emissions from another unit within the project, such that the net emissions increase is equal to or less than zero. This is commonly referred to as "netting". The following table shows quantity of offsets required for the project, based on the net emission increases from the project:

Offset Quantity Determination			
Permit Unit	Increase in NO_X (lb/year)	Increase in VOC (lb/year)	Increase in PM_{10} (lb/year)
N-4597-1-5	-64,579	1,789	5,583
N-4597-2-5	-64,579	1,789	5,583
N-4597-5-0	2,482	1,700	2,380
Total Net Emissions Increase	-126,676	5,278	13,546

As shown in the previous table, there is a net increase in VOC and PM10 emissions; while there is a net decrease in NOx emissions from the project.

The applicant has proposed to use the net decrease in NOx emissions to counteract the increase in VOC and PM10 emissions. For the purposes of this document, this action will be referred to as "interpollutant netting". District Rule 2201 recognizes that NOx is a precursor for Ozone and PM10. The District has evaluated the applicant's interpollutant netting proposal and determined that this proposal is consistent with District Rule 2201 requirements.

Interpollutant offset ratios for trades between NOx and VOC, and NOx and PM10 will be used to determine the quantity of NOx required to counteract the VOC and PM10 emission increases in the project. Interpollutant ratios of 1:1 for NOx:VOC and 2.629:1 for NOx: PM10 will be applied. Please refer to the interpollutant offset analysis in Attachment O of this evaluation for an explanation of the derivation of the NOx:PM10 interpollutant offset ratio. The NOx:VOC interpollutant ratio of 1:1 was derived from the modeling used for the District's 8-hour Ozone Plan.

The increase in VOC emissions from the project is 5,278 lb/year. The quantity of NOx reductions required to counteract the VOC emissions increase from the project is:

NOx for VOC = 5,278 lb-VOC/year x 1 lb-NOx/1 lb-VOC = 5,278 lb-NOx/year

The increase in PM10 emissions is 13,546 lb/year. The quantity of NOx reductions required to counteract offset the PM10 increase from the project is:

NOx for PM10 = 13,546 lb-PM10/year x 2.629 lb-NOx/lb-PM10 = 35,612 lb-NOx/year

The total quantity of NOx reductions needed to counteract offset the increases in VOC and PM10 from the project is:

Total NOx Required = 5,278 lb/year + 35,612 lb/year = 40,890 lb-NOx/year

Based on the previous table, the project will decrease NOx emissions by 126,676 lb/year. 40,890 lb/year of this decrease will be applied toward the VOC and PM10 emission increases, such that the quantity of offsets required for PM10 and VOC from the project is equal to zero. The applicant could bank the remaining NOx emission reductions and receive Emission Reduction Credits for any emission reductions that are real and surplus (if any) that may have been created by this project; however, the applicant has stated that they will not apply to bank any Emission Reduction Credits for this project.

While the above analysis demonstrates that District offset requirements are satisfied, the District is required to conduct an annual analysis to demonstrate equivalency between the District offset requirements and Federal offset requirements. To properly address the equivalency determination and to ensure that federal offsets are provided for this project, the District will debit the Districts offset equivalency tracking program by the appropriate VOC and PM10 quantities. Pursuant to EPA Region 9, this will satisfy the federal offset requirements for this project.

C. 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 above, GWF Tracy is currently a Major Source for NOx emissions and is not becoming a new Major Source for any pollutants. Therefore, public noticing is not required for this project for new Major Source purposes.

b. Major Modification

As demonstrated in Section VII.C.7 above, this project constitutes a Major Modification; therefore, public noticing for Major Modification purposes is 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 the new boiler (N-4597-5-0) and for the new firepump engine (N-4597-6-0) 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)
N-4597-5-0	14.9	75.5	10.2	14.3	3.8	0
N-4597-6-0	40.7	36.4	2.4	1.8	0.1	0
Threshold (lb/day)	100	100	100	100	100	100
Notification Required?	No	No	No	No	No	No

According to the table above, neither of the new units emits any pollutant at a rate of 100 pounds per day or greater. Therefore, public noticing will not 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	307,894	180,572	20,000 lb/year	No
CO	143,265	161,858	200,000 lb/year	No
VOC	26,720	31,997	20,000 lb/year	No
PM_{10}	53,340	66,884	29,200 lb/year	No
SO_X	11,201	14,406	54,750 lb/year	No

As detailed above, offset thresholds for CO and SOx will not be surpassed for any of the pollutants with this project. Additionally, the NOx, VOC, and PM10 pre-project emissions are already greater than the offset thresholds; therefore, the thresholds cannot be surpassed in this project. Public noticing is not 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	180,572	307,894	< 0	20,000 lb/year	No
CO	161,858	143,265	18,593	20,000 lb/year	No
VOC	31,997	26,720	5,277	20,000 lb/year	No
PM_{10}	66,884	53,340	13,544	20,000 lb/year	No
SO_X	14,406	11,201	3,205	20,000 lb/year	No
NH_3	118,930	211,040	< 0	20,000 lb/year	No

As demonstrated above, the SSIPE is not greater than 20,000 lb/year for any pollutant; therefore public noticing for SSIPE purposes is not 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 for major modification purposes, the District shall public notice this project according to the requirements of Section 5.5.

D. Daily Emission Limits:

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

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

For the turbines, the DELs for NO_X, CO, VOC, PM_{10}, SO_X, and NH_3 will consist of lb/day limits and/or emission factors. The following conditions will ensure continued compliance with the DEL requirements of this rule:

- Emission rates from this CTG without the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 8.10 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.90 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 1.13 lb/hr and 1.5 ppmvd @ 15% O_2; PM_{10} – 4.40 lb/hr; or SO_X (as SO_2) – 2.03 lb/hr. NO_X (as NO_2) emission rates and concentration limits are based on one hour rolling averages. All other emission rates and concentrations are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- Emission rates from this CTG with the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 10.30 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 6.00 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 3.22 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 5.80 lb/hr; or SO_X (as SO_2) – 2.63 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- During start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 390.5 lb/event; CO – 562.5 lb/event; VOC (as methane) – 10.5 lb/event; PM_{10} – 11.0 lb/event; or SO_X (as SO_2) – 4.1 lb/event. [District Rules 2201 and 4703]

- During shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) –104.0 lb/event; CO – 148.0 lb/event; VOC (as methane) – 2.6 lb/event; PM_{10} – 3.0 lb/event; or SO_X (as SO_2) – 1.1 lb/event. [District Rules 2201 and 4703]

- The ammonia (NH_3) emissions shall not exceed 5 ppmvd @ 15% O_2 or 9.40 lb/hr over a 24 hour rolling average. [District Rules 2201 and 4102]

- Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the owner/operator shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the owner/operator may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the owner/operator shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

- Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 814.9 lb/day; CO – 1071.6; VOC – 78.6 lb/day; PM_{10} – 132.0 lb/day; or SO_X (as SO_2) – 58.7 lb/day. [District Rule 2201]

- The CTG shall only be fired on PUC-regulated natural gas with a sulfur content value not exceeding 0.66 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a daily basis and 0.25 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a 12-month rolling average basis. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

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 consecutive month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 88,881 lb/year; CO – 74,598 lb/year; VOC – 15,145 lb/year; PM_{10} – 32,250 lb/year; or SO_X (as SO_2) – 7,084 lb/year. Compliance with the annual NOx and CO emission limits shall be demonstrated using CEM data and compliance with the annual VOC, PM10, and SOx emission limits shall be demonstrated using the most recent source test results. [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 rolling 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]

N-4597-4-2: Emergency Generator Engine

For the emergency generator engine, the DELs will be enforced by the following conditions

- Emissions from this IC engine shall not exceed any of the following limits: 4.69 g-NOx/bhp-hr, 0.12 g-CO/bhp-hr, or 0.04 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201, 4102, and 4801 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.029 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]

N-4597-5-0: Auxiliary 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) – 6.0 ppmvd @ 3% O2 or 0.0073 lb/MMBtu; VOC (as methane) – 0.005 lb/MMBtu; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.007 lb/MMBtu; or SOx (as SO2) - 0.0019 lb/MMBtu. [District Rules 2201, 4305, 4306, 4320, and 4351]

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

- The boiler shall operate a maximum of 4,000 hours per calendar year. [District Rule 2201]

- The boiler shall only be fired on PUC-regulated natural gas with a sulfur content value not exceeding 0.66 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a daily basis and 0.25 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a 12-month rolling average basis. [District Rule 2201]

N-4597-6-0: Fire-Pump Engine

For the fire pump engine, the DELs will be enforced by the following conditions:

- Emissions from this IC engine shall not exceed any of the following limits: 2.67 g-NOx/bhp-hr, 2.39 g-CO/bhp-hr, or 0.16 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115 and 40 CFR 60.4205(c)]

- 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 and 40 CFR 60.4207]

- Emissions from this IC engine shall not exceed 0.12 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 and 40 CFR 60.4205(c)]

E. 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. GWF Tracy has submitted a compliance certification satisfying this requirement. See Attachment P.

F. Alternative Siting Analysis

Section 4.15.1 of this rule requires sources for which an analysis of alternative sites, sizes, and production processes is required under Section 173 of the Federal Clean Air Act, the applicant shall prepare an analysis functionally equivalent to the requirements of Division 13, Section 21000 et. seq. of the Public Resources Code. The alternative analysis has been provided as part of the CEQA analysis performed by the California Energy Commission. Therefore, this requirement has been satisfied.

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 Q of this document for the AQIA summary sheet.

The proposed location is in an attainment area for NO_X, CO, SOx, and PM10. As shown by the table below, the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, SOx, or PM10.

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
PM_{10}	N/A	N/A	N/A	Pass	Pass

H. Compliance Assurance:

1. Source Testing

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

District Rule 4703, Section 6.3.1 states that the owner or operator of any stationary gas turbine shall perform source testing for NO_X and CO emissions 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, VOC, CO, PM_{10}, and ammonia slip will be required within 60 days of initial operation and at least once every 12 months thereafter.

Therefore, the following source testing requirements will ensure continued compliance with the requirements of this rule:

- Source testing to measure the steady state NOx, CO, VOC, and NH3 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, 2201 and 4703 and 40 CFR 60.4400]

- Source testing to measure the PM10 emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081, 2201 and 40 CFR 60.4400]

- Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703]

In addition, source testing of NO_X and CO startup and shutdown 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 CEM's accurately measure startup emissions.

- Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (N-4597-1 or N-4597-2) within 60 days after the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NO_X and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081 and 2201]

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.

<u>N-4597-4-2: Emergency Generator Engine</u>

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

<u>N-4597-5-0: Auxiliary Boiler</u>

This unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3, and District Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr.* Source testing requirements, in accordance with District Rules 4305, 4306 and 4320, will be discussed in Section VIII, *District Rules 4305, 4306, and 4320*, of this evaluation.

<u>N-4597-6-0: Fire-Pump Engine</u>

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

2. Monitoring

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

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 following conditions will be included on the permits to ensure compliance:

- Testing to demonstrate compliance with the short-term (daily) fuel sulfur content limit shall be conducted monthly. If a monthly test indicates that a violation of the daily fuel sulfur content limit has occurred then weekly testing shall commence and continue until eight consecutive tests show compliance. Once compliance with the daily fuel sulfur content is demonstrated on eight consecutive weekly tests, testing may return to the monthly schedule. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. [District Rule 2201 an 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

- Compliance with the rolling 12-month average fuel sulfur content limit shall be demonstrated monthly. The 12-month rolling average fuel sulfur content shall be calculated as follows: 12-month rolling average fuel sulfur content = Sum of the monthly average fuel sulfur contents for the previous 12 months ÷ total number of months the unit has operated in during the previous 12 months. The monthly average fuel sulfur content is the average fuel sulfur content of all tests conducted in a given month. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. Owner/operator shall keep a monthly record of the rolling 12-month average fuel sulfur content. [District Rules 1081 and 2201]

- 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)]

N-4597-4-2: Emergency Generator Engine

No monitoring is required to demonstrate compliance with Rule 2201.

N-4597-5-0: Auxiliary Boiler

This unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3, and District Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr.* Monitoring requirements, in accordance with District Rules 4305, 4306, and 4320 will be discussed in Section VIII, *District Rules 4305, 4306, and 4320*, of this evaluation.

Additionally, the following conditions will enforce the natural gas fuel sulfur content limits.

- Testing to demonstrate compliance with the short-term (daily) fuel sulfur content limit shall be conducted monthly. If a monthly test indicates that a violation of the daily fuel sulfur content limit has occurred then weekly testing shall commence and continue until eight consecutive tests show compliance. Once compliance with the daily fuel sulfur content is demonstrated on eight consecutive weekly tests, testing may return to the monthly schedule. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. [District Rule 2201]

- Compliance with the rolling 12-month average fuel sulfur content limit shall be demonstrated monthly. The 12-month rolling average fuel sulfur content shall be calculated as follows: 12-month rolling average fuel sulfur content = Sum of the monthly average fuel sulfur contents for the previous 12 months ÷ total number of months the unit has operated in during the previous 12 months. The monthly average fuel sulfur content is the average fuel sulfur content of all tests conducted in a given month. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. Owner/operator shall keep a monthly record of the rolling 12-month average fuel sulfur content. [District Rules 1081 and 2201]

- 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. [District Rule 2201]

N-4597-6-0: Fire-Pump Engine

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

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.

N-4597-4-2: Emergency Generator Engine

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*, this IC engine is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

N-4597-5-0: Auxiliary Boiler

This unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3, and District Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr.* Recordkeeping requirements, in accordance with District Rules 4305, 4306, and 4320 will be discussed in Section VIII, *District Rules 4305, 4306, and 4320*, of this evaluation.

The following permit condition will be listed on the 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, 4306, and 4320]

Additionally, this unit is limited to 4,000 hours/year of operation. Therefore, the following condition will be included on the permit to ensure compliance:

- Owner/operator shall keep a record of the cumulative annual quantity of hours operated for this unit. The record shall be updated at least monthly. [District Rule 2201]

N-4597-6-0: Fire-Pump Engine

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*, this IC engine is 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

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

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.

N-4597-4-2: Emergency Generator Engine

No reporting is required to ensure compliance with Rule 2201.

N-4597-5-0: Auxiliary Boiler

No reporting is required to ensure compliance with Rule 2201.

N-4597-6-0: Fire-Pump Engine

No reporting is required to ensure compliance with Rule 2201.

Rule 2520 Federally Mandated Operating Permits

This facility is subject to this Rule, and has received their Title V Operating Permit. Section 3.29 defines a significant permit modification as a "permit amendment that does not qualify as a minor permit modification or administrative amendment." Any project that is a Major Modification per District Rule 2201 cannot be processed as a minor modification to the Title V permit. Since this project triggers a District Major Modification, this project constitutes a Significant Modification to the Title V Permit.

The facility has applied for a Certificate of Conformity (COC), in accordance with the requirements of 40 CFR 70.6(c), and 70.8. A 45-day EPA comment period will be satisfied prior to the issuance of the Authority to Construct permits. GWF Tracy will apply to modify their Title V permit with an administrative amendment prior to operating with the proposed modifications. Therefore, compliance with this rule is expected. The following conditions will be included on each permit:

- This Determination of Compliance serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]

- Prior to operating with modifications authorized by this Determination of Compliance, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

Rule 2540 Acid Rain Program

The proposed CTG's are subject to the acid rain program as phase II units. GWF Tracy already has the Acid Rain requirements listed on permits N-4597-1-4 and N-4597-2-4. The below acid rain requirements will be retained and placed on permits N-4597-1-5 and N-4597-2-5:

- The owners and operators of each affected source and each affected unit at the source shall: (i) Operate the unit in compliance with a complete Acid Rain permit application or a superceding Acid Rain permit issued by the permitting authority; and (ii) have an Acid Rain permit. [40 CFR 72]

- The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75]

- The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75]

- The owners and operators of each source and each affected unit at the source shall: (i) hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73]

- Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77]

- An affected unit shall be subject to the sulfur dioxide requirements starting on the later of January 1, 2000, or the deadline for monitoring certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3) that is not a substitution or compensating unit. [40 CFR 72, 40 CFR 75]

- Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72]

- An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73]

- An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72]

- An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72]

- The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides. [40 CFR 72]

- The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77]

- The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77]

- The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72]

- The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 72, 40 CFR 75]

- The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75]

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 Non-criteria pollutants/HAPs.

Non-criteria 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.(5)

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)). Any pollutant that may be emitted from the project and is on the federal New Source Review List and the federal Clean Air Act list has been evaluated.

The applicant has supplied the following data:

Hazardous Air Pollutant Emissions GWF Tracy – GE Frame 7EA Turbines				
Compound	Emission Factor (lb/MMscf)*	lb/hr (per turbine)**	lb/yr (per turbine)***	lb/yr 2 turbines
Acetaldehyde	0.137	0.19	1,401	2,802
Acrolein	0.0189	0.03	193	387
Benzene	0.0133	0.02	136	272
1,3-Butadiene	0.000127	0.00	1	3
Ethylbenzene	0.0179	0.02	183	366
Formaldehyde	0.917	1.27	9,378	18,756
Hexane	0.259	0.36	2,649	5,298
Napthalene	0.00166	0.00	17	34
PAHs	0.000014	0.00	0	0
Propylene	0.771	1.07	7,885	15,770
Propylene Oxide	0.0478	0.07	489	978
toluene	0.071	0.10	726	1,452
Xylene	0.0261	0.04	267	534
Total HAPS	-	**3.16**	**23,326**	**46,652**

* Obtained from the California Air Toxic Emission Factors (CATEF) database.
** Based on an hourly maximum natural gas usage rate of 1.387 MMCF/hr.
***Based on an annual maximum natural gas usage rate of 10,227 MMCF/yr.

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

Hazardous Air Pollutant Emissions GWF Tracy – 471 HP Emergency Engine			
Compound	**Emissions Factor (lb/1000 gal)***	**lb/hr****	**lb/yr*****
Benzene	0.1863	0.0042	2
Formaldehyde	1.7261	0.0385	19
PAHs	0.0559	0.0012	1
Naphthalene	0.0197	0.0004	0
Acetaldehyde	0.7833	0.0175	9
Acrolein	0.0339	0.0008	0
1,3 Butadiene	0.2174	0.0048	2
Chlorobenzene	0.002	0.0000	0
Dioxins	ND	ND	ND
Furans	ND	ND	ND
Propylene	0.467	0.0104	5
Hexane	0.0269	0.0006	0
Toluene	0.1054	0.0024	1
Xylene	0.0424	0.0009	0
Ethyl Benzene	0.0109	0.0002	0
Hydrogen Chloride	0.1863	0.0042	2
Arsenic	0.0016	0.0000	0
Beryllium	ND	ND	ND
Cadmium	0.0015	0.0000	0
Total Chromium	0.0006	0.0000	0
Hexavalent Chromium	0.0001	0.0000	0
Copper	0.0041	0.0001	0
Lead	0.0083	0.0002	0
Manganese	0.0031	0.0001	0
Mercury	0.002	0.0000	0
Nickel	0.039	0.0009	0
Selenium	0.0022	0.0000	0
Zinc	0.0224	0.0005	0
Total		**0.0880**	**41**

* Emission Factors from Ventura County APCD AB-2588 Combustion Emission Factors, dated May 17, 2001
** Based on a fuel usage rate of 22.3 gal/hr
*** Based on a fuel usage rate of 11,150 gal/yr (based on 500 hr/year worst-case scenario for emergency and non-emergency use, per EPA)

Hazardous Air Pollutant Emissions GWF Tracy – Auxiliary Boiler			
Compound	**Emissions Factor (lb/MMScf)**	**lb/hr*****	**lb/yr*****
Benzene*	0.00431	0.0004	2
Formaldehyde*	0.0221	0.0021	8
Acetaldehyde*	0.00887	0.0008	3
Toluene**	0.0034	0.0003	1
Copper**	0.00085	0.0001	0
Nickel**	0.0021	0.0002	1
Total	-	**0.0039**	**16**

* Emissions Factors from CATEF Emission Factors for Natural Gas Fired Boiler
**Emissions Factors from AP-42 Tables 1.4-3 and 1.4-4, revised 7/98
*** Based on an hourly fuel usage rate of 0.0938 MMScf/hr and annual operating schedule of 4000 hr/year

Hazardous Air Pollutant Emissions GWF Tracy – 288 HP Emergency Engine			
Compound	Emissions Factor (lb/1000 gal)*	lb/hr**	lb/yr***
Benzene	0.1863	0.0027	1
Formaldehyde	1.7261	0.0250	13
PAHs	0.0559	0.0008	0
Naphthalene	0.0197	0.0003	0
Acetaldehyde	0.7833	0.0114	6
Acrolein	0.0339	0.0005	0
1,3 Butadiene	0.2174	0.0032	2
Chlorobenzene	0.002	0.0000	0
Dioxins	ND	ND	ND
Furans	ND	ND	ND
Propylene	0.467	0.0068	3
Hexane	0.0269	0.0004	0
Toluene	0.1054	0.0015	1
Xylene	0.0424	0.0006	0
Ethyl Benzene	0.0109	0.0002	0
Hyrogen Chloride	0.1863	0.0027	1
Arsenic	0.0016	0.0000	0
Beryllium	ND	ND	ND
Cadmium	0.0015	0.0000	0
Total Chromium	0.0006	0.0000	0
Hexavalent Chromium	0.0001	0.0000	0
Copper	0.0041	0.0001	0
Lead	0.0083	0.0001	0
Mangancese	0.0031	0.0000	0
Mercury	0.002	0.0000	0
Nickel	0.039	0.0006	0
Selenium	0.0022	0.0000	0
Zinc	0.0224	0.0003	0
Total		**0.0573**	**27**

* Emission Factors from Ventura County APCD AB-2588 Combustion Emission Factors, dated May 17, 2001
** Based on a fuel usage rate of 14.5 gal/hr
*** Based on a fuel usage rate of 7,250 gal/yr (based on 500 hr/year worst-case scenario for emergency and non-emergency use, per EPA)

Hazardous Air Pollutant Emissions GWF Tracy – Facility	
Compound	lb/yr
Acetaldehyde	2,820
Acrolein	387
Arsenic	~0
Benzene	277
Beryllium	~0
1,3 Butadiene	7
Cadmium	~0
Chlorobenzene	~0
Total Chromium	~0
Copper	~0
Dioxins	ND
Ethyl Benzene	366
Formaldehyde	18,796
Furans	ND
Hexane	5,298
Hexavalent Chromium	~0
Hydrogen Chloride	3
Lead	~0
Manganese	~0
Mercury	~0
Napthalene	34
Nickel	1
PAHs	1
Propylene	15,778
Propylene Oxide	978
Selenium	~0
Toluene	1,455
Xylene	534
Zinc	~0
Total	**46,735**

Therefore, as emissions of each individual HAP are below 10 tons (20,000 lb) per year and total HAP emissions are below 25 tons (50,000 lb) per year, GWF Tracy will not be a major air toxics source and the provisions of this rule do not apply. The following condition will be included on the permits for the turbines to ensure that HAP emissions remain below the Major HAP Source trigger threshold:

- The combined natural gas fuel usage for turbines N-4597-1 and N-4597-2 shall not exceed 20,454 MMScf/year. [District Rule 2520]

Rule 4001 New Source Performance Standards

40 CFR 60 – Subpart Db

NSPS Subpart Db applies to steam generating units that are constructed, reconstructed, or modified after June 19, 1984 and that have a heat capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (100 MMBtu/hr). While each turbine unit is equipped with a 324 MMBtu/hr duct burner, 60.40b(i) states that heat recovery steam generators that are associated with a combined cycle turbine and that meet the applicability requirements of Subpart GG or Subpart KKKK are not subject to this subpart. The proposed units meet the applicability requirements of Subpart KKKK; therefore, Subpart Db requirements are not applicable.

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}. The 85 MMBtu/hr boiler is subject to Subpart Dc requirements. The remainder of the Subpart Dc section applies only to the 85 MMBtu/hr boiler.

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)]

- Owner/operator 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 4320 requires that records be kept for five years.

<u>40 CFR 60 – Subpart GG</u>

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. This project is a modification of the existing turbines. GWF Tracy has indicated that the installation and construction of the modified plant will commence in Fall 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. GWF Tracy has indicated that the modification of the proposed equipment will commence in Fall 2011. Therefore, these turbines also meet the applicability requirements of Subpart KKKK.

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

This subpart is applicable to owners and operators of stationary compression ignited internal combustion engines that commence construction (is ordered by the owner or operator) 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.
3) Modified or reconstructed after July 11, 2005.

N-4597-4-2: Emergency Generator Engine

This engine was installed in September, 2003 and is not being modified or reconstructed since the original installation of the engine. Thus, Subpart IIII requirements are not applicable to this engine.

N-4597-6-0: Fire-Pump Engine

This engine is a newly proposed engine and is subject to Subpart IIII requirements.

Pursuant to Section 60.4205(c), fire pumps with a displacement less than 30 liters/cylinder must comply with the emission standards listed in Table 1 of Subpart IIII. For a 2009 or later 288 BHP engine, the emission standards listed in Table 1 are equivalent to the Tier 3 non-road emission standards. The applicant is proposing a Tier 3 rated engine. The following conditions will be included on the permit:

- Emissions from this IC engine shall not exceed any of the following limits: 2.67 g-NOx/bhp-hr, 2.39 g-CO/bhp-hr, or 0.16 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423, 13 CCR 2423 and 17 CCR 93115, and 40 CFR 60.4205(c)]

- Emissions from this IC engine shall not exceed 0.12 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102, 13 CCR 2423 and 17 CCR 93115, and 40 CFR 60.4205(c)]

Section 60.4207 requires the use of fuel that meets the following requirements:

1. By October 1, 2007, the fuel must have a sulfur content less than or equal to 500 ppm and a minimum centane index of 40 or a maximum aromatic content of 35 percent by volume.
2. By October 1, 2010, the fuel must have a sulfur content less than or equal to 15 ppm and a minimum centane index of 40 or a maximum aromatic content of 35 percent by volume.

CARB certified diesel fuel has a sulfur content of 15 ppm or less and a maximum aromatic content of 20 percent by volume. Therefore, use of CARB certified diesel fuel satisfies this requirement. The following condition will be included on the permit:

- Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201, 4102, and 4801 and 17 CCR 93115 and 40 CFR 60.4207]

Section 60.4209(a) requires the installation of a non-resettable elapsed time hour meter. The following condition will be included on the permit:

- The engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702, 17 CCR 93115, and 40 CFR 60.4209(a)]

Section 60.4211(e) limits operation of the engine, for maintenance and testing purposes, to 100 hours/year. The following condition will be included on the permit:

- 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", 2002 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702, 17 CCR 93115, and 40 CFR 60.4211(e)]

Section 60.4211(a) requires the owner/operator to operate and maintain the engine and any installed control devices according to manufacturer's instructions. The following condition will be included on the permit:

- This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [40 CFR 60.4211(a)]

Therefore, the 288 bhp emergency fire pump engine is expected to comply with the requirements of Subpart IIII.

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 1,091 MMBtu/hr (HHV), 983 MMBtu/hr (LHV), at 15 degrees F and will be modified after February 18, 2005. Therefore, this subpart applies to the proposed 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. Table 1 states that new turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr must meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 150 ng/J of useful output (1.2 lb/MWh).

GWF Tracy's turbines have a peak heat input greater than 850 MMBtu/hr and GWF Tracy 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 CTG without the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 8.10 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.90 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 1.13 lb/hr and 1.5 ppmvd @ 15% O_2; PM_{10} – 4.40 lb/hr; or SO_X (as SO_2) – 2.03 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- Emission rates from this CTG with the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 10.30 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 6.00 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 3.22 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 5.80 lb/hr; or SO_X (as SO_2) – 2.63 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

Section 60.4330 - Standards for Sulfur Dioxide:

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

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain 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.

GWF Tracy is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 0.66 grain/100 scf (0.0019 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 only be fired on PUC-regulated natural gas with a sulfur content value not exceeding 0.66 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a daily basis and 0.25 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a 12-month rolling average basis. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

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

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

The proposed turbines utilize dry-low NOx burners to reduce NOx emissions; therefore, this section is not applicable to the proposed turbines.

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

GWF Tracy 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 monitor emissions during all types of operation, including 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 flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flow meters 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.

GWF Tracy will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, GWF Tracy 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 Specifications 2, 3, and 4, and/or 40 CFR 75 Appendix A, 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)]

- The owner/operator shall perform a relative accuracy test audit (RATA) for NOx, CO, and O2 as specified by 40 CFR Part 60, Appendix F, 5.11, or 40 CFR Part 75 Appendix B, at least once every 4 calendar quarters. The owner/operator shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures in 40 CFR Part 60 Appendix F. If the RATA test is conducted as specified in 40 CFR Part 75 Appendix B, the RATA shall be conducted on a lb/MMBtu basis. [District Rule 1080 and 40 CFR 60.4345]

- The owner/operator shall develop and keep onsite a quality assurance plan for all the continuous monitoring equipment described in 40 CFR 60.4345(a), (c), and (d). [40 CFR 60.4345(e)]

Section 60.4350 – CEMS Data and Excess NO_X Emissions:

Section 60.4350 states that for purposes of identifying excess emissions:

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

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average 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.

(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).

GWF Tracy is proposing to monitor the NO_X emissions rates from these 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 averaged over a one hour period for NOx emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of 40 CFR 60.13. [District Rule 1080, 40 CFR 60.13 and 40 CFR 60.4350(a)]

- For the purpose of determining excess NOx emissions, for each unit operating hour in which a valid hourly average is obtained, the data acquisition system and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 of 40 CFR 60 Appendix A. For any hour in which the hourly O2 concentration exceeds 19.0 percent O2, a diluent cap value of 19 percent O2 may be used in the emission calculations. [40 CFR 60.4350(b)]

Section 60.4355 – Parameter Monitoring Plan:

This section sets fourth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, GWF Tracy 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.

GWF Tracy is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 0.66 grains/100 scf.

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.

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

- Testing to demonstrate compliance with the short-term (daily) fuel sulfur content limit shall be conducted monthly. If a monthly test indicates that a violation of the daily fuel sulfur content limit has occurred then weekly testing shall commence and continue until eight consecutive tests show compliance. Once compliance with the daily fuel sulfur content is demonstrated on eight consecutive weekly tests, testing may return to the monthly schedule. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. [District Rule 2201 an 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

- Compliance with the rolling 12-month average fuel sulfur content limit shall be demonstrated monthly. The 12-month rolling average fuel sulfur content shall be calculated as follows: 12-month rolling average fuel sulfur content = Sum of the monthly average fuel sulfur contents for the previous 12 months ÷ total number of months the unit has operated in during the previous 12 months. The monthly average fuel sulfur content is the average fuel sulfur content of all tests conducted in a given month. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. Owner/operator shall keep a monthly record of the rolling 12-month average fuel sulfur content. [District Rules 1081 and 2201]

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6628, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

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, GWF Tracy 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 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. 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. GWF Tracy 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 NOx emissions shall be defined as any 30 day operating period in which the 30 day rolling average NOx concentration exceeds an applicable emissions limit. A 30 day rolling average NOx emission rate is the arithmetic average of all hourly NOx emission data in ppm measured by the continuous 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 NOx emission rates for the preceding 30 unit operating days if a valid NOx emission rate is obtained for at least 75 percent of all operating hours. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx or O2 (or both). [40 CFR 60.4350(h) and 40 CFR 60.4380(b)(1)]

<u>Section 60.4385 – Excess SO_X Emissions:</u>

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.

GWF Tracy 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. The following condition will be included on the turbine permits:

- Excess SOx emissions is each unit operating hour including the period beginning on the date and hour of any sample for which the fuel sulfur content exceeds the applicable limits listed in the permit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. Monitoring downtime for SOx begins when a sample is not taken by its due date. A period of monitor downtime for SOx also begins on the date and hour of a required sample, if invalid results are obtained. A period of SOx monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)]

<u>Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:</u>

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. GWF Tracy 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]

<u>Section 60.4400 – NO_X Performance Testing:</u>

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

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

GWF Tracy will be required to source test the exhaust of these turbines within 60 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 measure the steady state NOx, CO, VOC, and NH3 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, 2201 and 4703 and 40 CFR 60.4400]

- Source testing to measure the PM10 emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081, 2201 and 40 CFR 60.4400]

- The following test methods shall be used: NO_X - EPA Method 7E, 20, or ARB Method 100 and EPA Method 19 (Acid Rain Program); CO - EPA Method 10 or 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 and 202 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20, or ARB Method 100. NOx testing shall also be conducted in accordance with the requirements of 40 CFR 60.4400(a)(2), (3), and (b). 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) and 40 CFR 60.4400(a)(2), (3), and (b)]

<u>Section 60.4405 – Initial CEMS Relative Accuracy Testing:</u>

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). GWF Tracy 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.

<u>Section 60.4410 – Parameter Monitoring Ranges:</u>

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, GWF Tracy 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).

GWF Tracy is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines. 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. GWF Tracy is not proposing to measure the SO_2 in the exhaust stream of these 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 YYYY

Applicability

This subpart is applicable to turbines that are located at major sources of HAP emissions. This facility is not a major source of HAP emissions; therefore, this subpart is not applicable.

40 CFR 63– Subpart ZZZZ

Applicability

This subpart is applicable to stationary internal combustion engines that are located at major or area sources of HAP emissions, except if the stationary IC engine is being tested at a stationary IC engine test cell/stand. Per this subpart, an area source of HAP emissions is a source that is not a major source of HAP emissions. This facility is not a major source of HAP emissions; therefore, this source is an area source of HAP emissions and this subpart is applicable.

Requirements

Pursuant to 40 CFR §63.6590(b)(3), existing compression ignited stationary IC engines do not have to meet the requirments of Subpart ZZZZ and Subpart A of Part 63. An existing engine is an engine that is installed prior to June 12, 2006 and that has not been modified or reconstructed since that date. The existing engine powering the emergency generator was installed prior to June 12, 2006 and has not been modified or reconstructed. Thus, Subpart ZZZZ requirements do not apply to existing engine at GWF Tracy.

Pursuant to 40 CFR §63.6590(c), new stationary IC engines located at an area source must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR Part 60 Subpart IIII for compression ignition engines. Furthermore, this section states that no further Subpart ZZZZ requirements apply for this category of engines. The proposed emergency compression ignition engine powering the fire pump is a new engine and will be in compliance with 40 CFR 60 Subpart IIII; therefore, the proposed engine is in compliance with Subpart ZZZZ requirements.

40 CFR 63– Subpart DDDDD

Applicability

This subpart is applicable to boilers that are located at Major HAP Sources. This facility is not a major source of HAP emissions; therefore, this subpart is not applicable.

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). The following will be included on each permit:

- 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]

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

The CTG's lube oil vents will be limited by permit condition to not have visible emissions, except for three minutes in any hour, greater than 5% opacity as a BACT requirement and the exhaust stack emissions will be limited by permit condition to no greater than 20% opacity except for three minutes in any hour. Therefore compliance is expected. The following condition will be included on the each turbine permit:

- Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 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, compliance with this rule is expected.

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 for each unit. Under the District's risk management policy, Policy TOX 1, TBACT is not required for any proposed emissions unit as shown in the table below:

RMR Summary (See Attachment Q)							
Categories	Turbine (1-5)	Turbine (2-5)	Diesel ICE (4-2)	Boiler (5-0)	Fire pump (6-0)	Project Totals	Facility Totals
Prioritization Score	NA*	NA*	NA*	NA*	NA*	>1.0	>1.0
Acute Hazard Index	3.6e-2	3.3e-2	0.533	6.41e-4	0.188	0.79	0.79
Chronic Hazard Index	3.55e-2	3.53e-2	2.96e-5	7.64e-4	6.03e-5	0.07	0.07
Maximum Individual Cancer Risk (10^{-6})	0.5	0.47	0.079	0.019	0.159	1.24	1.24
T-BACT Required?	No	No	No	No	No		
Special Permit Conditions?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**		

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.

C. Special Conditions

<u>N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators</u>

The following special condition will be included on the permit to enforce Rule 4102 requirements:

- {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]

<u>N-4597-4-2: Emergency Generator Engine</u>

The following special condition will be included on the permit to enforce Rule 4102 requirements:

- Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201, 4102, and 4801 and 17 CCR 93115 and 40 CFR 60 4205(b)]

- Emissions from this IC engine shall not exceed 0.029 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 and 40 CFR 60 4205(b)]

- {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

N-4597-5-0: Auxiliary Boiler

No special conditions are required.

N-4597-6-0: Fire-Pump Engine

The following special condition will be included on the permit to enforce Rule 4102 requirements:

- Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201, 4102, and 4801 and 17 CCR 93115 and 40 CFR 60 4205(c)]
- Emissions from this IC engine shall not exceed 0.12 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 and 40 CFR 60.4205(c)]
- {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]

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.

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

$$PM\ Conc.\ (gr/scf) = \frac{(PM\ emission\ rate) \times (7000\ gr/lb)}{(Air\ flow\ rate) \times (60\ min/hr)}$$

Max PM_{10} emission rate = 5.8 lb/hr. Assuming 100% of PM is PM_{10}
H_2O = 9.25%
Exhaust Gas Flow, scfm (wet) = 535,953
Exhaust Gas Flow, dscfm = 535,953 ∗ [(100 – 9.25)/100] = 486,377 dscfm

PM Conc. (gr/scf)=[(5.8 lb/hr) ∗ (7,000 gr/lb)] ÷ [(486,377 ft^3/min) ∗ (60 min/hr)]
PM Conc. = 0.0014 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.

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

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

N-4597-4-2: Emergency Generator Engine

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:

$$0.029 \ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = \ 0.007 \ \frac{grain-PM}{dscf}$$

Since 0.007 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

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

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

N-4597-5-0: Auxiliary 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:	0.007 lb-PM10/MMBtu
Percentage of PM as PM10 in Exhaust:	100%
Exhaust Oxygen (O_2) Concentration:	3%

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

$$GL = \left(\frac{0.007\ lb-PM}{MMBtu} \times \frac{7{,}000\,grain}{lb-PM}\right) / \left(\frac{8{,}578\ ft^3}{MMBtu} \times 1.17\right)$$

$$GL = 0.0048\ grain/dscf < 0.1\,grain/dscf$$

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]

N-4597-6-0: Fire-Pump Engine

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:

$$0.12\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1bhp-hr}{2{,}542.5\,Btu} \times \frac{10^{6}\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.029\ \frac{grain-PM}{dscf}$$

Since 0.029 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

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

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

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to any of the proposed units 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".

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

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.

N-4597-4-2: Emergency Generator Engine

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

N-4597-5-0: Auxiliary Boiler

District Rule 4301 Limits			
Pollutant	NO_2	Total PM	SO_2
ATC N-4597-5-0 (lb/hr)	0.62	0.60	0.05
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

N-4597-6-0: Fire-Pump Engine

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

Rule 4304 Equipment Tuning Procedures for Boilers, Steam Generators, and Process Heaters

This rule is only applicable to unit N-4597-5-0

If tuning is required, the facility will be in compliance with the requirements of District Rule 4304.

Rule 4305 Boilers, Steam Generators, and Process Heaters – Phase II

This rule is only applicable to unit N-4597-5-0.

The unit is natural gas-fired with a maximum heat input of 85.0 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 and District Rule* 4320, *Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr.*

Since emissions limits of District Rule 4320 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4320 requirements will satisfy requirements of District Rule 4305.

Rule 4306 Boilers, Steam Generators, and Process Heaters – Phase III

This rule is only applicable to unit N-4597-5-0.

The unit is natural gas-fired with a maximum heat input of 85.0 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

In addition, the unit is also subject to *District Rule* 4320, *Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr.*

Since emissions limits of District Rule 4320 and all other requirements are equivalent or more stringent than District Rule 4306 requirements, compliance with District Rule 4320 requirements will satisfy requirements of District Rule 4306.

Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, And Process Heaters Greater than 5.0 MMBtu/hr

This rule is only applicable to unit N-4597-5-0.

The unit is natural gas-fired with a maximum heat input of 85.0 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4320, the unit is subject to District Rule 4320.

Section 5.2, NO_X and CO Emissions Limits

Section 5.2 requires that except for units subject to Sections 5.3, 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.

With a maximum heat input of 85.0 MMBtu/hr, the applicable emission limit category is listed in Section 5.2, Table 1, Category B, from District Rule 4320.

Rule 4320 Emissions Limits		
Category	Operated on gaseous fuel	
	NO_X Limit	CO Limit
B. Units with a total rated heat input greater than 20.0 MMBtu/hr, except for categories C through G units	7 ppmv or 0.008 lb/MMBtu	400 ppmv

The compliance deadline for meeting the NOx limit is July 1, 2010. The proposed boiler is scheduled to begin operation after July 1, 2010.

For the unit:

- the proposed NO_x emission factor is 6 ppmvd @ 3% O_2 (0.0073 lb/MMBtu), and
- the proposed CO emission factor is 50 ppmvd @ 3% O_2 (0.037 lb/MMBtu).

Therefore, compliance with Section 5.2 of District Rule 4320 is expected.

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

Section 5.3, Annual Fee Calculation

Annual Fees are required if the unit will not be meeting the emission limits in Section 5.2 of this rule. Since the proposed boiler will meet the emissions limits of Section 5.2, the annual fee requirements are not applicable.

Section 5.4, Particulate Matter Control Requirements

Section 5.4.1 of this rule requires the operator to comply with one of the following requirements:

1. Fire the boiler exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases;

2. Limit fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet;

3. Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight; or limit exhaust SO_2 to less than or equal to 9 ppmv corrected to 3.0% O_2;

GWF Tracy's proposed boiler is fired exclusively on PUC-quality natural gas. Therefore, this requirement has been satisfied.

Section 5.5, Low Use

The unit annual heat input will exceed the 1.8 billion Btu heat input per calendar year criteria limit addressed by this section. Since the unit is not subject to Section 5.5, the requirements of this section do not apply to the unit.

Section 5.6, Startup and Shutdown Provisions

Section 5.6 states that on and after the full compliance deadline in Section 5.0, the applicable emission limits of Sections 5.2 Table 1 and 5.5.2 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.6.1 through 5.6.5

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, this unit will be subject to the applicable emission limits of Section 5.2.

Section 5.7, Monitoring Provisions

Section 5.7.1 requires that permit units subject to District Rule 4320, Section 5.2 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 either install a CEMS system or to use a pre-approved alternate monitoring scheme to satisfy the requirements of this section. The following condition will assure compliance with this section. Further information on the alternate monitoring schemes available is included in Appendix S of this document.

- The exhaust stack shall either be equipped with a continuous emissions monitor (CEM) for NO_X, CO, and O_2 or the owner/operator shall implement one of the alternate monitoring schemes (A, B, C, D, E, F, or G) listed in District Rule 4320, Section 5.7.1 (dated 10/16/08). Owner/operator shall submit, in writing, the chosen method of monitoring (either CEMS or chosen alternate monitoring scheme) at least 30 days prior to initial operation of this boiler. [District Rules 2201, 4305, 4306 and 4320]

Since the unit is not subject to the requirements listed in Section 5.5.1 or 5.5.2, it is not subject to Section 5.7.2 and 5.7.3 requirements.

Section 5.7.4 allows units operated at seasonal sources and subject to 40 CFR 60 Subpart DB to install a parametric monitoring system in lieu of a CEMS. The proposed boiler is not operated at a seasonal source. Therefore, this unit is not subject to 5.7.4 requirements.

Section 5.7.6 outlines requirements for monitoring SOx emissions. Since this unit is fired solely on PUC-Quality natural gas, SOx emission monitoring is not required.

Section 5.8, Compliance Determination

Section 5.8.1 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:

- The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

Section 5.8.2 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:

- 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, 4306, and 4320]

Section 5.8.3 requires CEMS emission measurements to be averaged over a 15 consecutive-minute period. If a CEMS is chosen, the applicant is proposing to meet this requirement.

Section 5.8.4 requires that for emissions monitoring 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.

Section 5.8.5 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:

- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs (or longer periods as necessary) 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, 4306, and 4320]

Section 6.1, Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.5 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 condition will be listed on the permit as follows to ensure compliance:

- 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, 4306, and 4320]

Section 6.1.2 requires that the operator of a unit subject to Section 5.5 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 5.5, it is not subject to Section 6.1.2 requirements.

Section 6.1.3 requires that the operator of a unit subject to Section 5.5.1 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 6.1.4 requires that the operator of a unit with startup or shutdown provisions keep records of the duration of the startup or shutdowns. GWF Tracy has not proposed the use of startup and shutdown provisions, thus, the requirements of this section do not apply to the unit.

Section 6.1.5 requires that the operator of a unit fired on liquid fuel during PUC-quality natural gas curtailment periods record the sulfur content of the fuel, amount of fuel used, and duration of the natural gas curtailment period. GWF Tracy has not proposed the use of curtailment fuels; 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, 20 or ARB Method 100
NO_X	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10, 10B 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 or 19
Stack Gas Moisture Content	%	EPA Method 4

The following permit conditions will be listed on the permit:

- 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]
- NO_X emissions for source test purposes shall be determined using EPA Method 7E, 20 or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320]
- CO emissions for source test purposes shall be determined using EPA Method 10, 10B or ARB Method 100. [District Rules 4305, 4306, and 4320]
- Stack gas oxygen (O_2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]

Section 6.3, Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.2 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:

- {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, 4306, and 4320]
- 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, 4306, and 4320]
- 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 4320.

The proposed modified unit will be in compliance with the emissions limits listed in table 1, Section 5.2 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 4320. No further discussion is required.

Section 7.0, Compliance Schedule

Section 7.0 indicates that an operator of boilers must be in compliance with both the ATC deadline and compliance deadlines listed in Table 1 of Section 5.2.

The unit will be in compliance with the emissions limits listed in table 1, Section 5.2 of this rule, and periodic monitoring and source testing as required by District Rule 4320. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4320, 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 4320 requirements is expected.

Rule 4351 Boilers Steam Generators and Process Heaters – Phase 1

This rule is only applicable to unit N-4597-5-0.

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 4320. Therefore, compliance with this rule is expected.

Rule 4701 Internal Combustion Engines – Phase 1

This rule is only applicable to units N-4597-4-2 and N-4597-6-0.

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, the diesel-fired emergency IC engines 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 N-4597-4-2 and N-4597-6-0.

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

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

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

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

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

Therefore, unit N-4597-4-2, 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 N-4597-6-0, the emergency IC engine powering a firewater pump involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

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

1) Properly operate and maintain each engine as recommended by the engine manufacturer or emission control system supplier.

2) Monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier.

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

Therefore, the following conditions will be listed on ATC N-4597-4-2 to ensure compliance:

<u>N-4597-4-2: Emergency Generator Engine</u>

- 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 owner/operator 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 owner/operator. [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 and 17 CCR 93115]

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 ATCs to ensure compliance:

<u>N-4597-6-0: Fire-Pump Engine</u>

- 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", 2002 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 and 40 CFR 60.4211(e)]

- The owner/operator 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]

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

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

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 40 CFR 60.4309(a)]

- 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 owner/operator. [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]

N-4597-4-2: Emergency Generator Engine

- The owner/operator 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

N-4597-1 and N-4597-2:

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility is proposing to modify two 84.4 MW natural gas-fired turbines. Therefore the requirements of this rule apply to the proposed turbines.

Section 5.1 – NO_X Emission Requirements:

Section 5.1.1 of this Rule lists Tier 1 NOx requirements for turbines. These requirements are less stringent than the Tier 2 NOx requirements of Section 5.1.2; therefore, compliance with the Tier 2 NOx requirements of Section 5.1.2 guarantees satisfaction of Tier 1 NOx requirements.

Section 5.1.2 of this Rule lists Tier 2 NOx requirements for Turbines. Pursuant to Table 5-2, combined cycle turbines rated at 10 MW or greater are required to meet a NOx limit of 5 ppmvd @ 15% O_2, based on a 3-hour average. The applicant has a proposed a NOx limit of 2 ppmvd @ 15% O_2, based on a 1-hour average. Therefore, compliance with the Tier 2 NOx requirement is expected. The following conditions will be included on the permits:

- Emission rates from this CTG without the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 8.10 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.90 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 1.13 lb/hr and 1.5 ppmvd @ 15% O_2; PM_{10} – 4.40 lb/hr; or SO_X (as SO_2) – 2.03 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- Emission rates from this CTG with the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 10.30 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 6.00 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 3.22 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 5.80 lb/hr; or SO_X (as SO_2) – 2.63 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

Section 5.1.3 of this Rule lists Tier 3 NOx requirements. There are no Tier 3 NOx requirements listed for combined cycle turbines rated greater than 10 MW.

Section 5.2 – CO Emission Requirements:

Per Table 5-3 of section 5.2, the CO emissions concentration for GE Frame 7 turbines 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.

GWF Tracy 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 following conditions will be included on the permits:

- Emission rates from this CTG without the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 8.10 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.90 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 1.13 lb/hr and 1.5 ppmvd @ 15% O_2; PM_{10} – 4.40 lb/hr; or SO_X (as SO_2) – 2.03 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- Emission rates from this CTG with the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 10.30 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 6.00 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 3.22 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 5.80 lb/hr; or SO_X (as SO_2) – 2.63 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

<u>Section 5.3 – Startup and Shutdown Requirements:</u>

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.

GWF Tracy 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 three 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:

<u>A clear identification of the control technologies or strategies to be utilized; and</u>

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.

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

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.

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

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a maximum of three 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.

<u>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</u>

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.

<u>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</u>

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 manufacturer's recommended procedures.

Basis for the Requested Additional Duration

Pursuant to the vendor, the STG run-up curve for a comparable sized STG is 160 minutes from zero speed to full load. The HRSG ramp curve for a similar sized HRSG shows the unit will not produce steam until 20 minutes after the STG is started. The 180 minute cold start estimate from Black and Veatch is in agreement with the vendor data.

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, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 390.5 lb/event; CO – 562.5 lb/event; VOC (as methane) – 10.5 lb/event; PM_{10} – 11.0 lb/event; or SO_X (as SO_2) – 4.1 lb/event. [District Rules 2201 and 4703]

- During shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) –104.0 lb/event; CO – 148.0 lb/event; VOC (as methane) – 2.6 lb/event; PM_{10} – 3.0 lb/event; or SO_X (as SO_2) – 1.1 lb/event. [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 shall not exceed three hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

- The duration of each shutdown shall not exceed two 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 Record Keeping:

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 monitor emissions during all types of operation, including 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 existing turbines were installed after August 18, 1994. 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. GWF Tracy 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. GWF Tracy 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 owner/operator 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. GWF Tracy 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 owner/operator 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 owner/operator 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]

- The owner/operator shall maintain a system operating log, updated on a daily basis, which includes the following information: The actual start-up time and stop time, length and reason for any reduced load periods, total hours of operation, and type and quantity of fuel used. [District Rule 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, GWF Tracy 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.

Section 6.2.9 requires owners or operators of units subject to Section 5.1.3.3 of this Rule to keep additional records. These turbines are not subject to Section 5.1.3.3 of this Rule. Therefore, the requirements of this section are not applicable. No further discussion is required.

Section 6.2.10 requires the operator of a unit subject to section 6.5.2 to identify in the stationary gas turbine system operating log the date and start time and end time that the unit was operated pursuant to Section 6.5.2 and to keep a copy of the emergency declaration. Section 6.5.2 applies to emergency standby units. Since these turbines are not emergency standby units, the requirements of this section are not applicable. No further discussion is required.

Section 6.2.11 requires the operator of a unit to keep records of the date, time, and duration of each bypass transition period and each primary re-ignition period. The applicant has not requested any relief from Rule 4703 emission limits during bypass transition and primary re-ignition periods.

Section 6.2.12 requires the operator of a unit subject to subsection (b) of Table 5-3 to keep additional records. These units are not subject to subsection (b) of Table 5-3; therefore, the requirements of this section are not applicable. No further discussion is required.

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 GWF Energy 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 measure the NOx, CO, VOC, and NH3 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, 2201 and 4703 and 40 CFR 60.4400]

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

Section 6.3.3 specifies that the owner or operator of any unit with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off.

- Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance 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 dermtermined using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined 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 or ARB Method 100 and EPA Method 19 (Acid Rain Program); CO - EPA Method 10 or 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 and 202 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20 or ARB Method 100. NO_X testing shall also be conducted in accordance with the requirements of 40 CFR 60.4400(a)(2), (3), and (b). 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) and 60.4400(a)(2), (3), and (b)]

Section 6.5 of this rule lists requirements for exempt and emergency standby units. These turbines are neither exempt nor emergency standby units. Therefore, the requirements of this section 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 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:

N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators

The sulfur of the natural gas fuel is 0.66 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)
- $n = \frac{0.0007125 lb}{MMBtu} \times \frac{1\,(lb-mol)}{64\,lb} = 0.000011\,(lb-mol)$
- $R = \frac{0.7302\,ft^3 \cdot atm}{(lb-mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

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

$$V = \frac{0.000011\,(lb-mol) \cdot \frac{0.7302\,ft^3 \cdot atm}{(lb-mol)\,°R} \cdot 500\,°R}{1\,atm}$$

$$V = 0.004\,ft^3$$

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

$$= \frac{0.004}{8{,}578} = 0.00000047 = 0.47\ ppmv = 0.000047\%\ by\ volume$$

0.47 ppmv ≤ 2000 ppmv, therefore the turbines are expected to comply with Rule 4801.

<u>N-4597-4-2: Emergency Generator Engine</u>

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) = $\frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot °R}$

$$\frac{0.000015\,lb-S}{lb-fuel} \times \frac{7.1\,lb}{gal} \times \frac{64\,lb-SO_2}{32\,lb-S} \times \frac{1\,MMBtu}{9{,}051\,scf} \times \frac{1\,gal}{0.137\,MMBtu} \times \frac{lb-mol}{64\,lb-SO_2} \times \frac{10.73\,psi-ft^3}{lb-mol-°R} \times \frac{520°R}{14.7\,psi} \times 1{,}000{,}000 = 1.0\ ppmv$$

1.0 ppmv ≤ 2000 ppmv, therefore the emergency engine is expected to comply with Rule 4801.

Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201, 4102, and 4801 and 17 CCR 93115]

<u>N-4597-5-0: Auxiliary Boiler</u>

The sulfur of the natural gas fuel is 0.66 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)
- $n = \frac{0.0007125 lb}{MMBtu} \times \frac{1\,(lb - mol)}{64\ lb} = 0.000011\,(lb - mol)$
- $R = \frac{0.7302\, ft^3 \cdot atm}{(lb - mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

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

$$V = \frac{0.000011\,(lb - mol) \cdot \frac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.004\ ft^3$$

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

$$= \frac{0.004}{8{,}578} = 0.00000047 = 0.47\ ppmv = 0.000047\%\ by\ volume$$

0.47 ppmv ≤ 2000 ppmv, therefore the boiler is expected to comply with Rule 4801.

N-4597-6-0: Fire-Pump Engine

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) = $\frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot °R}$

$$\frac{0.000015\ lb - S}{lb - fuel} \times \frac{7.1\ lb}{gal} \times \frac{64\ lb - SO_2}{32\ lb - S} \times \frac{1\ MMBtu}{9{,}051\ scf} \times \frac{1\ gal}{0.137\ MMBtu} \times \frac{lb - mol}{64\ lb - SO_2} \times \frac{10.73\ psi - ft^3}{lb - mol - °R} \times \frac{520°R}{14.7\ psi} \times 1{,}000{,}000 = 1.0\ ppmv$$

1.0 ppmv ≤ 2000 ppmv, therefore the emergency engine is expected to comply with Rule 4801.

Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201, 4102, and 4801 and 17 CCR 93115 and 40 CFR 60.4207]

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] N

- 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, owner/operator 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, Owner/operator 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 California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The San Joaquin Valley Unified Air Pollution Control District (District) adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.

- Identify the ways that environmental damage can be avoided or significantly reduced.

- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.

- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The California Energy Commission (CEC) has the exclusive power to certify all thermal electric power plants greater than 50 MW in the State of California (Public Resources Code § 25500). While the CEC siting process is exempt from CEQA (14 CCR § 15251(k)), it is functionally equivalent to CEQA.

The District holds no discretionary approval powers over this project; however the District prepares a Determination of Compliance (DOC), this document. The DOC confers the rights and privileges of an Authority to Construct upon certification by the CEC, where the CEC certificate contains the conditions set forth in this DOC (20 CCR § 1744.5 and Rule 2201 § 5.8.8). A Permit to Operate is required to be issued if the project receives a certificate from the CEC and the project is constructed in accordance with the conditions set forth in the DOC (Rule 2201 § 5.8.9). The District makes the following findings regarding this project: the District holds no discretionary approval powers over this project and the District's actions are ministerial (CEQA Guidelines § 15369).

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)

N-4597-4-2: Emergency Generator Engine

This application does not involve a new engine, an engine that was installed without first getting an ATC from the District, or an in-use engine being retrofitted with a PM_{10} control device to meet the ATCM requirements. Therefore, the engine involved with this application is not required to meet the requirements of Title 13 California Code of Regulations (CCR), Section 2423 and no further discussion is required.

N-4597-6-0: Fire-Pump Engine

Title 13 California Code of Regulations (CCR) Section 2423 outlines requirements for an engine to be certified by ARB. The certification dates for Firepump Engines have been extended; therefore, Tier II is currently the latest certification available for firepump engines; however, at the time of installation the applicant will be required to install a Tier 3 IC engine. The applicant has proposed the use of a Tier 3 IC engine. Therefore, the engine is expected to meet all the requirements of Title 13 CCR Section 2423.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

N-4597-4-2: Emergency Generator Engine

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- 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," 2002 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 following conditions will be included on the permit to ensure compliance with this requirement:

- The owner/operator 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]

- 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 In-Use Emergency Diesel Engines:

This engine has a PM10 emissions limit of 0.029 g-PM10/bhp-hr. This regulation stipulates that as of January 1, 2005, no person shall operate any in-use 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 for engines rated between 0.01 and 0.15 g-PM10/bhp:

1. Meets the appropriate 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
2. 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 an emergency generator will meet the above requirements. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- Emissions from this IC engine shall not exceed 0.029 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]

- 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 Rules 4702 and 17 CCR 93115]

N-4597-6-0: Fire-Pump Engine

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- 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 and 40 CFR 60.4207]

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," 2002 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 emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- {3489} The owner/operator 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 0.12 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 100 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 PM emissions rate limitation because the engine is rated at 49.6 to 174.2 bhp and is also exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the ATC to ensure compliance:

- Emissions from this IC engine shall not exceed 0.12 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 and 40 CFR 60.4205(c)]

- 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", 2002 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 and 40 CFR 60.4211(e)]

40 CFR Part 51 Appendix S Requirements for $PM_{2.5}$

40 CFR 51 Appendix S requirements are applicable to new major $PM_{2.5}$ sources and federal major modifications for $PM_{2.5}$. The significance thresholds are as follows:

$PM_{2.5}$ major source threshold	100 ton/year
$PM_{2.5}$ federal major modification threshold	10 ton/year

As discussed in Section VII.C.5 above, the facility is not a Major Source for PM_{10} emissions. As $PM_{2.5}$ is a subset of PM_{10}, and the $PM_{2.5}$ Major Source threshold is greater than the PM_{10} Major Source threshold, this facility is not a Major Source for $PM_{2.5}$ emissions. Therefore, Appendix S requirements for $PM_{2.5}$ are not applicable and no further discussion is required.

IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Preliminary 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
N-4597-1-5	3020-08A-H	156,900 kW	$13,208
N-4597-2-5	3020-08A-H	156,900 kW	$13,208
N-4597-4-2	3020-10-D	471 BHP	$479
N-4597-5-0	3020-02-H	88 MMBtu/hr	$1,030
N-4597-6-0	3020-10-C	288 BHP	$240

ATTACHMENT A

FDOC CONDITIONS

N-4597-1-5: MODIFICATION OF AN EXISTING 84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST: TO CONVERT THE EXISTING SYSTEM TO A COMBINED CYCLE CONFIGURATION BY (1) REMOVING THE EXISTING OXIDATION AND SELECTIVE CATALYTIC REDUCTION SYSTEM AND THE EXISTING 100 FOOT EXHAUST STACKS, (2) INSTALLING A NEW HEAT RECOVERY STEAM GENERATOR EQUIPPED WITH A 324 MMBTU/HR (HHV) NATURAL GAS-FIRED DUCT BURNER, (3) INSTALLING A NEW OXIDATION CATALYST AND NEW SELECTIVE CATALYTIC REDUCTION SYSTEM, (4) INSTALLING A NEW 150' TALL 17' DIAMETER STACK, (5) INSTALLING A NEW STG LUBE OIL COOLER, AND (6) INSTALLING A 145 MW NOMINALLY RATED CONDENSING STEAM TURBINE GENERATOR (SHARED WITH N-4597-2)

1. The owner/operator shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

2. To the extent this Determination of Compliance serves as an Authority to Construct, said Authority to Construct shall not become effective until the California Energy Commission approves the Application for Certification. [California Environmental Quality Act and District Rule 2201, Section 5.8.8]

3. This Determination of Compliance serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]

4. Prior to operating with modifications authorized by this Determination of Compliance, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

5. The owner/operator of GWF Tracy shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions # 6 through #16 shall apply only during the commissioning period as defined below. Unless otherwise indicated, conditions #17 through #101 shall apply after the commissioning period has ended. [District Rule 2201]

6. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning and calibration activities recommended by the equipment manufacturers and the GWF Tracy construction contractor to insure safe and reliable steady state operation of the gas turbine, heat recovery steam generators, steam turbine, and associated electrical delivery systems. [District Rule 2201]

7. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the gas turbine is first fired (at the beginning of the conversion to a combined cycle plant), whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

8. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

9. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

10. Coincident with the steady state operation of the SCR system and the oxidation catalyst at loads greater than 50% and after installation and tuning of emission controls, NOx, CO, and VOC emissions from this unit shall comply with the limits specified in conditions #30 and #31 of this permit. [District Rule 2201]

11. The owner/operator shall submit a plan to the District at least four weeks prior to first firing of this unit (after beginning of the conversion to a combined cycle plant), describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of each activity. The activities described shall include, but not limited to, the tuning of the combustors, the installation and operation of the SCR system and oxidation catalyst, the installation, calibration, and testing of NOx and CO continuous emission monitors, and any activities requiring firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

12. Emission rates from the CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) – 146.70 lb/hr; PM10 – 5.80 lb/hr; VOC (as methane) – 3.20 lb/hr; CO – 229.60 lb/hr; SOx (as SO2) – 2.6 lb/hr. [District Rule 2201]

13. During the initial commissioning activities, the owner/operator shall demonstrate compliance with the NOx emission limit specified in condition #12 through the use of properly operated and maintained continuous emission monitor located within the inlet section of the steam generator unit. Upon completion of the initial commission activities and with the installation of the SCR system and oxidation catalyst, the owner/operator shall demonstrate compliance with the NOx and CO emission limits specified in conditions #30, #31, #32, and #33 through the use of properly operated and maintained continuous emission monitors and recorders as specified in conditions #55 and #56. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

14. During initial commissioning activities, the inlet NOx continuous emissions monitor specified in this permit shall be installed, calibrated, and operation prior to the first re-firing of this unit. Upon completion of the initial commissioning activities and the installation of the SCR system and oxidation catalyst, the exhaust stack NOx and CO continuous monitors specified within this permit shall be installed, calibrated, and operational prior to the first re-firing of this unit with the SCR and oxidation catalyst in place. After the first re-firing, the detection range of each continuous emissions monitor shall be adjusted as necessary to accurately measure the resulting range of NOx and/or CO emission concentrations. [District Rule 2201]

15. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 500 hours total during the commissioning period. Such operation of the unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and oxidation catalyst in place. Upon completion of these activities, the owner/operator shall proved written notice to the District and the unused balance of the 500 firing hours without abatement shall expire. Records of the commissioning hours for this unit shall be maintained. [District Rule 2201]

16. The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limit specified in condition #41. [District Rule 2201]

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

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

19. 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]

20. Owner/operator 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]

21. 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]

22. 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]

23. 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]

24. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

25. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The owner/operator shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

26. During all types of operation, including startup and shutdown periods, ammonia injection in to the SCR system shall occur once the minimum temperature at the catalyst face has been reached to ensure NO_X emission reductions can occur with a reasonable level of ammonia slip. The minimum catalyst face temperature shall be determined during the final design phase of this project and shall be submitted to the District at least 30 days prior to commencement of construction. [District Rule 2201]

27. The SCR system shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the catalyst face. [District Rule 2201]

28. Owner/operator shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

29. The CTG shall only be fired on PUC-regulated natural gas with a sulfur content value not exceeding 0.66 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a daily basis and 0.25 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a 12-month rolling average basis. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

30. Emission rates from this CTG without the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 8.10 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.90 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 1.13 lb/hr and 1.5 ppmvd @ 15% O_2; PM_{10} – 4.40 lb/hr; or SO_X (as SO_2) – 2.03 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

31. Emission rates from this CTG with the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 10.30 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 6.00 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 3.22 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 5.80 lb/hr; or SO_X (as SO_2) – 2.63 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

32. During start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 390.5 lb/event; CO – 562.5 lb/event; VOC (as methane) – 10.5 lb/event; PM_{10} – 11.0 lb/event; or SO_X (as SO_2) – 4.1 lb/event. [District Rules 2201 and 4703]

33. During shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) –104.0 lb/event; CO – 148.0 lb/event; VOC (as methane) – 2.6 lb/event; PM_{10} – 3.0 lb/event; or SO_X (as SO_2) – 1.1 lb/event. [District Rules 2201 and 4703]

34. A start up event is defined as the period beginning with the gas turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in Condition 30 or Condition 31 depending on the operating conditions of the duct burners during the start up event. A shutdown event is defined as the period beginning with the turbine shutdown sequence and ending with the cessation of firing the gas turbine engine. [District Rules 2201 and 4703]

35. The duration of each startup shall not exceed three hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. The duration of each shutdown shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

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

38. The ammonia (NH_3) emissions shall not exceed 5 ppmvd @ 15% O_2 or 9.40 lb/hr over a 24 hour rolling average. [District Rules 2201 and 4102]

39. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the owner/operator shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the owner/operator may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the owner/operator shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

40. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 814.9 lb/day; CO – 1071.6 lb/day; VOC – 78.6 lb/day; PM_{10} – 132.0 lb/day; or SO_X (as SO_2) – 58.7 lb/day. [District Rule 2201]

41. Annual emissions from the CTG, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 88,881 lb/year; CO – 74,598 lb/year; VOC – 15,145 lb/year; PM_{10} – 32,250 lb/year; or SO_X (as SO_2) – 7,084 lb/year. Compliance with the annual NOx and CO emission limits shall be demonstrated using CEM data and compliance with the annual VOC, PM10 and SOx emission limits shall be demonstrated using the most recent source test results. [District Rule 2201]

42. 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 rolling 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]

43. 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]

44. The combined natural gas fuel usage for permit units N-4597-1 and N-4597-2 shall not exceed 20,454 MMscf/year. [District Rule 2550]

45. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_X, CO, and O_2 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]

46. Source testing to measure the stead state NOx, CO, VOC, and NH3 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, 2201 and 4703 and 40 CFR 60.4400]

47. Source testing to measure the PM10 emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081, 2201 and 40 CFR 60.4400]

48. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (N-4597-1 or N-4597-2) within 60 days after the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NO_X and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081 and 2201]

49. Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703]

50. 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]

51. The following test methods shall be used: NOx - EPA Method 7E or 20 or ARB Method 100 and EPA Method 19 (Acid Rain Program); CO - EPA Method 10 or 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 and 202 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or ARB 100. NOx testing shall also be conducted in accordance with the requirements of 40 CFR 60.4400(a)(2), (3), and (b). 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) and 40 CFR 60.4400(a)(2), (3), and (b)]

52. Testing to demonstrate compliance with the short-term (daily) fuel sulfur content limit shall be conducted monthly. If a monthly test indicates that a violation of the daily fuel sulfur content limit has occurred then weekly testing shall commence and continue until eight consecutive tests show compliance. Once compliance with the daily fuel sulfur content is demonstrated on eight consecutive weekly tests, testing may return to the monthly schedule. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. [District Rule 2201 an 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

53. Compliance with the rolling 12-month average fuel sulfur content limit shall be demonstrated monthly. The 12-month rolling average fuel sulfur content shall be calculated as follows: 12-month rolling average fuel sulfur content = Sum of the monthly average fuel sulfur contents for the previous 12 months ÷ total number of months the unit has operated in during the previous 12 months. The monthly average fuel sulfur content is the average fuel sulfur content of all tests conducted in a given month. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. Owner/operator shall keep a monthly record of the rolling 12-month average fuel sulfur content. [District Rules 1081 and 2201]

54. 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)]

55. The CTG shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703]

56. 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 monitor emissions during all types of operation, including during startup and shutdown periods, 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 60.4335(b)(1)]

57. 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)]

58. 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 Specifications 2, 3, and 4, and/or 40 CFR 75 Appendix A, 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)]

59. 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]

60. 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, or 40 CFR Part 75 Appendix B, at least once every four calendar quarters. The owner/operator 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. If the RATA test is conducted as specified in 40 CFR Part 75 Appendix B, the RATA shall be conducted on a lb/MMBtu basis. [District Rule 1080 and 40 CFR 60.4345]

61. 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]

62. The owner/operator shall develop and keep onsite a quality assurance plan for all the continuous monitoring equipment described in 40 CFR 60.4345(a), (c), and (d). [40 CFR 60.4345(e)]

63. 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 40 CFR 60.13. [District Rule 4703 and 40 CFR 60.13 and 40 CFR 60.4350(a)]

64. 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]

65. 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]

66. 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]

67. Excess NOx emissions shall be defined as any 30 day operating period in which the 30 day rolling average NOx concentration exceeds an applicable emissions limit. A 30 day rolling average NOx emission rate is the arithmetic average of all hourly NOx emission data in ppm measured by the continuous 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 NOx emission rates for the preceding 30 unit operating days if a valid NOx emission rate is obtained for at least 75 percent of all operating hours. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx or O2 (or both). [40 CFR 60.4350(h) and 40 CFR 60.4380(b)(1)]

68. For the purpose of determining excess NOx emissions, for each unit operating hour in which a valid hourly average is obtained, the data acquisition system and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 of 40 CFR 60 Appendix A. For any hour in which the hourly O2 concentration exceeds 19.0 percent O2, a diluent cap value of 19 percent O2 may be used in the emission calculations. [40 CFR 60.4350(b)]

69. Excess SOx emissions is each unit operating hour included in the period beginning on the dat and hour of any sample for which the fuel sulfur content exceeds the applicable limits listed in this permit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. Monitoring downtime for SOx begins when a sample is not taken by its due date. A period of monitor downtime for SOx also begins on the date and hour of a required sample, if invalid results are obtained. A period of SOx monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)]

70. 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]

71. The owner/operator 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]

72. The owner/operator 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]

73. The owner/operator 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, calculated NOx and CO mass emission rates (lb/hr and lb/twelve month rolling period), and VOC, PM10 and SOx emission rates (lb/twelve month rolling period). [District Rules 2201 and 4703]

74. The owner/operator shall maintain a system operating log, updated on a daily basis, which includes the following information: The actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and type and quantity of fuel used. [District Rule 4703]

75. 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]

76. The owners and operators of each affected source and each affected unit at the source shall: (i) Operate the unit in compliance with a complete Acid Rain permit application or a superceding Acid Rain permit issued by the permitting authority; and (ii) have an Acid Rain permit. [40 CFR 72]

77. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75]

78. The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75]

79. The owners and operators of each source and each affected unit at the source shall: (i) hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73]

80. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77]

81. An affected unit shall be subject to the sulfur dioxide requirements starting on the later of January 1, 2000, or the deadline for monitoring certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3) that is not a substitution or compensating unit. [40 CFR 72, 40 CFR 75]

82. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72]

83. An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73]

84. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72]

85. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72]

86. The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides. [40 CFR 72]

87. The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77]

88. The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77]

89. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72]

90. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 72, 40 CFR 75]

91. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75]

92. 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]

93. 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]

94. 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]

95. 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] N

96. 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]

97. 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]

98. 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]

99. 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, owner/operator 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]

100. Whenever any portion of the site becomes inactive, Owner/operator 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]

101. 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]

N-4597-2-6: MODIFICATION OF AN EXISTING 84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST: TO CONVERT THE EXISTING SYSTEM TO A COMBINED CYCLE CONFIGURATION BY (1) REMOVING THE EXISTING OXIDATION AND SELECTIVE CATALYTIC REDUCTION SYSTEM AND THE EXISTING 100 FOOT EXHAUST STACKS, (2) INSTALLING A NEW HEAT RECOVERY STEAM GENERATOR EQUIPPED WITH A 324 MMBTU/HR (HHV) NATURAL GAS-FIRED DUCT BURNER, (3) INSTALLING A NEW OXIDATION CATALYST AND NEW SELECTIVE CATALYTIC REDUCTION SYSTEM, (4) INSTALLING A NEW 150' TALL 17' DIAMETER STACK, (5) INSTALLING A NEW STG LUBE OIL COOLER, AND (6) INSTALLING A 145 MW NOMINALLY RATED CONDENSING STEAM TURBINE GENERATOR (SHARED WITH N-4597-1)

1. The owner/operator shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

2. To the extent this Determination of Compliance serves as an Authority to Construct, said Authority to Construct shall not become effective until the California Energy Commission approves the Application for Certification. [California Environmental Quality Act and District Rule Rule 2201, Section 5.8.8]

3. This Determination of Compliance serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]

4. Prior to operating with modifications authorized by this Determination of Compliance, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

5. The owner/operator of GWF Tracy shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions # 6 through #16 shall apply only during the commissioning period as defined below. Unless otherwise indicated, conditions #17 through #101 shall apply after the commissioning period has ended. [District Rule 2201]

6. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning and calibration activities recommended by the equipment manufacturers and the GWF Tracy construction contractor to insure safe and reliable steady state operation of the gas turbine, heat recovery steam generators, steam turbine, and associated electrical delivery systems. [District Rule 2201]

7. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the gas turbine is first fired (at the beginning of the conversion to a combined cycle plant), whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

8. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

9. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

10. Coincident with the steady state operation of the SCR system and the oxidation catalyst at loads greater than 50% and after installation and tuning of emission controls, NOx, CO, and VOC emissions from this unit shall comply with the limits specified in conditions #30 and #31 of this permit. [District Rule 2201]

11. The owner/operator shall submit a plan to the District at least four weeks prior to first firing of this unit (after beginning of the conversion to a combined cycle plant), describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of each activity. The activities described shall include, but not limited to, the tuning of the combustors, the installation and operation of the SCR system and oxidation catalyst, the installation, calibration, and testing of NOx and CO continuous emission monitors, and any activities requiring firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

12. Emission rates from the CTG, during the commissioning period, shall not exceed any of the following limits: NOx (as NO2) – 146.70 lb/hr; PM10 – 5.80 lb/hr; VOC (as methane) – 3.20 lb/hr; CO – 229.60 lb/hr; SOx (as SO2) – 2.6 lb/hr. [District Rule 2201]

13. During the initial commissioning activities, the owner/operator shall demonstrate compliance with the NOx emission limit specified in condition #12 through the use of properly operated and maintained continuous emission monitor located within the inlet section of the steam generator unit. Upon completion of the initial commission activities and with the installation of the SCR system and oxidation catalyst, the owner/operator shall demonstrate compliance with the NOx and CO emission limits specified in condition #30, #31, #32, and #33 through the use of properly operated and maintained continuous emission monitors and recorders as specified in conditions #55 and #56. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

14. During initial commissioning activities, the inlet NOx continuous emissions monitor specified in this permit shall be installed, calibrated, and operation prior to the first re-firing of this unit. Upon completion of the initial commissioning activities and the installation of the SCR system and oxidation catalyst, the exhaust stack NOx and CO continuous monitors specified within this permit shall be installed, calibrated, and operational prior to the first re-firing of this unit with the SCR and oxidation catalyst in place. After the first re-firing, the detection range of each continuous emissions monitor shall be adjusted as necessary to accurately measure the resulting range of NOx and/or CO emission concentrations. [District Rule 2201]

15. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 500 hours total during the commissioning period. Such operation of the unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and oxidation catalyst in place. Upon completion of these activities, the owner/operator shall proved written notice to the District and the unused balance of the 500 firing hours without abatement shall expire. Records of the commissioning hours for this unit shall be maintained.

16. The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limit specified in condition #41. [District Rule 2201]

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

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

19. 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]

20. Owner/operator 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]

21. 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]

22. 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]

23. 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]

24. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for up to three minutes in any hour. [District Rules 2201 and 4101]

25. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The owner/operator shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

26. During all types of operation, including startup and shutdown periods, ammonia injection in to the SCR system shall occur once the minimum temperature at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The minimum catalyst face temperature shall be determined during the final design phase of this project and shall be submitted to the District at least 30 days prior to commencement of construction. [District Rule 2201]

27. The SCR system shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the catalyst face. [District Rule 2201]

28. Owner/operator shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

29. The CTG shall only be fired on PUC-regulated natural gas with a sulfur content value not exceeding 0.66 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a daily basis and 0.25 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a 12-month rolling average basis. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

30. Emission rates from this CTG without the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 8.10 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.90 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 1.13 lb/hr and 1.5 ppmvd @ 15% O_2; PM_{10} – 4.40 lb/hr; or SO_X (as SO_2) – 2.03 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

31. Emission rates from this CTG with the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 10.30 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 6.00 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 3.22 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 5.80 lb/hr; or SO_X (as SO_2) – 2.63 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

32. During start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 390.5 lb/event; CO – 562.5 lb/event; VOC (as methane) – 10.5 lb/event; PM_{10} – 11.0 lb/event; or SO_X (as SO_2) – 4.1 lb/event. [District Rules 2201 and 4703]

33. During shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) –104.0 lb/event; CO – 148.0 lb/event; VOC (as methane) – 2.6 lb/event; PM_{10} – 3.0 lb/event; or SO_X (as SO_2) – 1.1 lb/event. [District Rules 2201 and 4703]

34. A start up event is defined as the period beginning with the gas turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in Condition 30 or Condition 31 depending on the operating conditions of the duct burners during the start up event. A shutdown event is defined as the period beginning with the turbine shutdown sequence and ending with the cessation of firing the gas turbine engine. [District Rules 2201 and 4703]

35. The duration of each startup shall not exceed three hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. The duration of each shutdown shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

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

38. The ammonia (NH_3) emissions shall not exceed 5 ppmvd @ 15% O_2 or 9.40 lb/hr over a 24 hour rolling average. [District Rules 2201 and 4102]

39. Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. If this option is chosen, the owner/operator shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the owner/operator may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the owner/operator shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

40. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 814.9 lb/day; CO – 1071.6 lb/day; VOC – 78.6 lb/day; PM_{10} – 132.0 lb/day; or SO_X (as SO_2) – 58.7 lb/day. [District Rule 2201]

41. Annual emissions from the CTG, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 88,881 lb/year; CO – 74,598 lb/year; VOC – 15,145 lb/year; PM_{10} – 32,250 lb/year; or SO_X (as SO_2) – 7,084 lb/year. Compliance with the annual NOx and CO emission limits shall be demonstrated using CEM data and compliance with the annual VOC, PM10 and SOx emission limits shall be demonstrated using the most recent source test results. [District Rule 2201]

42. 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 rolling 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]

43. 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]

44. The combined natural gas fuel usage for permit units N-4597-1 and N-4597-2 shall not exceed 20,454 MMscf/year. [District Rule 2550]

45. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_X, CO, and O_2 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]

46. Source testing to measure the stead state NOx, CO, VOC, and NH3 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, 2201 and 4703 and 40 CFR 60.4400]

47. Source testing to measure the PM10 emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081, 2201 and 40 CFR 60.4400]

48. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (N-4597-1 or N-4597-2) within 60 days after the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NO_X and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081 and 2201]

49. Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703]

50. 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]

51. The following test methods shall be used: NOx - EPA Method 7E or 20 or ARB Method 100 and EPA Method 19 (Acid Rain Program); CO - EPA Method 10 or 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 and 202 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or ARB Method 100. NOx testing shall also be conducted in accordance with the requirements of 40 CFR 60.4400(a)(2), (3), and (b). 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) and 40 CFR 60.4400(a)(2), (3), and (b)]

52. Testing to demonstrate compliance with the short-term (daily) fuel sulfur content limit shall be conducted monthly. If a monthly test indicates that a violation of the daily fuel sulfur content limit has occurred then weekly testing shall commence and continue until eight consecutive tests show compliance. Once compliance with the daily fuel sulfur content is demonstrated on eight consecutive weekly tests, testing may return to the monthly schedule. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. [District Rule 2201 an 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

53. Compliance with the rolling 12-month average fuel sulfur content limit shall be demonstrated monthly. The 12-month rolling average fuel sulfur content shall be calculated as follows: 12-month rolling average fuel sulfur content = Sum of the monthly average fuel sulfur contents for the previous 12 months ÷ total number of months the unit has operated in during the previous 12 months. The monthly average fuel sulfur content is the average fuel sulfur content of all tests conducted in a given month. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. Owner/operator shall keep a monthly record of the rolling 12-month average fuel sulfur content. [District Rules 1081 and 2201]

54. 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)]

55. The CTG shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703]

56. 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 monitor emissions during all types of operation, including startup and shutdown periods, 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 60.4335(b)(1)]

57. 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)]

58. 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 Specifications 2, 3, and 4, and/or 40 CFR 75 Appendix A, 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)]

59. 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]

60. 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, or 40 CFR Part 75 Appendix B, at least once every four calendar quarters. The owner/operator 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. If the RATA test is conducted as specified in 40 CFR Part 75 Appendix B, the RATA shall be conducted on a lb/MMBtu basis. [District Rule 1080 and 40 CFR 60.4345]

61. 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]

62. The owner /operator shall develop and keep onsite a quality assurance plan for all the continuous monitoring equipment described in 40 CFR 60.4345(a), (c), and (d). [40 CFR 60.4345(e)]

63. 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 40 CFR 60.13. [District Rule 4703 and 40 CFR 60.13 and 40 CFR 60.4350(a)]

64. 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]

65. 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]

66. 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]

67. Excess NOx emissions shall be defined as any 30 day operating period in which the 30 day rolling average NOx concentration exceeds an applicable emissions limit. A 30 day rolling average NOx rate is the arithmetic average of all hourly NOx emission data in ppm measured by the continuous 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 NOx emission rates for the preceding 30 unit operating days if a valid NOx emission rate is obtained for at least 75 percent of all operating hours. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx or O2 (or both). [40 CFR 60.4350(h) and 40 CFR 60.4380(b)(1)]

68. For the purpose of determining excess NOx emissions, for each unit operating hour in which a valid hourly average is obtained, the data acquisition system and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 of 40 CFR 60 Appendix A. For any hour in which the hourly O2 concentration exceeds 19.0 percent O2, a diluent cap of 19 percent O2 may be used in the emission calculations. [40 CFR 60.4350(b)]

69. Excess SOx emissions is each unit operating hour included in the period beginning on the dat and hour of any sample for which the fuel sulfur content exceeds the applicable limits listed in this permit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. Monitoring downtime for SOx begins when a sample is not taken by its due date. A period of monitor downtime for SOx also begins on the date and hour of a required sample, if invalid results are obtained. A period of SOx monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)]

70. 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]

71. The owner/operator 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]

72. The owner/operator 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]

73. The owner/operator 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, calculated NOx and CO mass emission rates (lb/hr and lb/twelve month rolling period), and VOC, PM10 and SOx emission rates (lb/twelve month rolling period). [District Rules 2201 and 4703]

74. The owner/operator shall maintain a system operating log, updated on a daily basis, which includes the following information: The actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and type and quantity of fuel used. [District Rule 4703]

75. 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]

76. The owners and operators of each affected source and each affected unit at the source shall: (i) Operate the unit in compliance with a complete Acid Rain permit application or a superceding Acid Rain permit issued by the permitting authority; and (ii) have an Acid Rain permit. [40 CFR 72]

77. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75]

78. The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75]

79. The owners and operators of each source and each affected unit at the source shall: (i) hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73]

80. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77]

81. An affected unit shall be subject to the sulfur dioxide requirements starting on the later of January 1, 2000, or the deadline for monitoring certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3) that is not a substitution or compensating unit. [40 CFR 72, 40 CFR 75]

82. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72]

83. An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73]

84. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72]

85. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72]

86. The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides. [40 CFR 72]

87. The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77]

88. The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77]

89. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72]

90. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 72, 40 CFR 75]

91. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75]

92. 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]

93. 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]

94. 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]

95. 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] N

96. 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]

97. 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]

98. 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]

99. 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, owner/operator 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]

100. Whenever any portion of the site becomes inactive, Owner/operator 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]

101. 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]

N-4597-4-2: MODIFICATION OF A 471 HP CATERPILLAR MODEL 3456 DI TA AA DIESEL-FIRED EMERGENCY IC ENGINE POWERING A 300 KW ELECTRICAL GENERATOR TO REDUCE THE ANNUAL HOURS OF OPERATION FOR MAINTENANCE AND TESTING FROM 200 HOURS/YEAR TO 50 HOURS/YEAR

1. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]

2. Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

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

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

5. 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. 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. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

8. Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201, 4102, and 4801 and 17 CCR 93115]

9. Emissions from this IC engine shall not exceed any of the following limits: 4.69 g-NOx/bhp-hr, 0.12 g-CO/bhp-hr, or 0.04 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

10. Emissions from this IC engine shall not exceed 0.029 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 and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

12. During periods of operation for maintenance, testing, and required regulatory purposes, the owner/operator 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. 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 owner/operator. [District Rule 4702]

14. This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

15. 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 Rules 4702 and 17 CCR 93115]

16. The owner/operator 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. 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]

N-4597-5-0: 85 MMBTU/HR NATURAL GAS-FIRED RENTECH MODEL RTD-2-60 BOILER WITH A COEN MODEL C-RMB BURNER AND FLUE GAS RECIRCULATION OR EQUIVALENT

1. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]
2. Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
5. 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. The owner/operator shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]
7. The owner/operator's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]
8. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]
9. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]
10. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
11. The flue gas recirculation (FGR) system shall be operated properly and shall be maintained per the manufacturer's recommendations. [District Rule 2201]

12. 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. The fuel meter shall be calibrated per the fuel meter manufacturers recommendations. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

13. The boiler shall operate a maximum of 4,000 hours per calendar year. [District Rule 2201]

14. The boiler shall only be fired on PUC-regulated natural gas with a sulfur content value not exceeding 0.66 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a daily basis and 0.25 grains of sulfur compounds (as S) per 100 dry standard cubic feet on a 12-month rolling average basis. [District Rule 2201]

15. Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) – 6 .0 ppmvd @ 3% O2 or 0.0073 lb/MMBtu; VOC (as methane) – 0.005 lb/MMBtu; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.007 lb/MMBtu; or SOx (as SO2) - 0.0019 lb/MMBtu. [District Rules 2201, 4305, 4306, 4320, and 4351]

16. 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, 4306, and 4320]

17. 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, 4306, and 4320]

18. 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, 4306, and 4320]

19. 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]

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

21. The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

22. For emissions source testing, the arithmetic average of three 30-consecutive-minute (or longer periods as necessary) 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, 4306, and 4320]

23. 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, 4306, and 4320]

24. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306, and 4320]

25. Stack gas oxygen (O_2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]

26. Testing to demonstrate compliance with the short-term (daily) fuel sulfur content limit shall be conducted monthly. If a monthly test indicates that a violation of the daily fuel sulfur content limit has occurred then weekly testing shall commence and continue until eight consecutive tests show compliance. Once compliance with the daily fuel sulfur content is demonstrated on eight consecutive weekly tests, testing may return to the monthly schedule. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. [District Rule 2201]

27. Compliance with the rolling 12-month average fuel sulfur content limit shall be demonstrated monthly. The 12-month rolling average fuel sulfur content shall be calculated as follows: 12-month rolling average fuel sulfur content = Sum of the monthly average fuel sulfur contents for the previous 12 months ÷ total number of months the unit has operated in during the previous 12 months. The monthly average fuel sulfur content is the average fuel sulfur content of all tests conducted in a given month. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. Owner/operator shall keep a monthly record of the rolling 12-month average fuel sulfur content. [District Rules 1081 and 2201]

28. 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. [District Rule 2201]

29. The exhaust stack shall either be equipped with a continuous emissions monitor (CEM) for NO_X, CO, and O_2 or the owner/operator shall implement one of the alternate monitoring schemes (A, B, C, D, E, F, or G) listed in District Rule 4320, Section 5.7.1 (dated 10/16/08). Owner/operator shall submit, in writing, the chosen method of monitoring (either CEMS or chosen alternate monitoring scheme) at least 30 days prior to initial operation of this boiler. [District Rules 2201, 4305, 4306 and 4320]

30. 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]

31. Owner/operator shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rule 2201 and 40 CFR 60.48 (c)(g)]

32. Owner/operator shall keep a record of the cumulative annual quantity of hours operated for this unit. The record shall be updated at least monthly. [District Rule 2201]

33. 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, 4306, and 4320]

N-4597-6-0: 288 BHP CUMMINS MODEL CFP83-F40 TIER 3 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIREWATER PUMP OR EQUIVALENT

1. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule]

2. Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

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

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

5. 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. The owner/operator shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

7. The owner/operator's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

8. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

9. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

10. 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]

11. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 40 CFR 60.4209(a)]

12. This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]

13. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [40 CFR 60.4211(a)]

14. Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801, 40 CFR 60.4207 and 17 CCR 93115]

15. Emissions from this IC engine shall not exceed any of the following limits: 2.67 g-NOx/bhp-hr, 2.39 g-CO/bhp-hr, or 0.16 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115 and 40 CFR 60.4205(c)]

16. Emissions from this IC engine shall not exceed 0.12 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 and 40 CFR 60.4205(c)]

17. 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 and 40 CFR 60.4211(e)]

18. The owner/operator 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, emergency firefighting, 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]

19. 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]

ATTACHMENT B

Permits to Operate N-4597-1-4, N-4597-2-4 and N-4597-4-1

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: N-4597-1-4 **EXPIRATION DATE:** 06/30/2009

EQUIPMENT DESCRIPTION:
84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST

PERMIT UNIT REQUIREMENTS

1. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. No air contaminants shall be discharged into the atmosphere for a period or periods aggregating more than 3 minutes in any one hour which is as dark or darker than Ringelmann #1 or equivalent to 20% opacity and greater, unless specifically exempted by District Rule 4101 (11/15/01). If the equipment or operation is subject to a more stringent visible emission standard as prescribed in a permit condition, the more stringent visible emission limit shall supersede this condition. [District Rule 4101, and County Rules 401 (in all eight counties in the San Joaquin Valley)] Federally Enforceable Through Title V Permit
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201, 3.1] Federally Enforceable Through Title V Permit
4. Sulfur compound emissions shall not exceed 0.2% by volume, 2,000 ppmv, on a dry basis averaged over 15 consecutive minutes. [40 CFR 60.333(a); County Rules 404 (Madera), 406 (Fresno), and 407 (Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus)] Federally Enforceable Through Title V Permit
5. This unit shall exclusively burn only natural gas with a sulfur content no greater than 0.25 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.333(a)] Federally Enforceable Through Title V Permit
6. Operation of this unit shall not exceed 8,000 hours per calendar year. [District Rule 2201] Federally Enforceable Through Title V Permit
7. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents no greater than 5% opacity, except for three minutes in any hour. [District Rule 2201] Federally Enforceable Through Title V Permit
8. A selective catalytic reduction (SCR) system and oxidation catalyst shall serve the gas turbine engine. Exhaust ducting shall be equipped with a fresh air inlet and blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. [District Rule 2201] Federally Enforceable Through Title V Permit
9. During a startup and a shutdown of a gas turbine engine, the emissions from the gas turbine engine shall not exceed the following: NOx (as NO2) - 26 pounds in any one hour and CO - 42 pounds in any one hour. [California Environmental Quality Act]
10. A startup event is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in Condition 15. A shutdown event is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. [District Rule 2201] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

11. The start up or shut down time, during which the exhaust gas is not within the normal operating temperature range, shall not exceed two hours. [District Rule 4703, 3.25] Federally Enforceable Through Title V Permit

12. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703] Federally Enforceable Through Title V Permit

13. Emissions from this unit, except during startup and shutdown events, shall not exceed any of the following: NOx (as NO2) - 26.45 lb/hr and 5.0 ppmvd @ 15% O2; VOC - 2.42 lb/hr and 2.0 ppmvd @ 15% O2; CO - 26.57 lb/hr and 6.0 ppmvd @ 15% O2; PM10 - 3.3 lb/hr; and SOx (as SO2) - 0.78 lb/hr. All emission concentration limits are three-hour rolling averages. [District Rules 2201 and 4703, 5.1 and 5.2 and 40 CFR 60.332(a)(1) and (a)(2)] Federally Enforceable Through Title V Permit

14. Emissions from this unit, including emissions from startup events and shutdown events, shall not exceed any of the following: NOx (as NO2) - 493.3 lb/day; VOC - 42.4 lb/day; CO - 235.7 lb/day; PM10 - 80.0 lb/day; and SOx (as SO2) - 18.7 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

15. Combined quarterly emissions from N-4597-1 and N-4597-2, including emissions from startup events and shutdown events, shall be calculated for each calendar quarter and shall not exceed any of the following: NOx (as NO2) - Q1: 76,704 lb, Q2: 76,704 lb, Q3: 76,756 lb, and Q4: 76,756 lb; VOC - Q1: 6,676 lb, Q2: 6,676 lb, Q3: 6,680 lb, and Q4: 6,680 lb; and PM10 - Q1: 13,333 lb, Q2: 13,333 lb, Q3: 13,333 lb, and Q4: 13,333 lb. [District Rule 2201] Federally Enforceable Through Title V Permit

16. Combined annual emissions from N-4597-1 and N-4597-2, including emissions from startup events and shutdown events, calculated on a twelve consecutive month rolling basis shall not exceed any of the following: NOx (as NO2) - 306,920 lb/year; VOC - 26,712 lb/year; and PM10 - 53,334 lb/year. [District Rule 2201] Federally Enforceable Through Title V Permit

17. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201] Federally Enforceable Through Title V Permit

18. Compliance with ammonia slip limit shall be demonstrated utilizing the following calculation procedure: ammonia slip ppmvd @ 15% O2 = ((a - (b x c/1,000,000)) x (1,000,000 / b) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOX concentration ppmvd @ 15% O2 across the catalyst and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, the permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District to monitor compliance. At least 60 days prior to using a NH3 CEM, the permittee shall submit a monitoring plan for District review and approval. [District Rule 4102]

19. 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. [District Rule 2201] Federally Enforceable Through Title V Permit

20. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Quarterly emissions shall be calculated for each calendar quarter in a year. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions total to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201] Federally Enforceable Through Title V Permit

21. Source testing to demonstrate compliance with the NOx, CO, and VOC short-term emission limits (lb/hr and ppmv @ 15% O2) shall be conducted at least once every twelve months. [District Rules 1081 and 4703] Federally Enforceable Through Title V Permit

22. Source testing to demonstrate compliance with PM10 short-term emission limit (lb/hr) shall be conducted at least once every twelve months. [District Rule 1081] Federally Enforceable Through Title V Permit

23. Source testing of startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbine engines (N-4597-1 or N-4597-2) at least once every seven years by District-witnessed, in-situ sampling of exhaust gases by a qualified independent source testing company. CEM relative accuracy shall be determined during startup source testing in accordance with District-approved protocol. [District Rule 1081] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

24. Source testing to demonstrate compliance with the NOx, CO, VOC, PM10, and NH3 requirements of this permit shall be conducted at least once every twelve months. [District Rules 2201 and 4703 and 40 CFR 60.332(a),(b)] Federally Enforceable Through Title V Permit
25. Compliance with the natural gas sulfur content limit shall be demonstrated periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 40 CFR 60.333(b)] Federally Enforceable Through Title V Permit
26. Testing to demonstrate compliance with the fuel sulfur content limit shall be conducted weekly. Once eight consecutive weekly tests show compliance, the fuel sulfur content testing frequency may be reduced to once every calendar quarter. If a quarterly test shows a violation of the sulfur content limit then weekly testing shall resume and continue until eight consecutive tests show compliance. Once compliance is shown on eight consecutive weekly tests then testing may return to quarterly. [40 CFR 60.334(h)(1)] Federally Enforceable Through Title V Permit
27. The following test methods shall be used: NOx - EPA Method 7E or 20; CO - EPA Method 10 or 10B; O2 - EPA Method 3, 3A, or 20; VOC - EPA Method 18 or 25; and NH3 - BAAQMD Method ST-1B. Alternative test methods, as approved by the District, may also be used to address the source testing requirements of this permit. [District Rules 1081, 2201 and 4703 and 40 CFR 60.335(b)] Federally Enforceable Through Title V Permit
28. Source testing to measure concentrations of PM10 shall be conducted using EPA methods 201 and 202, or EPA methods 201A and 202, or CARB method 501 in conjunction with CARB method 5. [District Rule 2201] Federally Enforceable Through Title V Permit
29. Testing for fuel sulfur content shall be conducted utilizing ASTM method D 3246. [District Rule 2201 and 40 CFR 60.335(d)] Federally Enforceable Through Title V Permit
30. The HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, OR ASTM 1945. [District Rule 4703 and 40 CFR 60.332(a),(b)] Federally Enforceable Through Title V Permit
31. The owner or operator shall be required to conform to the compliance testing and sampling procedures described in District Rule 1081 (as amended 12/16/93). [District Rule 1081] Federally Enforceable Through Title V Permit
32. 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 portable NOx, CO, NH3 and O2 monitoring equipment during District inspections. [District Rule 1081] Federally Enforceable Through Title V Permit
33. The exhaust stack shall be equipped with permanent provisions for stack gas sample collection. 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] Federally Enforceable Through Title V Permit
34. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. 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 of source testing. [District Rule 1081] Federally Enforceable Through Title V Permit
35. The owner or operator shall install, operate and maintain in calibration a system which continuously measures and records: emissions control system operating parameters, elapsed time of operation of the turbine, the fuel consumption being fired in the turbine, and the exhaust gas NOx and O2 concentrations. [District Rules 2201 and 4703 and 40 CFR 60.334(a) and 40 CFR Part 64] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

36. CTG exhaust shall be equipped with continuously recording emissions monitor(s) dedicated to this unit for NOx, CO, and O2. Continuous emissions monitor(s) (CEM) shall meet the requirements of 40 CFR part 60, Appendices B and F, and 40 CFR part 75, and District-approved protocol, and shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided the CEM(s) pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEM(s) cannot be demonstrated during startup conditions, CEM 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, 2201 and 4703; and 40 CFR 60.334(c), 40 CFR Part 64 and 40 CFR Part 72] Federally Enforceable Through Title V Permit

37. The NOx and O2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specifications 2 and 3, or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.334(b)(1)] Federally Enforceable Through Title V Permit

38. 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 60.334(b)(2)] Federally Enforceable Through Title V Permit

39. Results of the CEM system shall be averaged over a three hour period for NOx and CO emissions using consecutive 15-minute sampling periods in accordance with either EPA Method 7E or EPA Method 20 for NOx, EPA Methods 10 or 10B for CO, or EPA Methods 3, 3A, or 20 for O2, or, if continuous emission monitors are used, all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13] Federally Enforceable Through Title V Permit

40. 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 and 40 CFR Part 64] Federally Enforceable Through Title V Permit

41. 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 and 40 CFR 64] Federally Enforceable Through Title V Permit

42. 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] Federally Enforceable Through Title V Permit

43. 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] Federally Enforceable Through Title V Permit

44. 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] Federally Enforceable Through Title V Permit

45. 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] Federally Enforceable Through Title V Permit

46. The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703 and 40 CFR Part 64] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

47. 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 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 60.334(j), (j)(5)] Federally Enforceable Through Title V Permit

48. Excess emissions shall be defined as any operating hour in which 4-hour rolling average NOx 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 NOx or O2 (or both). [40 CFR 60.334(J)(1)(iii)] Federally Enforceable Through Title V Permit

49. 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] Federally Enforceable Through Title V Permit

50. Permittee shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmv @ 15% O2), and hourly, daily, and annual records of NOx and CO emissions. [District Rule 2201 and 40 CFR Part 64] Federally Enforceable Through Title V Permit

51. Permittee shall maintain records of SOx emissions rates in lb/hr and lb/day. SOx emission rates shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District Rule 2201] Federally Enforceable Through Title V Permit

52. The operator shall submit a semiannual report listing any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.25 grain of sulfur (as S) per 100 dry scf of natural gas. [District Rule 2520, 9.3.2 and 40 CFR 60.334(c)(2)] Federally Enforceable Through Title V Permit

53. Permittee shall maintain the following records for the CTG: actual turbine start-up and stop times (local time), length and reason for reduced load periods, occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 and 4703 and 40 CFR 60.7(b)] Federally Enforceable Through Title V Permit

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, 2201 and 4703 and 40 CFR 60.8(d)] Federally Enforceable Through Title V Permit

55. 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 1070 and 4703] Federally Enforceable Through Title V Permit

56. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following subsumed requirements: Rules 404 (Madera), 406 (Fresno), and 407 (Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus) as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

57. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following applicable requirements: 40 CFR 60.332(a), (a)(1), (a)(2), (b), and (f), 60.333 (a) and (b); 60.334(a), (b)(2), (c)(1), (c)(2), and (c)(3), and 60.335(b), (c)(2), (c)(3), and (d); District Rule 4703 (as amended 4/25/02), Sections 5.1.1, 5.2, 6.1, 6.3.1, 6.3.3, 6.4, 6.4.5, and 6.4.6 as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

58. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following applicable requirements: 40 CFR 60.7(b), 60.8, 60.8(d), 60.13, and 60.13(b); District Rules 1080 (as amended 12/17/92), Sections 6.3, 6.4, 6.5, 7.0, 7.1, 7.2, 7.3, 8.0, 9.0, 10.0, and 11.0; and 1081 (as amended 12/16/93) as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

59. The owners and operators of each affected source and each affected unit at the source shall: (i) Operate the unit in compliance with a complete Acid Rain permit application or a superceding Acid Rain permit issued by the permitting authority; and (ii) have an Acid Rain permit. [40 CFR 72] Federally Enforceable Through Title V Permit

60. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75] Federally Enforceable Through Title V Permit

61. The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75] Federally Enforceable Through Title V Permit

62. The owners and operators of each source and each affected unit at the source shall: (i) hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73] Federally Enforceable Through Title V Permit

63. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77] Federally Enforceable Through Title V Permit

64. An affected unit shall be subject to the sulfur dioxide requirements starting on the later of January 1, 2000, or the deadline for monitoring certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3) that is not a substitution or compensating unit. [40 CFR 72, 40 CFR 75] Federally Enforceable Through Title V Permit

65. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72] Federally Enforceable Through Title V Permit

66. An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73] Federally Enforceable Through Title V Permit

67. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72] Federally Enforceable Through Title V Permit

68. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72] Federally Enforceable Through Title V Permit

69. The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides. [40 CFR 72] Federally Enforceable Through Title V Permit

70. The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77] Federally Enforceable Through Title V Permit

71. The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

72. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72] Federally Enforceable Through Title V Permit

73. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 72, 40 CFR 75] Federally Enforceable Through Title V Permit

74. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75] Federally Enforceable Through Title V Permit

PERMIT UNIT: N-4597-2-4 **EXPIRATION DATE:** 06/30/2009

EQUIPMENT DESCRIPTION:
84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST

PERMIT UNIT REQUIREMENTS

1. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. No air contaminants shall be discharged into the atmosphere for a period or periods aggregating more than 3 minutes in any one hour which is as dark or darker than Ringelmann #1 or equivalent to 20% opacity and greater, unless specifically exempted by District Rule 4101 (11/15/01). If the equipment or operation is subject to a more stringent visible emission standard as prescribed in a permit condition, the more stringent visible emission limit shall supersede this condition. [District Rule 4101, and County Rules 401 (in all eight counties in the San Joaquin Valley)] Federally Enforceable Through Title V Permit
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201, 3.1] Federally Enforceable Through Title V Permit
4. Sulfur compound emissions shall not exceed 0.2% by volume, 2,000 ppmv, on a dry basis averaged over 15 consecutive minutes. [40 CFR 60.333(a); County Rules 404 (Madera), 406 (Fresno), and 407 (Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus)] Federally Enforceable Through Title V Permit
5. This unit shall exclusively burn only natural gas with a sulfur content no greater than 0.25 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.333(a)] Federally Enforceable Through Title V Permit
6. Operation of this unit shall not exceed 8,000 hours per calendar year. [District Rule 2201] Federally Enforceable Through Title V Permit
7. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents no greater than 5% opacity, except for three minutes in any hour. [District Rule 2201] Federally Enforceable Through Title V Permit
8. A selective catalytic reduction (SCR) system and oxidation catalyst shall serve the gas turbine engine. Exhaust ducting shall be equipped with a fresh air inlet and blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. [District Rule 2201] Federally Enforceable Through Title V Permit
9. During a startup and a shutdown of a gas turbine engine, the emissions from the gas turbine engine shall not exceed the following: NOx (as NO2) - 26 pounds in any one hour and CO - 42 pounds in any one hour. [California Environmental Quality Act]
10. A startup event is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in Condition 15. A shutdown event is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. [District Rule 2201] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

11. The start up or shut down time, during which the exhaust gas is not within the normal operating temperature range, shall not exceed two hours. [District Rule 4703, 3.25] Federally Enforceable Through Title V Permit

12. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703] Federally Enforceable Through Title V Permit

13. Emissions from this unit, except during startup and shutdown events, shall not exceed any of the following: NOx (as NO2) - 26.45 lb/hr and 5.0 ppmvd @ 15% O2; VOC - 2.42 lb/hr and 2.0 ppmvd @ 15% O2; CO - 26.57 lb/hr and 6.0 ppmvd @ 15% O2; PM10 - 3.3 lb/hr; and SOx (as SO2) - 0.78 lb/hr. All emission concentration limits are three-hour rolling averages. [District Rules 2201 and 4703, 5.1 and 5.2 and 40 CFR 60.332(a)(1) and (a)(2)] Federally Enforceable Through Title V Permit

14. Emissions from this unit, including emissions from startup events and shutdown events, shall not exceed any of the following: NOx (as NO2) - 493.3 lb/day; VOC - 42.4 lb/day; CO - 235.7 lb/day; PM10 - 80.0 lb/day; and SOx (as SO2) - 18.7 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

15. Combined quarterly emissions from N-4597-1 and N-4597-2, including emissions from startup events and shutdown events, shall be calculated for each calendar quarter and shall not exceed any of the following: NOx (as NO2) - Q1: 76,704 lb, Q2: 76,704 lb, Q3: 76,756 lb, and Q4: 76,756 lb; VOC - Q1: 6,676 lb, Q2: 6,676 lb, Q3: 6,680 lb, and Q4: 6,680 lb; and PM10 - Q1: 13,333 lb, Q2: 13,333 lb, Q3: 13,333 lb, and Q4: 13,333 lb. [District Rule 2201] Federally Enforceable Through Title V Permit

16. Combined annual emissions from N-4597-1 and N-4597-2, including emissions from startup events and shutdown events, calculated on a twelve consecutive month rolling basis shall not exceed any of the following: NOx (as NO2) - 306,920 lb/year; VOC - 26,712 lb/year; and PM10 - 53,334 lb/year. [District Rule 2201] Federally Enforceable Through Title V Permit

17. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201] Federally Enforceable Through Title V Permit

18. Compliance with ammonia slip limit shall be demonstrated utilizing the following calculation procedure: ammonia slip ppmvd @ 15% O2 = ((a - (b x c/1,000,000)) x (1,000,000 / b) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOX concentration ppmvd @ 15% O2 across the catalyst and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, the permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District to monitor compliance. At least 60 days prior to using a NH3 CEM, the permittee shall submit a monitoring plan for District review and approval. [District Rule 4102]

19. 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. [District Rule 2201] Federally Enforceable Through Title V Permit

20. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Quarterly emissions shall be calculated for each calendar quarter in a year. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions total to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201] Federally Enforceable Through Title V Permit

21. Source testing to demonstrate compliance with the NOx, CO, and VOC short-term emission limits (lb/hr and ppmv @ 15% O2) shall be conducted at least once every twelve months. [District Rules 1081 and 4703] Federally Enforceable Through Title V Permit

22. Source testing to demonstrate compliance with PM10 short-term emission limit (lb/hr) shall be conducted at least once every twelve months. [District Rule 1081] Federally Enforceable Through Title V Permit

23. Source testing of startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbine engines (N-4597-1 or N-4597-2) at least once every seven years by District-witnessed, in-situ sampling of exhaust gases by a qualified independent source testing company. CEM relative accuracy shall be determined during startup source testing in accordance with District-approved protocol. [District Rule 1081] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

24. Source testing to demonstrate compliance with the NOx, CO, VOC, PM10, and NH3 requirements of this permit shall be conducted at least once every twelve months. [District Rules 2201 and 4703 and 40 CFR 60.332(a),(b)] Federally Enforceable Through Title V Permit
25. Compliance with the natural gas sulfur content limit shall be demonstrated periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 40 CFR 60.333(b)] Federally Enforceable Through Title V Permit
26. Testing to demonstrate compliance with the fuel sulfur content limit shall be conducted weekly. Once eight consecutive weekly tests show compliance, the fuel sulfur content testing frequency may be reduced to once every calendar quarter. If a quarterly test shows a violation of the sulfur content limit then weekly testing shall resume and continue until eight consecutive tests show compliance. Once compliance is shown on eight consecutive weekly tests then testing may return to quarterly. [40 CFR 60.334(h)(1)] Federally Enforceable Through Title V Permit
27. The following test methods shall be used: NOx - EPA Method 7E or 20; CO - EPA Method 10 or 10B; O2 - EPA Method 3, 3A, or 20; VOC - EPA Method 18 or 25; and NH3 - BAAQMD Method ST-1B. Alternative test methods, as approved by the District, may also be used to address the source testing requirements of this permit. [District Rules 1081, 2201 and 4703 and 40 CFR 60.335(b)] Federally Enforceable Through Title V Permit
28. Source testing to measure concentrations of PM10 shall be conducted using EPA methods 201 and 202, or EPA methods 201A and 202, or CARB method 501 in conjunction with CARB method 5. [District Rule 2201] Federally Enforceable Through Title V Permit
29. Testing for fuel sulfur content shall be conducted utilizing ASTM method D 3246. [District Rule 2201 and 40 CFR 60.335(d)] Federally Enforceable Through Title V Permit
30. The HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, OR ASTM 1945. [District Rule 4703 and 40 CFR 60.332(a),(b)] Federally Enforceable Through Title V Permit
31. The owner or operator shall be required to conform to the compliance testing and sampling procedures described in District Rule 1081 (as amended 12/16/93). [District Rule 1081] Federally Enforceable Through Title V Permit
32. 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 portable NOx, CO, NH3 and O2 monitoring equipment during District inspections. [District Rule 1081] Federally Enforceable Through Title V Permit
33. The exhaust stack shall be equipped with permanent provisions for stack gas sample collection. 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] Federally Enforceable Through Title V Permit
34. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. 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 of source testing. [District Rule 1081] Federally Enforceable Through Title V Permit
35. The owner or operator shall install, operate and maintain in calibration a system which continuously measures and records: emissions control system operating parameters, elapsed time of operation of the turbine, the fuel consumption being fired in the turbine, and the exhaust gas NOx and O2 concentrations. [District Rules 2201 and 4703 and 40 CFR 60.334(a) and 40 CFR Part 64] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

36. CTG exhaust shall be equipped with continuously recording emissions monitor(s) dedicated to this unit for NOx, CO, and O2. Continuous emissions monitor(s) (CEM) shall meet the requirements of 40 CFR part 60, Appendices B and F, and 40 CFR part 75, and District-approved protocol, and shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided the CEM(s) pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEM(s) cannot be demonstrated during startup conditions, CEM 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, 2201 and 4703; and 40 CFR 60.334(c), 40 CFR Part 64 and 40 CFR Part 72] Federally Enforceable Through Title V Permit

37. The NOx and O2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specifications 2 and 3, or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.334(b)(1)] Federally Enforceable Through Title V Permit

38. 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 60.334(b)(2)] Federally Enforceable Through Title V Permit

39. Results of the CEM system shall be averaged over a three hour period for NOx and CO emissions using consecutive 15-minute sampling periods in accordance with either EPA Method 7E or EPA Method 20 for NOx, EPA Methods 10 or 10B for CO, or EPA Methods 3, 3A, or 20 for O2, or, if continuous emission monitors are used, all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13] Federally Enforceable Through Title V Permit

40. 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 and 40 CFR Part 64] Federally Enforceable Through Title V Permit

41. 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 and 40 CFR 64] Federally Enforceable Through Title V Permit

42. 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] Federally Enforceable Through Title V Permit

43. 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] Federally Enforceable Through Title V Permit

44. 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] Federally Enforceable Through Title V Permit

45. 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] Federally Enforceable Through Title V Permit

46. The permittee shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703 and 40 CFR Part 64] Federally Enforceable Through Title V Permit

47. 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 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 60.334(j), (j)(5)] Federally Enforceable Through Title V Permit

48. Excess emissions shall be defined as any operating hour in which 4-hour rolling average NOx 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 NOx or O2 (or both). [40 CFR 60.334(J)(1)(iii)] Federally Enforceable Through Title V Permit

49. 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] Federally Enforceable Through Title V Permit

50. Permittee shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmv @ 15% O2), and hourly, daily, and annual records of NOx and CO emissions. [District Rule 2201 and 40 CFR Part 64] Federally Enforceable Through Title V Permit

51. Permittee shall maintain records of SOx emissions rates in lb/hr and lb/day. SOx emission rates shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District Rule 2201] Federally Enforceable Through Title V Permit

52. The operator shall submit a semiannual report listing any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.25 grain of sulfur (as S) per 100 dry scf of natural gas. [District Rule 2520, 9.3.2 and 40 CFR 60.334(c)(2)] Federally Enforceable Through Title V Permit

53. Permittee shall maintain the following records for the CTG: actual turbine start-up and stop times (local time), length and reason for reduced load periods, occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 and 4703 and 40 CFR 60.7(b)] Federally Enforceable Through Title V Permit

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, 2201 and 4703 and 40 CFR 60.8(d)] Federally Enforceable Through Title V Permit

55. 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 1070 and 4703] Federally Enforceable Through Title V Permit

56. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following subsumed requirements: Rules 404 (Madera), 406 (Fresno), and 407 (Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus) as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

57. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following applicable requirements: 40 CFR 60.332(a), (a)(1), (a)(2), (b), and (f), 60.333 (a) and (b); 60.334(a), (b)(2), (c)(1), (c)(2), and (c)(3), and 60.335(b), (c)(2), (c)(3), and (d); District Rule 4703 (as amended 4/25/02), Sections 5.1.1, 5.2, 6.1, 6.3.1, 6.3.3, 6.4, 6.4.5, and 6.4.6 as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

58. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following applicable requirements: 40 CFR 60.7(b), 60.8, 60.8(d), 60.13, and 60.13(b); District Rules 1080 (as amended 12/17/92), Sections 6.3, 6.4, 6.5, 7.0, 7.1, 7.2, 7.3, 8.0, 9.0, 10.0, and 11.0; and 1081 (as amended 12/16/93) as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

59. The owners and operators of each affected source and each affected unit at the source shall: (i) Operate the unit in compliance with a complete Acid Rain permit application or a superceding Acid Rain permit issued by the permitting authority; and (ii) have an Acid Rain permit. [40 CFR 72] Federally Enforceable Through Title V Permit

60. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75] Federally Enforceable Through Title V Permit

61. The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75] Federally Enforceable Through Title V Permit

62. The owners and operators of each source and each affected unit at the source shall: (i) hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73] Federally Enforceable Through Title V Permit

63. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77] Federally Enforceable Through Title V Permit

64. An affected unit shall be subject to the sulfur dioxide requirements starting on the later of January 1, 2000, or the deadline for monitoring certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3) that is not a substitution or compensating unit. [40 CFR 72, 40 CFR 75] Federally Enforceable Through Title V Permit

65. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72] Federally Enforceable Through Title V Permit

66. An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73] Federally Enforceable Through Title V Permit

67. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72] Federally Enforceable Through Title V Permit

68. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72] Federally Enforceable Through Title V Permit

69. The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides. [40 CFR 72] Federally Enforceable Through Title V Permit

70. The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77] Federally Enforceable Through Title V Permit

71. The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

72. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72] Federally Enforceable Through Title V Permit

73. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 72, 40 CFR 75] Federally Enforceable Through Title V Permit

74. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: N-4597-4-1 **EXPIRATION DATE:** 06/30/2009

EQUIPMENT DESCRIPTION:
471 HP CATERPILLAR MODEL 3456 DI TA AA DIESEL-FIRED EMERGENCY IC ENGINE POWERING A 300 KW ELECTRICAL GENERATOR

PERMIT UNIT REQUIREMENTS

1. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201, 3.1] Federally Enforceable Through Title V Permit
2. The engine shall be equipped with a positive crankcase ventilation (PCV) system or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201] Federally Enforceable Through Title V Permit
3. This engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 200 hours per year. [District Rules 2201 and 4701, 4.2.1] Federally Enforceable Through Title V Permit
4. The exhaust stack(s) shall not be fitted with a fixed rain cap or any similar device that would impede upward vertical exhaust flow during operation. [District Rule 4102] Federally Enforceable Through Title V Permit
5. NOx emissions shall not exceed 4.69 g/hp-hr. [District Rule 2201] Federally Enforceable Through Title V Permit
6. CO emissions shall not exceed 0.12 g/hp-hr. [District Rule 2201] Federally Enforceable Through Title V Permit
7. VOC emissions shall not exceed 0.04 g/hp-hr. [District Rule 2201] Federally Enforceable Through Title V Permit
8. PM10 emissions shall not exceed 0.029 g/bhp-hr based on U.S EPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit
9. Only CARB-certified diesel fuel containing not more than 0.05% sulfur by weight shall be used. [San Joaquin County Rule 407, District Rules 2201, 4102, and 4801] Federally Enforceable Through Title V Permit
10. The permittee shall maintain records of hours of emergency and non-emergency operation. Records shall include the date, the number of hours of operation, the purpose of the operation (e.g., load testing, weekly testing, rolling blackout, general area power outage, etc.), and the sulfur content of the diesel fuel used. Such records shall be retained on-site and made available for District inspection upon request. [District Rules 2201 and 4701, 6.] Federally Enforceable Through Title V Permit

ATTACHMENT C

Project Location and Site Plan

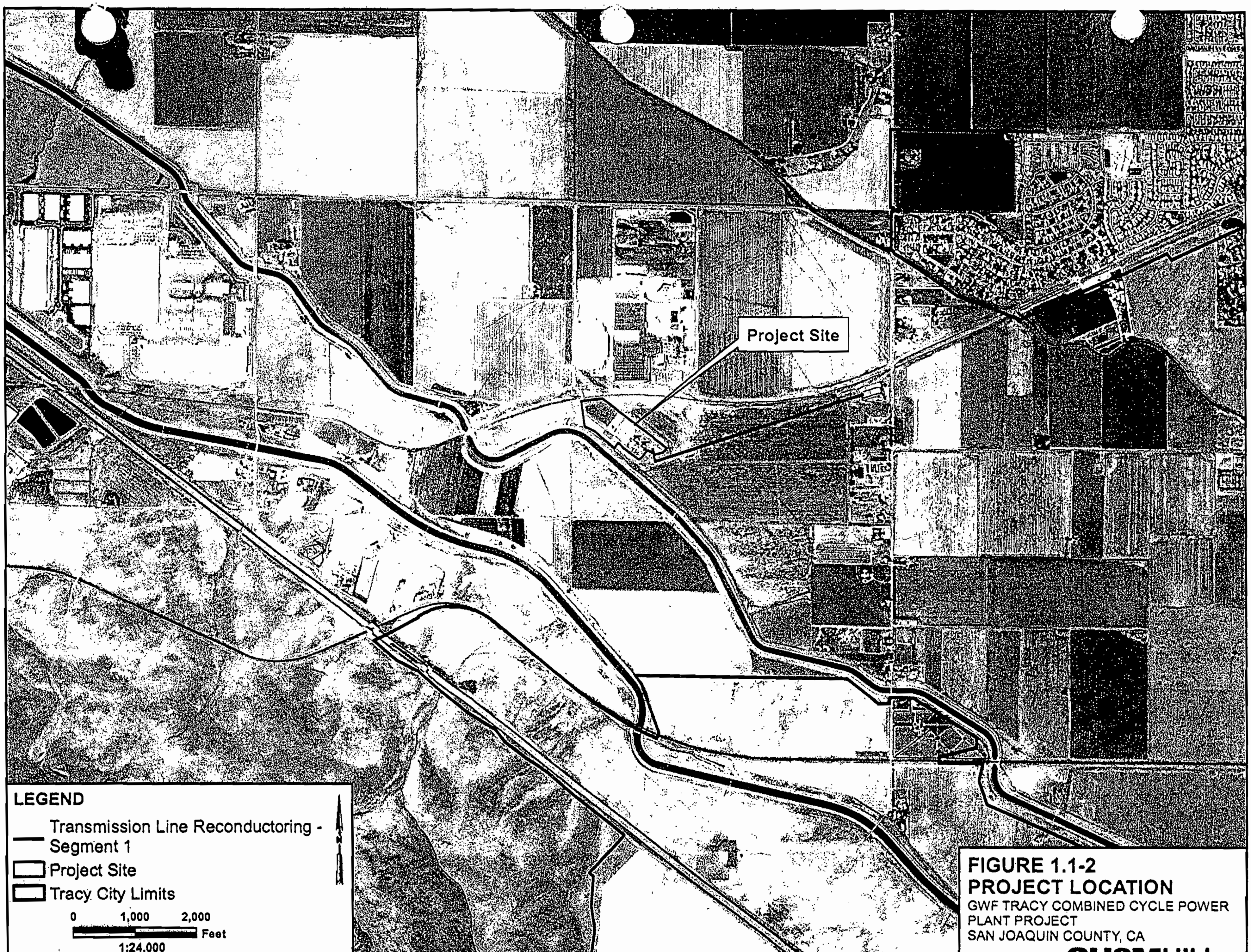


FIGURE 1.1-2
PROJECT LOCATION
GWF TRACY COMBINED CYCLE POWER PLANT PROJECT
SAN JOAQUIN COUNTY, CA

CH2MHILL

SAC \\ZION\SACGIS\PROJ\365887_GWF_TRACY\MAPFILES\PROJECT_SITE.MXD 8/25/2008 17:33:48

EQUIPMENT LIST	
ITEM NO.	DESCRIPTION
1	INLET AIR FILTER EXISTING
2	ACCESSORY COMPARTMENT EXISTING
3	COMBUSTION TURBINE 7EA EXISTING
4	EXHAUST PLENUM EXISTING
5	GENERATOR EXISTING
6	SWITCHGEAR COMPARTMENT EXISTING
7	LUBE OIL DEMISTER EXISTING
8	GAS VALVE MODULE EXISTING
9	NOT USED
10	NOT USED
11	EXHAUST FRAME BLOWERS EXISTING
12	CO2 FIRE PROTECTION SKID EXISTING
13	WATER WASH DRAINS TANK (UNDERGROUND) EXISTING
14	WATER WASH SKID EXISTING
15	PEECC EXISTING
16	NOT USED
17	AIR PROCESSING UNIT EXISTING
18	FUEL GAS SCRUBBER EXISTING
19	FUEL GAS SCRUBBER DRAINS TANK EXISTING
20	COOLING WATER MODULE EXISTING

EQUIPMENT LIST	
ITEM NO.	DESCRIPTION
21	NOT USED
22	FUEL GAS HEATER SKID EXISTING
23	GSU TRANSFORMER EXISTING
24	GWF SWITCHYARD EXISTING
25	OIL/WATER SEPARATOR (UNDERGROUND) EXISTING
26	AQUEOUS AMMONIA STORAGE TANK EXISTING
27	AQUEOUS AMMONIA FORWARDING PUMPS EXISTING
28	NOT USED
29	WASTE WATER STORAGE TANK (UNDERGROUND) EXISTING
30	CRANKING MOTOR STARTER TRANSFORMER/SWITCHGEAR EXISTING
31	GAS METERING STATION (BY OWNER) EXISTING
32	SPILL CONTAINMENT STORAGE TANK (UNDERGROUND) EXISTING
33	PIPE TRENCH EXISTING
34	UNIT 1 AUXILIARY TRANSFORMER EXISTING
35	UNIT 2 AUXILIARY TRANSFORMER EXISTING
36	SWITCHGEAR EXISTING
37	RAW WATER FORWARDING PUMPS EXISTING
38	EVAPORATIVE COOLER BLOWDOWN TANK EXISTING
39	EVAPORATIVE COOLER BLOWDOWN FORWARDING PUMPS EXISTING
40	ADMIN/MAINTENANCE BUILDING EXISTING

EQUIPMENT LIST	
ITEM NO.	DESCRIPTION
41	POTABLE WATER TREATMENT SKID EXISTING
42	SERVICE/FIRE WATER STORAGE TANK EXISTING
43	SERVICE WATER FORWARDING PUMPS EXISTING
44	FIRE PROTECTION PUMPS REWORKED
45	EMERGENCY DIESEL GENERATOR EXISTING
46	RAW WATER TREATMENT SKID EXISTING
47	AIR COMPRESSORS EXISTING
48	AIR DRYERS EXISTING
49	LONG TERM MIXING BEDS EXISTING
50	DEMIN BOTTLE EXISTING
51	AIR RECEIVER EXISTING
52	SUBSTATION EXISTING
53	RETENTION BASIN RELOCATED
54	SEPTIC TANK FIELD EXISTING
55	GWF SWITCHYARD CONTROL BUILDING EXISTING
101	HRSG
102	HRSG STACK
103	BOILER FEED PUMPS
104	BOILER BLOWDOWN TANK
105	CEM EQUIPMENT/ENCLOSURE

EQUIPMENT LIST	
ITEM NO.	DESCRIPTION
106	SCR SKID
107	DUCT BURNER SKID
108	STEAM TURBINE
109	STEAM TURBINE GENERATOR
110	GENERATOR ROTOR REMOVAL
111	ST LUBE OIL RESERVOIR
112	GLAND CONDENSER
113	ST STEP-UP TRANSFORMER
114	ST AUXILIARY TRANSFORMER
115	ST GENERATOR BREAKER
116	ST GENERATOR EXCITATION COMPARTMENT
117	ST ISOLATED PHASE BUS DUCT
118	NON-SEGREGATED BUS DUCT
119	MEDIUM VOLTAGE SWITCHGEAR
120	SECONDARY UNIT SUBSTATION
121	PIPE RACK
122	WATER TREATMENT
123	DEMINERALIZED WATER TANK
124	STEAM DUCT
125	AIR COOLED CONDENSER
126	AUXILIARY BOILER & STACK
127	D.I. TRAILERS
128	MAINTENANCE PARKING
129	SERVICE/FIRE WATER STORAGE TANK
130	FIRE WATER STORAGE TANK
131	S.T.CLOSED CYCLE COOLING UNIT

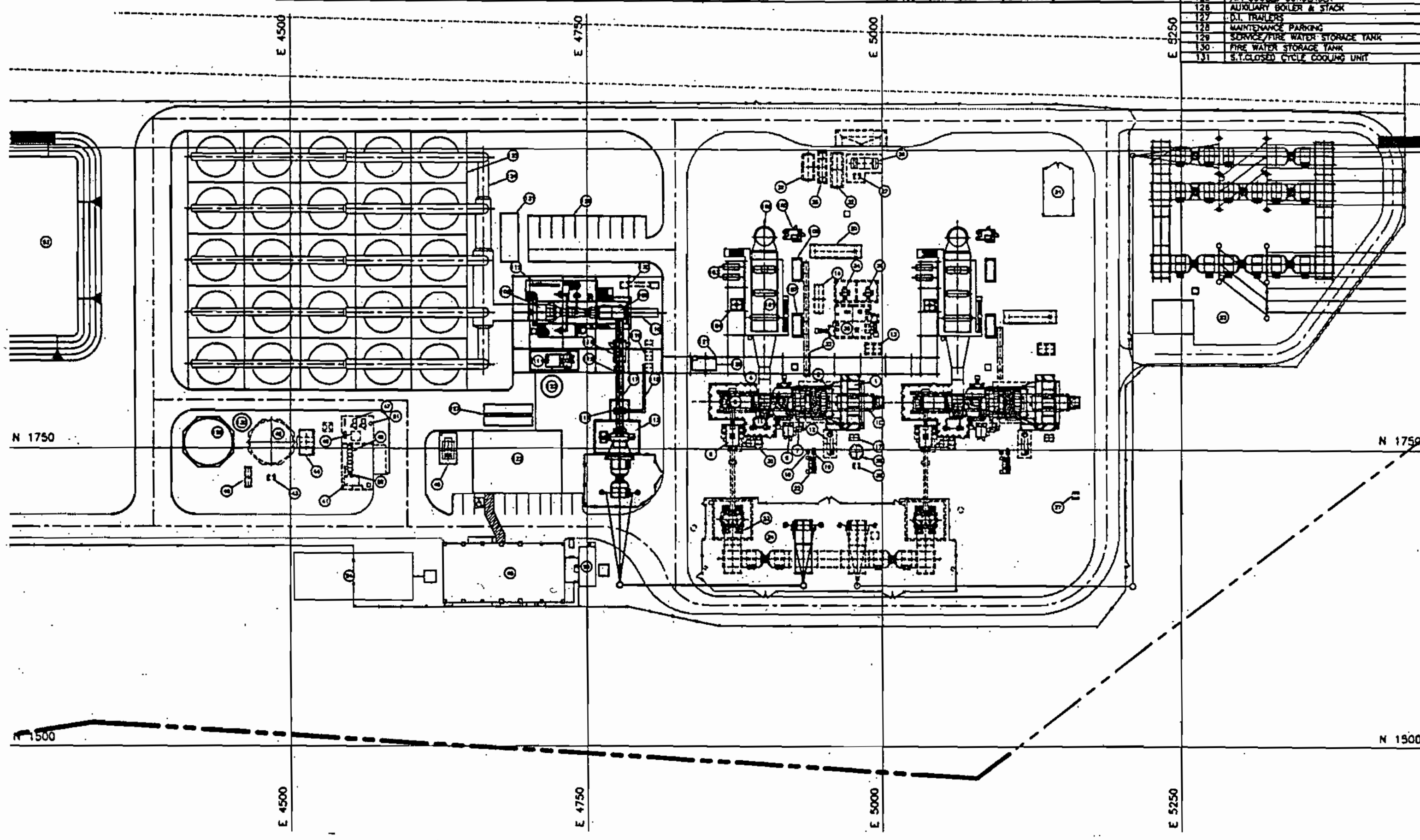


Figure source: Black & Veatch Corporation, Drawing #160129-DM-M1001

NOT TO BE USED
FOR CONSTRUCTION

FIGURE 2.1-1
DETAILED SITE LAYOUT
GWF TRACY COMBINED CYCLE
POWER PLANT PROJECT
SAN JOAQUIN COUNTY, CA

CH2MHILL

ES032008006SAC Figure_2.1-1.ai 7/10/2008 tdaun

ATTACHMENT D

CTG Commissioning Period Emissions Data

GWF Tracy Combined Cycle Power Plant Project (08-AFC-7)
Data Response Set #1
Attachment DR4-1

CTG 1			CTG 2			Total Emissions Lb/Day		Total Emissions Lb/Hr	
Activity	Duration [hr](1)	Modeling Load (%)	Activity	Duration [hr](1)	Modeling Load (%)	Nox	CO	Nox	CO
CTG 1 Testing (Full Speed No Load, FSNL)	8	50	No Operation	0	0	416.6	592.9	52.1	74.1
No Operation	0	NA	CTG 2 Testing (Full Speed No Load, FSNL)	8	50	416.6	592.9	52.1	74.1
Steam Blows	12	50	No Operation	0		919.4	1918.4	76.6	159.9
Steam Blows	12	50	No Operation	0		852.9	1804.9	71.1	150.4
No Operation	0	NA	Steam Blows	12	50	919.4	1918.4	76.6	159.9
No Operation	0	NA	Steam Blows	12	50	852.9	1804.9	71.1	150.4
Steam Blows	12	50	Steam Blows	12	50	1705.8	3609.8	142.2	300.8
Restart CTGs and run HRSG in Bypass Mode Bypass Valve Tuning. HRSG Blow Down and Drum Tuning	12	50	No Operation	0	0	1760.7	2755.7	146.7	229.6
Restart CTGs and run HRSG in Bypass Mode Bypass Valve Tuning. HRSG Blow Down and Drum Tuning	12	50	No Operation	0	0	1648.7	1750.8	137.4	145.9
Restart CTGs and run HRSG in Bypass Mode Bypass Valve Tuning. HRSG Blow Down and Drum Tuning	12	100	No Operation	0	0	437.0	744.0	36.4	62.0
No Operation	0	0	Restart CTGs and run HRSG in Bypass Mode Bypass Valve Tuning. HRSG Blow Down and Drum Tuning	12	50	1760.7	2755.7	146.7	229.6
No Operation	0	0	Restart CTGs and run HRSG in Bypass Mode Bypass Valve Tuning. HRSG Blow Down and Drum Tuning	12	50	1648.7	1750.8	137.4	145.9
No Operation	0	0	Restart CTGs and run HRSG in Bypass Mode Bypass Valve Tuning. HRSG Blow Down and Drum Tuning	12	100	437.0	744.0	36.4	62.0
Verify STG on Turning Gear; Establish Vacuum in ACC Ext Bypass Blowdown to ACC (combined blows) commence tuning on ACC Controls; Finalize Bypass Valve Tuning	12	50	Verify STG on Turning Gear; Establish Vacuum in ACC Ext Bypass Blowdown to ACC (combined blows) commence tuning on ACC Controls; Finalize Bypass Valve Tuning	12	50	3297.4	3501.6	274.8	291.8
Verify STG on Turning Gear; Establish Vacuum in ACC Ext Bypass Blowdown to ACC (combined blows) commence tuning on ACC Controls; Finalize Bypass Valve Tuning	12	100	Verify STG on Turning Gear; Establish Vacuum in ACC Ext Bypass Blowdown to ACC (combined blows) commence tuning on ACC Controls; Finalize Bypass Valve Tuning	12	100	874.0	1488.0	72.8	124.0
CT Tuner After Liner Change	12	100	No Operation	0	0	549.0	270.3	45.8	22.5
CTG 1 Base Load / Commissioning of Ammonia system	12	100	No Operation	0	0	245.0	173.8	20.4	14.5
Pre-STG Roll Outage and Stack Emissions Test Equipment Installation	0	0	CT Tuner After Liner Change	12	100	549.0	270.3	45.8	22.5
Pre-STG Roll Outage and Stack Emissions Test Equipment Installation	0	0	CT 2 Base Load/Commissioning Ammonia	12	100	245.0	173.8	20.4	14.5
STG Load Test	24	50	No Operation	0	0	709.2	397.2	29.6	16.5
Load Test STG / Combine Cycle (2X1)	24	100	Load Test STG / Combine Cycle (2X1)	24	100	1748.4	1179.3	72.9	49.1
Load Test STG / Combine Cycle (2X1)	24	100	Load Test STG / Combine Cycle (2X1)	24	100	1418.4	794.3	59.1	33.1
Load Test STG / Combine Cycle (2X1)	24	100	Load Test STG / Combine Cycle (2X1)	24	100	345.6	259.2	14.4	10.8
Combine Cycle testing	24	100	Combine Cycle testing	24	100	345.6	259.2	14.4	10.8
No Operation	0	0	STG Load Test	24	100	709.2	397.2	29.6	16.5
Commissioning Duct Burners	24	100 + DB	Commissioning Duct Burners	24	100 + DB	460.8	417.6	19.2	17.4
Emissions Tuning	12	100	No Operation	0	0	251.4	257.3	21.0	21.4
Emissions Tuning	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
RATA / Pre-performance Testing/Source Testing	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7

GWF Tracy Combined Cycle Power Plant Project (08-AFC-7)

Data Response Set #1

Attachment DR4-1

CTG 1			CTG 2			Total Emissions Lb/Day		Total Emissions Lb/Hr	
Activity	Duration [hr](1)	Modeling Load (%)	Activity	Duration [hr](1)	Modeling Load (%)	Nox	CO	Nox	CO
RATA / Pre-performance Testing/Source Testing	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
RATA / Pre-performance Testing/Source Testing	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
RATA / Pre-performance Testing/Source Testing	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
RATA / Pre-performance Testing/Source Testing	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
Source Testing & Drift Test Day 1	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
Source Testing & Drift Test Day 2	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
Source Testing & Drift Test Day 3	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
Source Testing & Drift Test Day 4	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
Source Testing & Drift Test Day 5	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
Source Testing & Drift Test Day 6	12	100 + DB	No Operation	0	0	168.2	200.4	14.0	16.7
No Operation	0	0	Emissions Tuning	12	100	251.4	257.3	21.0	21.4
No Operation	0	0	Emissions Tuning	12	100 + DB	168.2	200.4	14.0	16.7
No Operation	0	0	RATA / Pre-performance Testing/Source Testing	12	100 + DB	168.2	200.4	14.0	16.7
No Operation	0	0	RATA / Pre-performance Testing/Source Testing	12	100 + DB	168.2	200.4	14.0	16.7
No Operation	0	0	RATA / Pre-performance Testing/Source Testing	12	100 + DB	168.2	200.4	14.0	16.7
No Operation	0	0	RATA / Pre-performance Testing/Source Testing	12	100 + DB	168.2	200.4	14.0	16.7
No Operation	0	0	RATA / Pre-performance Testing/Source Testing	12	100 + DB	168.2	200.4	14.0	16.7
No Operation	0	0	RATA/Pre-perform Testing/Source Testing/Drift Testing	12	100 + DB	168.2	200.4	14.0	16.7
No Operation & Performance Test Preparations	0	0	RATA/Pre-perform Testing/Source Testing/Drift Testing	12	100 + DB	168.2	200.4	14.0	16.7
No Operation & Performance Test Preparations	0	0	RATA/Pre-perform Testing/Source Testing/Drift Testing	12	100 + DB	168.2	200.4	14.0	16.7
No Operation & Performance Test Preparations	0	0	RATA/Pre-perform Testing/Source Testing/Drift Testing	12	100 + DB	168.2	200.4	14.0	16.7
No Operation & Performance Test Preparations	0	0	Source Testing & Drift Test Day 1	12	100 + DB	168.2	200.4	14.0	16.7
No Operation & Performance Test Preparations	0	0	Source Testing & Drift Test Day 2	12	100 + DB	168.2	200.4	14.0	16.7
Performance Testing	24	100	Performance Testing	24	100	451.6	451.2	18.8	18.8
Performance Testing	24	100 + DB	Performance Testing	24	100 + DB	460.8	417.6	19.2	17.4
CALISO Certification	12	100	CALISO Certification	12	100	709.2	397.2	59.1	33.1
CALISO Certification with duct burner	12	100+DB	CALISO Certification with duct burner	12	100 + DB	336.4	400.8	28.0	33.4
Total CTG operation hours	**500**			**500**					

NOTES

DB - Duct Burner "ON"

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

(2) Steam Blows and restoration are based on a 7 day week

(3) Commissioning is based on a 6 day week

Lb/Day	NOx	CO
Facility Total (lbs)	31,771	39,316
Total/tons	15.9	19.7

Printed 11/10/2008 3:48 PM

ATTACHMENT E

CTG Steady State Emissions Data

GWF Tracy Combined Cycle Power Plant Project
Table 6.1B-10
Summary of Turbine Emissions - Criteria Pollutants

March 20, 2008
2x1 7EA Combined Cycle
Peak, Base and Part Load Emission Estimates, Revision 3

Case Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14
CTG Model	7EA	7EA	7EA	7EA	7EA	7EA	7EA	7EA	7EA	7EA	7EA	7EA	7EA	7EA
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	80%	60%	100%	100%	100%	80%	60%	100%	100%	80%	60%
CTG Inlet Air Cooling	Evap. Cooler	Off	Evap. Cooler	Off	Off	Evap. Cooler	Off	Evap. Cooler	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	59	59	59	59	59	115	115	115	115	115	15	15	15	15
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
CTG Heat Input, MBtu/h (LHV)	893	877	893	735	633	806	744	806	643	553	983	983	809	690
CTG Heat Input, MBtu/h (HHV)	991	974	991	816	702	895	828	895	714	614	1091	1091	899	766
Duct Burner Heat Input, MBtu/h (LHV)	292	0	0	0	0	292	0	0	0	0	292	0	0	0
Duct Burner Heat Input, MBtu/h (HHV)	324	0	0	0	0	324	0	0	0	0	324	0	0	0
NOx, ppmvd (dry, 15% O2)	2	2	2	2	2	2	2	2	2	2	2	2	2	2
NOx, ppmvd (dry)	2.7	2	2	2	2	2.8	1.9	2	2	2	2.6	2	2	2
NOx, ppmvw (wet)	2.4	1.8	1.8	1.9	1.9	2.4	1.8	1.8	1.8	1.8	2.4	1.9	1.9	1.9
NOx, lb/h as NO2	9.6	7.2	7.3	6.1	5.3	8.9	6.2	6.7	5.4	4.6	10.3	8.1	6.7	5.7
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0081	0.0082	0.0082	0.0083	0.0083	0.0081	0.0083	0.0083	0.0083	0.0084	0.0081	0.0082	0.0083	0.0083
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0073	0.0074	0.0074	0.0075	0.0075	0.0073	0.0075	0.0074	0.0075	0.0076	0.0073	0.0074	0.0074	0.0075
SCR NH3 slip, ppmvd (dry, 15% O2)	5	5	5	5	5	5	5	5	5	5	5	5	5	5
SCR NH3 slip, lb/h	8.75	6.45	6.6	5.4	4.65	8.1	5.5	5.95	4.75	4.1	9.4	7.25	5.95	5.1
CO, ppmvd (dry, 15% O2)	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CO, ppmvd (dry)	2.6	1.6	1.6	1.6	1.6	2.8	1.6	1.6	1.6	1.9	2.6	1.6	2	2
CO, ppmvw (wet)	2.4	1.5	1.5	1.5	1.5	2.4	1.5	1.5	1.5	1.7	2.3	1.5	1.8	1.9
CO, lb/h	5.7	3.5	3.6	2.9	2.5	5.3	3	3.2	2.5	2.6	6	3.9	3.8	3.3
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0048	0.004	0.004	0.0039	0.0039	0.0048	0.0041	0.004	0.0039	0.0047	0.0047	0.004	0.0047	0.0048
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0043	0.0036	0.0036	0.0036	0.0035	0.0044	0.0037	0.0036	0.0035	0.0042	0.0043	0.0036	0.0042	0.0043
SO2, ppmvd (dry, 15% O2)	0.14	0.1407	0.1407	0.1407	0.1407	0.14	0.1407	0.1407	0.1407	0.1407	0.14	0.1407	0.1407	0.1407
SO2, ppmvd (dry)	0.19	0.1389	0.1397	0.1417	0.1436	0.19	0.137	0.1409	0.1428	0.1376	0.18	0.1406	0.1422	0.144
SO2, ppmvw (wet)	0.17	0.129	0.1294	0.1315	0.1332	0.17	0.1248	0.127	0.1288	0.1254	0.17	0.1314	0.1328	0.1344
SO2, lb/h	0.92	0.6848	0.6969	0.5739	0.494	0.86	0.5807	0.6289	0.5019	0.4316	1	0.7673	0.6319	0.5385
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
VOC, ppmvd (dry, 15% O2)	2	1	1	1	1	2	1	1	1	1	2	1	1	1
VOC, ppmvd (dry)	2.5	0.8	0.8	0.8	0.8	2.8	0.8	0.9	0.8	1	2.4	0.8	0.9	0.9
VOC, ppmvw (wet)	2.3	0.8	0.8	0.8	0.8	2.4	0.8	0.8	0.8	0.9	2.2	0.8	0.9	0.9
VOC, lb/h as CH4	3.13	1.02	1.04	0.84	0.72	3.05	0.9	0.95	0.75	0.76	3.22	1.13	1.05	0.88
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0026	0.0012	0.0012	0.0011	0.0011	0.0028	0.0012	0.0012	0.0012	0.0014	0.0025	0.0011	0.0013	0.0013
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0024	0.0011	0.001	0.001	0.001	0.0025	0.0011	0.0011	0.001	0.0012	0.0023	0.001	0.0012	0.0012
PM10, lb/h	4.4	3.3	3.3	3.2	3.2	4.3	3.3	3.3	3.2	3.1	4.4	3.4	3.3	3.2
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0037	0.0038	0.0037	0.0044	0.005	0.0039	0.0044	0.0041	0.005	0.0057	0.0035	0.0035	0.0041	0.0047
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0033	0.0034	0.0034	0.004	0.0045	0.0035	0.0039	0.0037	0.0045	0.0051	0.0031	0.0031	0.0037	0.0042
PM2.5, lb/h	4.4	3.3	3.3	3.2	3.2	4.3	3.3	3.3	3.2	3.1	4.4	3.4	3.3	3.2
PM2.5, lb/MBtu (LHV) (incl. duct burner fuel)	0.0037	0.0038	0.0037	0.0044	0.005	0.0039	0.0044	0.0041	0.005	0.0057	0.0035	0.0035	0.0041	0.0047
PM2.5, lb/MBtu (HHV) (incl. duct burner fuel)	0.0033	0.0034	0.0034	0.004	0.0045	0.0035	0.0039	0.0037	0.0045	0.0051	0.0031	0.0031	0.0037	0.0042
Stack Exit Temperature, F	188	211	213	200	189	203	216	221	204	198	194	222	210	195
Stack Diameter, ft	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Stack Flow, lb/h	2405176	2359184	2391106	1939220	1647938	2190704	2052939	2176634	1705795	1519255	2615657	2601587	2118777	1784601
Stack Flow, scfm	535953	522952	530427	429860	365568	493274	458490	487566	380961	339300	580676	575384	468603	394694
Stack Flow, acfm	673048	680231	692225	550092	459775	633844	600485	643921	490416	432734	736307	760531	608442	501175
Stack Exit Velocity, ft/s	49	50	51	40	34	47	44	47	36	32	54	56	45	37
Stack Exhaust Moisture Content Percent Wet	9.25	7.10	7.34	7.22	7.30	11.90	8.88	9.86	9.11	8.90	8.27	6.51	6.57	6.65

ATTACHMENT F

CTG Startup and Shutdown Emissions Data

GWF Tracy Combined Cycle Power Plant Project
Table 5.1B-2
Start-Up Emission Rates - Event Data at 15°F

GWF - Tracy (15°F, 100% RH, 14.61psia)

2X1 GE 7EA STARTUP EMISSION ESTIMATES			
	HOT START	WARM START	COLD START
NOx, LBM	48	483	781
CO, LBM	202	698	1,125
UHC, LBM	17	65	103
VOC, LBM	3.4	13	21
SO2, LBM	2.5	5.0	8.2
PARTICULATES, LBM (FRONT HALF)	3.0	6.8	11
PARTICULATES, LBM (BACK HALF)	3.0	6.8	11
TOTAL PM, LBM	6.0	13.6	22.0
STARTUP DURATION, MIN	61	118	180

Client: GWF
Project Name: Tracy Combined Cycle Conversion
Project Number: 160129.0050
Date: January 30, 2008

BLACK & VEATCH

GWF Tracy Combined Cycle Power Plant Project
Table 5.1B-3
Start-Up Emission Rates - Event Data at 59°F

GWF - Tracy (59°F, 60% RH, 14.61psia)

2X1 GE 7EA STARTUP EMISSION ESTIMATES

	HOT START	WARM START	COLD START
NOx, LBM	29	162	253
CO, LBM	93	320	286
UHC, LBM	8	19	31
VOC, LBM	1.5	3.8	6.1
SO2, LBM	2.2	4.7	7.5
PARTICULATES, LBM (FRONT HALF PM10)	3.4	6.8	11
PARTICULATES, LBM (BACK HALF PM10)	3.4	6.8	11
STARTUP DURATION, MIN	61	118	180

Client: GWF
Project Name: Tracy Combined Cycle Conversion
Project Number: 160129.0050
Date: January 30, 2008

BLACK & VEATCH

GWF Tracy Combined Cycle Power Plant Project
Table 5.1B-4
Start-Up Emission Rates - Event Data at 115°F

GWF - Tracy (115°F, 30% RH, 14.61psia)

2X1 GE 7EA STARTUP EMISSIONS ESTIMATES			
	HOT START	WARM START	COLD START
NOx, LBM	48	449	735
CO, LBM	143	663	1,063
UHC, LBM	11	51	80
VOC, LBM	2.1	10	16
SO2, LBM	1.8	3.6	6.5
PARTICULATES, LBM (FRONT HALF)	3.8	10	11
PARTICULATES, LBM (BACK HALF)	3.8	10	11
STARTUP DURATION, MIN	61	118	180

Client: GWF
Project Name: Tracy Combined Cycle Conversion
Project Number: 160129.0050
Date: January 30, 2008

BLACK & VEATCH

GWF Tracy Combined Cycle Power Plant Project
Table 5.1B-5
Start-Up Emission Rates - Worst Case 1-Hour Emissions

GWF - Tracy

2X1 GE 7EA WORST EMISSIONS ESTIMATES IN 1 HOUR DURING STARTUP	
	WORST PERIOD EMISSIONS DURING STARTUP
NOx, LBM	399
CO, LBM	375
UHC, LBM	53
VOC, LBM	11
SO2, LBM	4.9
PARTICULATES, LBM (FRONT HALF)	4.7
PARTICULATES, LBM (BACK HALF)	4.7
TOTAL PM, LBM	9.4
DURATION, MIN	60

Client:	GWF
Project Name:	Tracy 2X1 GE 7EA
Project Number:	160129.0050
Date:	January 30, 2008

BLACK & VEATCH

GWF Tracy Combined Cycle Power Plant Project
Table 5.1B-6
Shutdown Emission Rates - Event Data at 15°F

GWF - Tracy (15°F, 100% RH, 14.61psia)

2X1 GE 7EA SHUTDOWN EMISSIONS ESTIMATES	
	SHUTDOWN
NOx, LBM	208
CO, LBM	296
UHC, LBM	26
VOC, LBM	5.2
SO2, LBM	1.7
PARTICULATES, LBM (FRONT HALF)	3.0
PARTICULATES, LBM (BACK HALF)	3.0
TOTAL PM, LBM	6.0
SHUTDOWN DURATION,	39

Client:	GWF
Project Name:	Tracy Combined Cycle Conversion
Project Number:	160129.0050
Date:	January 30, 2008

BLACK & VEATCH

GWF Tracy Combined Cycle Power Plant Project
Table 5.1B-7
Shutdown Emission Rates - Event Data at 59°F

GWF - Tracy (59°F, 60% RH, 14.61psia)

2X1 GE 7EA SHUTDOWN EMISSIONS ESTIMATES	
	SHUTDOWN
NOx, LBM	77
CO, LBM	99
UHC, LBM	8.2
VOC, LBM	1.7
SO2, LBM	2.1
PARTICULATES, LBM (FRONT HALF)	3.0
PARTICULATES, LBM (BACK HALF)	3.0
SHUTDOWN DURATION,	39

Client:	GWF
Project Name:	Tracy Combined Cycle Conversion
Project Number:	160129.0050
Date:	January 30, 2008

BLACK & VEATCH

GWF Tracy Combined Cycle Power Plant Project
Table 5.1B-8
Shutdown Emission Rates - Event Data at 115°F

GWF - Tracy (115°F, 30% RH, 14.61psia)

2X1 GE 7EA SHUTDOWN EMISSIONS ESTIMATES	
	SHUTDOWN
NOx, LBM	200
CO, LBM	282
UHC, LBM	21
VOC, LBM	4.2
SO2, LBM	1.8
PARTICULATES, LBM (FRONT HALF)	3.0
PARTICULATES, LBM (BACK HALF)	3.0
SHUTDOWN DURATION,	39

Client:	GWF
Project Name:	Tracy Combined Cycle Conversion
Project Number:	160129.0050
Date:	January 30, 2008

BLACK & VEATCH

GWF Tracy Combined Cycle Power Plant Project
Table 5.1B-9
Shutdown Emission Rates - Worst Case 1-Hour Emissions

2X1 GE 7EA WORST EMISSIONS ESTIMATES IN 1 HOUR DURING SHUTDOWN	
	WORST PERIOD EMISSIONS DURING SHUTDOWN
NOx, LBM	212
CO, LBM	298
VOC, LBM	6.3
SO2, LBM	2.5
PARTICULATES, LBM (FRONT HALF)	3.8
PARTICULATES, LBM (BACK HALF)	3.8
TOTAL PM, LBM	7.5
DURATION, MIN	60

Notes
Shutdown takes 39 minutes. Balance of hour filled with 21 minutes of 15F baseload emissions.

ATTACHMENT G

Daily and Annual Turbine Emissions Spreadsheets

Emission Inputs			
Pollutant	Nox and CO Calculations	VOC, PM10, and So2 Calculations	NH3 Calculations
Total Hours of Operation	24.0	24	24
Cold Startups/day	1	1	0
Minutes Cold Startup/day	180	180	0
Hours Cold Startup/day	3.0	3.0	0
Hot Startups/day	1	0	0
Minutes Hot Startup/day	61	61	0
Hours Hot Startup/day	1.0	0.0	0
Shutdowns/day	2	1	0
Minutes/Shutdown	39	39	0
Hours Shutdown/day	1.3	0.7	0
Hours Operation - (Startup and Shutdown)	18.7	20.4	24

Emission Rates	NOx	CO	VOC	SOx	PM10	NH3
Cold Startup (lb/event)	390.5	562.5	10.5	4.1	11	0
Hot Startup (lb/event)	24	101	1.7	1.25	3	0
Shutdown (lb/event)	104.0	148.0	2.6	1.05	3.0	0
Normal Operation (lb/hr)	10.3	6	3.22	2.63	5.8	9.4
Cold Startup Emissions/day	390.5	562.5	10.5	4.1	11.0	0.0
Hot Startup Emissions/day	24.0	101.0	0.0	0.0	0.0	0.0
Shutdown Emissions/day	208.0	296.0	2.6	1.1	3.0	0.0
Normal Operation emissions/day	192.4	112.1	65.5	53.5	118.0	225.6
Total Emissions/day	814.9	1071.6	78.6	58.7	132.0	225.6

Emission Inputs	
Cold Startups/year	25
Minutes/Cold startup	180
Hours Cold Startup/year	75.0
Warm Startups/year	50
Minutes/Warm startup	118
Hours Warm Startup/year	98.3
Hot Startups/year	250
Minutes/Hot startup	61
Hours Hot Startup/year	254.2
Shutdowns	325
Minutes/Shutdown	39
Hours Shutdown/Year	211.3
Hours Normal Operation (W/Duct Burner)	3100
Hours Normal Operation (W/O Duct Burner	4900

Emission Rates	NOx	CO	VOC	SOx	PM10	NH3
Cold Startup (lb/event)	126.50	143.00	3.05	3.75	11.00	0.00
Warm Startup (lb/event)	81.00	160.00	1.90	2.35	6.80	0.00
Hot Startup (lb/event)	14.50	46.50	0.75	1.10	3.40	0.00
Shutdown (lb/event)	38.50	49.50	0.85	1.05	3.00	0.00
Normal Operation (lb/hr) 59 deg F 100% fire, w/Duct B	9.60	5.70	3.10	0.92	4.40	8.75
Normal Operation (lb/hr) 59 deg F 100% fire, wo/Duct B	7.30	3.60	1.00	0.69	3.30	6.60
Cold Startup Emissions/year	3163	3575	76	94	275	0
Warm Startup Emissions/year	4050	8000	95	118	340	0
Hot Startup Emissions/year	3625	11625	188	275	850	0
Shutdown Emissions/year	12513	16088	276	341	975	0
Normal Operation w/duct burner Emissions/year	29760	17670	9610	2855	13640	27125
Normal Operation wo duct burner Emissions/year	35770	17640	4900	3401	16170	32340
Total Emissions/year	88881	74598	15145	7084	32250	59465

ATTACHMENT H

SJVAPCD BACT Guideline 3.4.7

Best Available Control Technology (BACT) Guideline 3.4.7
Last Update: 10/1/2002
Gas Turbine - = or > 50 MW , Uniform Load, without Heat Recovery

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).		
NOx	5.0 ppmvd** @ 15% O2, based on a three-hour average (high temp SCR, or equal).	1. 2.5 ppmvd** @ 15% O2, based on a one-hour average (high temperature Selective Catalytic Reduction (SCR), or equal). 2. 3.0 ppmvd** @ 15% O2, based on a three-hour average (high temp SCR, or equal).	
PM10	Air inlet cooler/filter, lube oil vent coalescer (or equal) and either PUC regulated natural gas, LPG, or non-PUC-regulated gas with < 0.75 grams S/100 dscf.		
SOx	PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with = or < 0.75 grams S/100 dscf.		
VOC	2.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).	1. 0.6 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst). 2. 1.3 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).	

ATTACHMENT I

Pre-Project Actual Emissions Data

Turbine #1			
Year	Fuel Usage (MMBtu/year)	Permitted Emission Limit (lb/MMBtu) via F-factor	NOx (lb/year)
2003	149136	0.0184	2744
2004	91271	0.0184	1679
2005	51203	0.0184	942
2006	99341	0.0184	1828
2007	84486	0.0184	1555
Average	**95087.4**	**0.0184**	**1750**

Turbine #2			
Year	Fuel Usage (MMBtu/year)	Permitted Emission Limit (lb/MMBtu) via F-factor	NOx (lb/year)
2003	155299	0.0184	2858
2004	46062	0.0184	848
2005	66980	0.0184	1232
2006	99341	0.0184	1828
2007	87047	0.0184	1602
Average	**90945.8**	**0.0184**	**1673**

471 BHP Emergency Engine			
Year	Hours Operated (non-emergency)	Permitted Emission Limit (g/bhp-hr)	NOx (lb/year)
2003	13	4.69	63
2004	14.65	4.69	71
2005	5.5	4.69	27
2006	13	4.69	63
2007	31	4.69	151
Average	**15.43**	**4.69**	**75**

Estimated Average Actual NOx Emissions (lb/year)	
Turbine #1	1750
Turbine #2	1673
IC Engine	75
Total	**3498**

ATTACHMENT J

Quarterly Net Emissions Change

QNEC Calculations

N-4597-1-5

QNEC = (PE2 – BE) ÷ 4

As shown in Section VII.C.5, BE is equal to PE1 for all pollutants. Therefore, the equation for QNEC reduces to:

QNEC = (PE2 – PE1) ÷ 4

Pollutant	PE2 (lb/year)	PE1 (lb/year	QNEC (lb/qtr)
NOx	88,881	153,460	-16,144.75
SOx	7,084	5,600	371.00
PM10	32,250	26,667	1,395.75
CO	74,598	71,620	744.50
VOC	15,145	13,356	447.25

N-4597-2-5

QNEC = (PE2 – BE) ÷ 4

As shown in Section VII.C.5, BE is equal to PE1 for all pollutants. Therefore, the equation for QNEC reduces to:

QNEC = (PE2 – PE1) ÷ 4

Pollutant	PE2 (lb/year)	PE1 (lb/year	QNEC (lb/qtr)
NOx	88,881	153,460	-16,144.75
SOx	7,084	5,600	371.00
PM10	32,250	26,667	1,395.75
CO	74,598	71,620	744.50
VOC	15,145	13,356	447.25

N-4597-4-2

QNEC = (PE2 – BE) ÷ 4

As shown in Section VII.C.5, BE is equal to PE1 for all pollutants. Therefore, the equation for QNEC reduces to:

QNEC = (PE2 – PE1) ÷ 4

Pollutant	PE2 (lb/year)	PE1 (lb/year	QNEC (lb/qtr)
NOx	243	974	-182.75
SOx	0	1	-0.25
PM10	2	6	-1.00
CO	76	25	12.75
VOC	2	8	-1.50

N-4597-5-0

QNEC = (PE2 – BE) ÷ 4

As shown in Section VII.C.5, BE is equal to PE1 for all pollutants. Therefore, the equation for QNEC reduces to:

QNEC = (PE2 – PE1) ÷ 4

Pollutant	PE2 (lb/year)	PE1 (lb/year	QNEC (lb/qtr)
NOx	2,482	0	620.50
SOx	238	0	59.50
PM10	2,380	0	595.00
CO	12,580	0	3,145.00
VOC	1,700	0	425.00

N-4597-6-0

QNEC = (PE2 – BE) ÷ 4

As shown in Section VII.C.5, BE is equal to PE1 for all pollutants. Therefore, the equation for QNEC reduces to:

QNEC = (PE2 – PE1) ÷ 4

Pollutant	PE2 (lb/year)	PE1 (lb/year	QNEC (lb/qtr)
NOx	85	0	21.25
SOx	0	0	0.00
PM10	4	0	1.00
CO	76	0	19.00
VOC	5	0	1.25

ATTACHMENT K

BACT Guideline 3.4.2 and CTG Top Down BACT Analysis

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 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.

ATTACHMENT K

BACT Guideline 3.4.2 and CTG Top Down BACT Analysis

I. Steady State 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 NO_X @ 15% O_2, based on a 1-hour average, excluding startup or shutdown (SCR or equal)

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

- 2.0 ppmvd NO_X @ 15% O_2, based on a 1-hour average, excluding startup or shutdown (SCR 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 NO_X @ 15% O_2 (SCR, or equal)
2. 2.5 ppmvd NO_X @ 15% O_2 (SCR, 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-hour average), except during startup or shutdown. 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 use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.0 ppmv @ 15% O_2 (1-hour average). 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-hour average). Therefore, BACT is satisfied.

II. Startup and Shutdown NO_X Top-Down BACT Analysis

SJVAPCD BACT Clearinghouse Guideline 3.4.2 currently does not list any control technologies/strategies or emission reduction practices for NO_X emissions during startup and shutdown periods. In accordance with comments received by EPA and the California Energy Commission (CEC), the District will perform a project specific top-down BACT analysis for startup and shutdown periods.

The Environmental Protection Agency (EPA), California Air Resources Board (CARB), San Diego County Air Pollution Control District (SDCAPCD), South Coast Air Quality Management District (SCAQMD), Bay Area Air Quality Management District (BAAQMD) and the San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT clearinghouses were reviewed to determine potential control technologies for this class and category of operation, but no BACT guidelines for gas turbines within combined cycle power plants were found that addressed specific requirements for startup and shutdown periods.

Step 1 - <u>Identify All Possible Control Technologies</u>

Startup and Shutdown emission rates are much greater than steady state emissions for NOx and CO[1]; therefore, BACT FOR NOx emitted during startup and shutdown is not covered by the steady state NOx Top-Down Analysis. Since BACT is triggered for NOx, an analysis of BACT for NOx during startup is required. The following possible control technologies have been identified:

1. GE OpFlex Startup NOx

   GE OpFlex Startup NOx and Startup Fuel Heating system is a series of enhancements designed to expand the operating profile of gas turbines while maintaining or lowering emissions. The OpFlex Startup NOx system uses proprietary GE advanced fuel scheduling technology to reduce startup and shutdown NOx emissions. This technology has been used to limit gas turbine emissions to less than 25 ppm at the turbine outlet (prior to controls).

2. GE Rapid Response Technology

   GE offers its "Rapid Response" technology that reduces startup time of the turbine and startup NOx and CO emissions. This system allows the gas turbines in a combined cycle plant to startup in a similar process as a simple cycle unit. The typical gas turbine at a combined cycle plant will initially fire and ramp up to approximately 20% load. The turbine is then be held at 20% load while the steam systems are slowly brought online. This method of starting up the system is slow, since the operator must avoid ramping the temperature up to fast which can cause stress cracks in the system from thermal expansion. This hold at 20% load increases the time that the system spends in startup mode.

[1] Note, BACT for CO is not triggered since facility emissions are below 200,000 lb/year.

Rapid Response accomplishes a faster startup by breaking the startup of the gas turbine free of the steam cycle. The system is equipped with a steam bypass that allows the hot exhausts to circumvent the steam cycle during startup, allowing the turbine to ramp up directly to nearly 100% load. This method of operating the unit allows the gas turbine to sync to the power grid within approximately 10 minutes of ignition. The steam cycle is then gradually brought online while the unit is synched to the power grid.

The key elements of the GE Rapid Response package are:

a. A Power Island Integrated System Controller
b. An HRSG designed to handle loading ramp rate of the gas turbines
c. A hybrid steam bypass system designed to accept 100% of the gas turbine load during startup
d. Steam control and valve modifications
e. Purge credit for gas turbines (purge cycle is activated on shutdown instead of during startup)
f. A startup gas turbine fuel heating system that is independent of the HRSG

GE advertises a 10-minute start capability for this system; however, this 10-minute startup time should not be confused with the startup time that is defined in District Rule 4703. The 10 minute startup time listed in Siemens literature is defined as the time it takes from turbine startup to reach 100% load and sync with the electrical generator. This does not include the time necessary to bring emission controls to temperature, such that the plant meets steady state emission limits.

3. Siemens Rapid Start Technology

Siemens offers two fast start HRSG designs in its HRSG portfolio. The first is the use of a Benson once-through HRSG, which replaces the thick-walled high pressure steam drums that are typically used with external steam separators and a surge bottle. Pursuant to Siemens literature, this design is especially suited for triple-pressure reheat F-class combined cycle applications.

The second HRSG design is a modified drum design, which has similar characteristics to the once-through design. This design reduces the diameter of the steam drum, which functions as primary steam separation and water inventory. Secondary steam separation is accomplished external to the drum. In addition to the HRSG designs, the Siemens Rapid Start Technology utilizes steam bypass and conditioning systems, along with a patented steam turbine stress controller and an SPPA T3000 control system to optimize plant startup.

Siemens literature advertises a 10-minute start capability for this system; however, this startup time should not be confused with the startup time that is defined in District Rule 4703. The 10 minute startup time listed in Siemens literature is defined as the time it takes from turbine startup to reach 100% load and sync with the electrical generator. This does not include the time necessary to bring emission controls to temperature, such that the plant meets steady state emission limits.

4. SCR System Operation with NH_3 Injection at Feasible Catalyst Temperatures during Startup and Shutdown Periods

   EPA has indicated that most combined cycle power plants have requirements within their permits stating that ammonia injection in to the SCR system shall begin at the earliest feasible catalyst temperature to ensure NO_X reduction reactions can occur with a reasonable amount of ammonia slip. This will be included as an option in the BACT analysis.

Step 2 - Eliminate Technologically Infeasible Options

1. GE OpFlex Startup NOx

   Pursuant to GE literature, the applicability of OpFlex Startup NOx is limited to Frame $7FA_{+e}$ (PG7241) gas turbines with DLN2.6 combustors and Mark V or higher controls. The proposed Frame 7EA turbines are equipped with DLN 1 combustors and therefore don't meet the applicability requirements listed in GE literature. Pursuant to discussions with GE Power Systems, OpFlex Startup NOx could possibly be adapted to Frame 7EA turbines; however, GE Power Systems couldn't guarantee startup NOx emission reductions for the 7EA systems operated at GWF Tracy. Since this control technology is currently only packaged for Frame $7FA_{+e}$ turbines and GE can't guarantee emission reductions if adapted to 7EA turbines, this control technology is considered technologically infeasible and will be eliminated from consideration.

2. GE Rapid Response Technology

   While GE advertises that this technology is available for F Class turbines, Scott Dayer and Robert Gordon of GE Power System have indicated that this system could be made readily available for E Class turbines. Pursuant to Scott Dayer and Robert Gordon, there are currently no facilities currently operating with GE's Rapid Response technology. They stated that one Rapid Response unit had been sold for a proposed plant in Victorville, CA; however, construction of that plant was delayed due to the current economic climate. Therefore, this technology will be considered Technologically Feasible and will not be considered Achieved in Practice for the purposes of this evaluation.

3. Siemens Rapid Start Technology

   Siemens issued a technical document titled "Integrated Technologies that Enhance Power Plant Operating Flexibility" in 2007 that indicates that Siemens Fast Start technology is only feasible in combined cycle power plant operations configured with Siemens F-class gas turbines. Therefore, this technology will not be considered as Technologically Feasible.

4. SCR System Operation with NH_3 Injection at Feasible Catalyst Temperatures during Startup and Shutdown Periods

   EPA has indicated that most combined cycle power plants have requirements within their permits stating that ammonia injection in to the SCR system shall begin at the earliest feasible catalyst temperature to ensure NO_X reduction reactions can occur with a reasonable amount of ammonia slip. Therefore, this control option will be considered to be Achieved in Practice.

Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>

The following options are ranked based on their emission factor:

1. GE Rapid Response Technology (Technologically Feasible)
2. SCR Sysem Operation with NH_3 Injection at Feasible Catalyst Temperatures during Startup and Shutdown Periods (Achieved in Practice)

Step 4 - <u>Cost Effective Analysis</u>

A cost effective analysis must be performed for the technologically feasible control options listed in step 3 to determine the the cost effectiveness of the listed items. The only technologically feasible item listed is GE Rapid Response Technology.

<u>Capital Cost for GE Rapid Response Technology</u>

Pursuant to Scott Dayer of GE Power Systems, the approximate difference in capital cost between a typical turbine and a turbine equipped with Rapid Response is approximately $2,000,000 per turbine. Thus,

Capital Cost = $2,000,000

Pursuant to the District's BACT policy, the capital cost must be annualized as follows:

$A = P * i(1+i)^n \div [(1+i)^n - 1)$

where,

A = Equivalent Annual Control Equipment Capital Cost
P = Present value of the control equipment, including installation cost ($2,000,000)
i = interest rate (10% = 0.1).
n = equipment life (10 years)

$A = \$2,000,000 * 0.1(1+0.1)^{10} \div [(1+0.1)^{10} - 1]$

A = $325,491/year

Emission Reductions for GE Rapid Response Technology

Pursuant to Robert Gordon of GE Power Systems, the estimated reduction in startup emissions for a GE Frame 7FA turbine ranges from 20% to 50%. The estimated reduction that could be achieved on a Frame 7EA turbine has not been analyzed. A 50% control efficiency for startup and shutdown emissions will conservatively be assumed for the Frame 7EA turbine served by GE Rapid Response Technology.

Pursuant to the emission summary in Attachment G, the startup and shutdown emissions for a single turbine is:

Mode of Operation	Emissions (lb/year)
Cold Startup (lb/year)	3,163
Warm Startup (lb/year)	4,050
Hot Startup (lb/year)	3,625
Shutdown (lb/year)	12,513
Total	**23,351**

Assuming Rapid Response could achieve 50% control of both startup and shutdown emissions, the reduction in startup and shutdown emissions would be:

Emission Reductions = 23,351 lb-NOx/year x 0.5 x 1 ton/2000 lb
Emission Reductions = 5.84 tons-NOx/year

Cost per Ton of Reductions

The cost per ton of NOx reductions for GE Rapid Response Technology is:

Cost/ton = $325,491/year ÷ 5.83 tons-NOx/year
Cost/ton = $55,735/ton of NOx reduced

This cost is greater than the District's current NOx cost effectiveness threshold of $24,500/ton of NOx reduced. Additionally, the assumptions used in this analysis were very conservative. There has been no indication from GE that their Rapid Response technology reduces shutdown emissions, which were included in the quantity of emissions reduced. Additionally, the advertised reduction emissions for a Frame 7FA turbine is 20% in GE literature, while 50% control was utilized in this analysis. GE's Rapid Response is not considered to be a cost-effective control per the District's BACT policy and will be removed from consideration. While this option has been eliminated from consideration, it should be noted that Scott Dayer and Robert Gordon of GE Power Systems reviewed GWF Tracy's design and concluded that GE couldn't guarantee that their Rapid Response technology would reduce emissions at this plant and stated that the design at the GWF Tracy Plant may be roughly equivalent to the Rapid Response technology that GE offers.

Step 5 - Select BACT

BACT for each turbine is "SCR System Operation with NH_3 Injection at Feasible Catalyst Temperatures during Startup and Shutdown Periods". The permits will include conditions that require the injection of ammonia at the earliest feasible catalyst temperature. The minimum temperature for injection of ammonia will be determined during the final design phase of the combined cycle plant.

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% O_2, based on a three-hour average

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

- 1.5 ppmvd VOC @ 15% O_2, based on a three-hour average

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 @ 15% O_2, based on a three hour average
2. 2.0 ppmvd @ 15% O_2, based on a three hour average

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 1.5 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 District recently researched the background behind the technologically feasible limit of 1.5 ppmvd @ 15% O_2 and determined that this option was only applicable to the unit while firing without a duct burner (see recently approved Avenal Power Center project C-1080386. Therefore the applicants proposed 1.5 ppmvd VOC @ 15% O_2 emission factor when firing without a duct burner has been determined 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 when firing with the duct burner and 1.5 ppmvd @ 15% O_2 when firing without the duct burner. The facility has proposed the use of natural gas with the above emission limits. Therefore, BACT for VOC has been satisfied.

IV. 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

- Air inlet filter, lube oil vent coalescer, and natural gas fuel, or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use an air inlet cooler/filter, lube oil vent coalescer, and 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 an air inlet cooler/filter, lube oil vent coalescer and PUC-regulated natural gas fuel. GWF Tracy is proposing to use an air inlet cooler/filter, lube oil vent coalescer and PUC-regulated natural gas fuel; therefore, BACT is satisfied.

V. SO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel

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

- Non PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf, 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 of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Non PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf, or equal
2. PUC-regulated natural gas fuel.

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 with 0.25 grains S/100 dscf. This is equivalent to 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, LPG, or non-PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf. GWF-Tracy has proposed to fire each of these turbines on PUC-regulated natural gas fuel with 0.25 grains S/100 dscf or less; therefore, BACT is satisfied.

ATTACHMENT L

BACT Guideline 3.1.3 and Emergency Engine Top Down BACT Analysis

Per » B A C T » Bact Guideline.asp?category Level1=3&category Level2=1&category Level3=3&last Update=6 » 30 :

Best Available Control Technology (BACT) Guideline 3.1.3
Last Update: 6/30/2001
Emergency Diesel I.C. Engine = or > 400 hp

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	2.0 grams/brake horsepower-hour	= or < 1.4 grams/bhp-hr	
NOx	Certified emissions of 6.9 g/bhp-hr or less		
PM10	0.1 grams/bhp-hr (if TBACT is triggered) 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		

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)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.3 identifies achieved in practice BACT as the following:

- Certified emissions of 6.9 g/bhp-hr or less

SJVAPCD BACT Clearinghouse Guideline 3.1.3 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.3 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 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 is proposing the use of an engine with certified emissions of 6.9 g/bhp-hr or less. 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 engine that has certified NOx emissions of 6.9 g/bhp-hr or less. The facility has proposed to use of an IC engine that has certified NOx emissions of 4.69 g/bhp-hr. Therefore, BACT is satisfied.

ATTACHMENT M

BACT Guideline 1.1.2 and Boiler Top Down BACT Analysis

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 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).

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 ppmvd NOx @ 3% O_2 (ultra-low NOx main burner system or equivalent)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies technologically feasible BACT as the following:

- 9.0 ppmvd NOx @ 3% O_2 (SCR, Low Temperature Oxidation (LTO), or equivalent)

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 NOx @ 3% O_2 (SCR, LTO, or equivalent)
2. 9.0 ppmvd NOx @ 3% O_2 (Ultra-Low NOx burner or equivalent)

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 boiler with a NOx emissions limit of 6 ppmvd NOx @ 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 the use of a boiler that meets an emissions limit of 9 ppmvd NOx or less. The facility has proposed to use of a boiler that meets an emissions limit of 6 ppmvd NOx or less. Therefore, BACT is satisfied.

II. PM_{10} 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:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT options.

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. Natural gas fuel with LPG backup

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 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. The facility has proposed to use of a boiler that uses natural gas fuel. Therefore, BACT is satisfied.

III. VOC 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:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT options.

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. Natural gas fuel with LPG backup

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 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. The facility has proposed to use of a boiler that uses natural gas fuel. Therefore, BACT is satisfied.

ATTACHMENT N

BACT Guideline 3.1.4 and Fire Pump Engine Top Down BACT Analysis

Per » B A C T » Bact Guideline.asp?category Level1=3&category Level2=1&category Level3=4&last Update=6 » 30 :

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 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)

I. NO_X Top-Down BACT Analysis

Step 1 - <u>Identify All Possible Control Technologies</u>

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Certified NOx emissions of 6.9 g/bhp-hr or less

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any technologically feasible BACT options.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

All control options listed in step 1 are technologically feasible.

Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>

The following options are ranked based on their emission factor:

4. Certified NOx emissions of 6.9 g/bhp-hr or less

Step 4 - <u>Cost Effective Analysis</u>

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 an engine that has certified NOx emissions of 6.9 g/bhp-hr or less. 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 use of an engine that has certified NOx emissions of 6.9 g/bhp-hr or less. The facility has proposed to use of an engine that is Tier 3 certified. Therefore, BACT is satisfied.

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 Laboratory Certification)

SJVAPCD BACT Clearinghouse Guideline 3.1.4 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 emission factor:

1. Catalytic Oxidation
2. Positive Crankcase Ventilation

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.

This unit is required to be certified by the Underwriters Laboratory (UL). The UL certification for the proposed fire pump does not include an oxidation catalyst. Adding an oxidation catalyst to this system would void the UL certification for the unit. Therefore, the use of an oxidation catalyst will be removed from consideration.

The applicant is proposing the use of a positive crankcase ventilation system. This is the highest ranking control option remaining from 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 use of a positive crankcase ventilation system. The facility has proposed an engine that is equipped with a positive crankcase ventilation system. Therefore, BACT is satisfied.

ATTACHMENT O

Interpollutant Offset Analysis

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 2

ANALYSES INCLUDED IN INTERPOLLUTANT EVALUATION 3

- FACTORS CONSIDERED 3
- ELEMENTS FROM 2008 PM 2.5 PLAN 3
- EXTENSION BY ADDITIONAL ANALYSIS 4
- STRENGTHS 4
- LIMITATIONS 5

ANALYSES CONTAINED IN RECEPTOR MODELING 6

- FACTORS CONSIDERED 6
- ANALYSES IN RECEPTOR MODELING THAT USE INPUT FROM REGIONAL MODELING 6
- EXTENSION BY ADDITIONAL ANALYSIS 6
- STRENGTHS 6
- LIMITATIONS 7

ANALYSES CONTAINED IN REGIONAL MODELING 8

- FACTORS CONSIDERED 8
- EXTENSION BY ADDITIONAL ANALYSIS 8
- STRENGTHS 9
- LIMITATIONS 9

RESULTS AND DOCUMENTATION 10

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 P

Compliance Certification for GWF Facilities

GWF®

GWF POWER SYSTEMS

January 20, 2009

Mr. David Warner, Director of Permit Services
San Joaquin Valley Air Pollution Control District
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244

RE: Project No C-1083169 (GWF Hanford), C-1083176 (GWF Henrietta), N-1083212 (GWF Tracy) – GWF Energy LLC Certification of Compliance

Dear Mr. Warner:

Pursuant to SJVPCD (District) Rule 2201 Section 4.15.2, Compliance by *Other Owned, Operated or Controlled Source*, GWF Power Systems, Inc. (GWF) on behalf of GWF Power Systems, L.P., Hanford LP and GWF Energy LLC respectfully submits this ***Letter of Certification*** as it pertains to GWF's California "Major Source" facilities.

I hereby certify that all GWF facilities in the State of California are in compliance or are on a schedule for compliance with all applicable emissions limitations and standards. This certification shall speak as to the date of its execution.

Thank you for your time and consideration regarding this certification. Should you have any questions regarding this matter, please call me at 925.431.1440.

Respectfully,

GWF Power Systems, Inc.

Mark Kehoe
Director, Environmental and Safety Programs

cc: D. Wheeler, GWF

ATTACHMENT Q

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Air Pollution Control District
Risk Management Review

To: James Harader, AQE – Permit Services

From: Jaime Horio, AQS – Technical Services

Date: January 15, 2009

Facility Name: GWF Energy

Location: Sec 36, Town 2 South, Range 4 East

Application #(s): N-4597-1-5, 2-5, 4-2, 5-0, 6-0

Project #: N-1083212

A. RMR SUMMARY

RMR Summary							
Categories	**Turbine (1-5)**	**Turbine (2-5)**	**Diesel ICE (4-2)**	**Boiler (5-0)**	**Fire Pump (6-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	NA[1]	NA[1]	NA[1]	NA[1]	NA[1]	>1.0	>1.0
Acute Hazard Index	3.6e-2	3.3e-2	0.533	6.41e-4	0.188	0.79	0.79
Chronic Hazard Index	3.55e-2	3.53e-2	2.96e-5	7.64e-4	6.03e-5	0.07	0.07
Maximum Individual Cancer Risk (10^{-6})	0.5	0.47	0.079	0.019	0.159	1.24	1.24
T-BACT Required?	**No**	**No**	**No**	**No**	**No**		
Special Permit Conditions?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**		

1 Prioritization for this unit was not conducted since it has been determined that all diesel-fired IC engines will result in a prioritization score greater than 1.0, therefore this project's Prioritization Score is greater than 1.0.

<u>Proposed Permit Conditions</u>

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

<u>Unit # 1-5, 2-5, 5-0</u>

1. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102] N

<u>Unit # 4-2</u>

2. Modified {1901} The PM10 emissions rate shall not exceed **0.029** g/hp-hr based on US EPA certification using ISO 8178 test procedure. [District Rule 2201]
3. {1902} The sulfur content of the diesel fuel used shall not exceed 0.0015% by weight. [District Rule 2201] N

4. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102] N

Unit # 6-0

5. Modified {1901} The PM10 emissions rate shall not exceed **0.13** g/hp-hr based on US EPA certification using ISO 8178 test procedure. [District Rule 2201]
6. {1902} The sulfur content of the diesel fuel used shall not exceed 0.0015% by weight. [District Rule 2201] N
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] N
4. {1344} The engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed **100** hours per year. [District NSR Rule and District Rule 4701] N

B. RMR REPORT

I. Project Description

Technical Services received a request on December 29, 2008, to perform an Ambient Air Quality Analysis and a Risk Management Review for a modifications to two turbines, two diesel-fired IC engines, and a natural gas-fired boiler.

II. Analysis

Technical Services performed a review of the health risk modeling provided by the applicant. The AERMOD model was used, with the parameters outlined below and meteorological data for 2004 from Modesto to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 1-5, 2-5			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	45.7	**Closest Receptor (m)**	241
Stack Diameter. (m)	5.18	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	9.754	**Fuel Type**	NG
Stack Exit Temp. (°K)	365.37		

Analysis Parameters Unit 4-2			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	1.93	**Closest Receptor (m)**	241
Stack Diameter. (m)	0.16	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	65.78	**Fuel Type**	NG
Stack Exit Temp. (°K)	696.48		

Analysis Parameters Unit 5-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	15.24	**Closest Receptor (m)**	241
Stack Diameter. (m)	1.22	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	5.8	**Fuel Type**	NG
Stack Exit Temp. (°K)	422.04		

Analysis Parameters Unit 6-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	3.66	**Closest Receptor (m)**	241
Stack Diameter. (m)	0.15	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	40.87	**Fuel Type**	NG
Stack Exit Temp. (°K)	784.26		

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The emission rates used for criteria pollutant modeling were 245.7 lb/hr CO, 199.5 lb/hr NOx, 2.6 lb/hr SOx, and 5.8 lb/hr PM_{10} for the turbines. The emission rates used for criteria pollutant modeling were 3.14 lb/hr CO, 0.62 lb/hr NOx, 0.24 lb/hr SOx, and 0.6 lb/hr PM_{10} for the boiler. The emission rates used for criteria pollutant modeling were 1.52 lb/hr CO, 1.7 lb/hr NOx, 0.004 lb/hr SOx, and 0.08 lb/hr PM_{10} for the new engine.

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Diesel ICE	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.
[1]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with each unit is less than 1.0 in a million. **In accordance with the District's Risk Management**

Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

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

Attachments:

A. RMR request from the project engineer
B. Additional Information from the project engineer
C. Health Risk Scores
D. Ambient Air Quality Analysis
E. Facility Risk Summary

AQA for GWF (N-4597)
All Values are in ug/m^3

	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
AUXBOIL	1.440E+00	6.256E-02	7.960E+00	2.787E+00	7.432E-01	3.871E-01	1.545E-01	1.158E-01	4.741E-01	9.622E-02
HRSG1	5.513E+01	3.679E-01	9.829E+01	6.519E+01	9.581E-01	8.798E-01	4.548E-01	5.944E-03	9.567E-01	1.777E-01
HRSG2	5.809E+01	3.670E-01	9.821E+01	6.531E+01	1.009E+00	9.143E-01	4.479E-01	1.500E-03	9.756E-01	1.671E-01
PUMP	1.501E+01	1.911E-03	9.186E+00	2.960E+00	4.711E-02	1.274E-02	4.799E-03	0.000E+00	1.168E-01	1.400E-04
Background	1.014E+02	2.296E+01	4.311E+03	3.728E+03	3.464E+02	1.998E+02	8.260E+01	1.865E+01	8.300E+01	2.700E+01
Facility Totals	2.311E+02	2.376E+01	4.524E+03	3.864E+03	3.491E+02	2.020E+02	8.366E+01	1.877E+01	8.552E+01	2.744E+01
AAQS	338	56	23000	10000	655	1300	105	80	50	30
	Pass	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Fail**	**Pass**

EPA's Significatance Level (ug/m^3)

NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
0.0	1.0	2000.0	500.0	0.0	25.0	5.0	1.0	5.0	1.0

Project: 2.5043

AAQA Emission (g/sec)

Device	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
AUXBOIL	7.81E-02	3.57E-02	3.96E-01	3.96E-01	3.02E-02	3.02E-02	3.02E-02	1.39E-02	7.56E-02	3.42E-02
HRSG1	2.51E+01	1.28E+00	3.10E+01	3.10E+01	3.28E-01	3.28E-01	3.28E-01	1.02E-01	7.31E-01	4.64E-01
HRSG2	2.51E+01	1.28E+00	3.10E+01	3.10E+01	3.28E-01	3.28E-01	3.28E-01	1.02E-01	7.31E-01	4.64E-01
PUMP	2.14E-01	1.22E-03	1.91E-01	1.91E-01	5.04E-04	5.04E-04	5.04E-04	0.00E+00	1.01E-02	5.75E-05

ATTACHMENT R

Title V Significant Modification Application

San Joaquin Valley
Unified Air Pollution Control District

TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

I. TYPE OF PERMIT ACTION (Check appropriate box)

[ ] SIGNIFICANT PERMIT MODIFICATION
[x] MINOR PERMIT MODIFICATION
[ ] ADMINISTRATIVE AMENDMENT

COMPANY NAME: GWF Energy LLC – GWF Tracy Combined Cycle Power Plant	FACILITY ID: N- 4597
1. Type of Organization:[X] Corporation [ ] Sole Ownership [ ] Government [ ] Partnership [ ] Utility	
2. Owner's Name: GWF Energy LLC	
3. Agent to the Owner:	

II. COMPLIANCE CERTIFICATION (Read each statement carefully and initial all circles for confirmation):

MK Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).

MK Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.

MK Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.

MK Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

Mark Kehoe — 6/26/08

Signature of Responsible Official — Date

Mark Kehoe

Name of Responsible Official (please print)

Vice President, Environmental and Safety Programs

Title of Responsible Official (please print)

ATTACHMENT S

District Policy SSP 1105 – Emissions Monitoring for Boilers

San Joaquin Valley
Unified Air Pollution Control District

Emissions Monitoring for Rules 4305 and 4306

Approved By: ______________________________ David Warner Director of Permit Services	Date: April 28, 2008

Purpose: To identify pre-approved monitoring schemes that can be used as alternatives to continuous emissions monitoring systems (CEM's), and to establish procedures and criteria for case-by-case approval of other alternate monitoring proposals for compliance with Rule 4305, Boilers, Steam Generators, and Process Heaters - Phase II, and Rule 4306, Boilers, Steam Generators, and Process Heaters - Phase III. As an alternative to CEM's, an applicant may choose from the pre-approved monitoring schemes or may make a different alternate monitoring proposal for approval by the APCO. This policy identifies more than one pre-approved monitoring procedure for some control technologies. Applicants have the option of choosing the alternative most suitable to their needs.

An application for Authority to Construct must be submitted to the District in order to add or change monitoring permit conditions with the following exception: At permit renewal or by request from the Permittee, alternate monitoring permit conditions for a given scheme may be updated to current policy conditions for that same scheme.

I. Applicability

This policy applies to boilers, steam generators, and process heaters subject to District Rule 4305 and/or Rule 4306 that are subject to monitoring requirements of section 5.4 of these rules.

II. Background

Section 5.4.2 of both Rule 4305 and Rule 4306 requires that the owner of any unit subject to the emissions limits of the rules shall either install and maintain continuous emission monitoring equipment for NO_X, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install and maintain APCO-approved alternate monitoring consisting of one or more of the following:

- periodic NO_X and CO exhaust emission concentrations,
- periodic exhaust oxygen concentration,
- flow rate of reducing agent added to exhaust,
- catalyst inlet and exhaust temperature,

- catalyst inlet and exhaust oxygen concentration,
- periodic flue gas recirculation rate,
- other operational characteristics.

III. Guiding principles

The guiding principle of this policy in reference to section 5.4.2 of Rule 4305 and Rule 4306 is to establish monitoring procedures that provide a reasonable assurance of compliance with applicable emissions limits, while encouraging preventative maintenance and repair of emission systems. The primary goal is to ensure that a control technology, once installed or otherwise employed, is properly operated and maintained so that the control efficiency does not deteriorate to the point where the unit fails to remain in compliance with an applicable emission limit

An approvable monitoring procedure must (1) document continued operation within ranges of specified emissions-related performance indicators (such as emissions, control device parameters, and process parameters) that provide a reasonable assurance of compliance with applicable emission limits; (2) record and indicate any deviations from these ranges; and (3) require prompt response to any deviations either by correcting the deviations or by demonstrating compliance with applicable emissions limitations by further emissions testing.

If the equipment is found to be operating outside acceptable ranges for emission limits or emissions-related performance indicators, owners will be required to take prompt corrective actions to the equipment as well as notify the District that potential compliance problems may exist. Specific requirements for taking corrective action and notification are addressed in the individual monitoring procedures included in section VI of this policy.

Devising an approvable monitoring procedure requires a clear understanding of the pollutant formation mechanisms, the manner by which the control technology reduces emissions, and the parameters that contribute to the degradation of performance of the control technology. See Appendix A for discussion of NO_X formation mechanisms and control techniques.

Testing and engineering data may be needed to identify and establish acceptable ranges or levels of surrogate parameters that can serve as indicators of acceptable performance.

Many facilities that have boilers, steam generators, and heaters subject to the monitoring requirements of Rule 4305 and/or Rule 4306 are Title V sources. Although the monitoring requirements in this policy often meet Title V monitoring and recordkeeping requirements, the Title V permit may require additional monitoring not covered by this policy.

IV. Definitions

The following definitions are applicable to this policy:

A. **Normal Range or Level:** A range or a level for a surrogate parameter, based on source testing and engineering data, designed to provide a reasonable assurance of compliance with applicable emissions limits.

B. **Surrogate Parameter:** A parameter (such as a control device parameter, a process parameter, or exhaust gas emission concentration when measured with a portable analyzer) that can be used an indicator of the emission control system performance.

V. Compliance Issues

The surrogate parameters are seen as indicators that provide a reasonable assurance that the equipment or emission control system has been properly maintained and is operating in compliance with the applicable emission limits. However, excursions from normal ranges or levels for these surrogate parameters alone may not serve as credible evidence of the violation of an applicable emission limit. Such excursions place a burden on the owner to either correct the situation or conduct additional testing to verify compliance under the new operating conditions.

Therefore, as condition of approval for an alternate monitoring procedure in lieu of CEM's, the equipment operator must agree to take prompt corrective actions of excursions and document those actions. Excursions must be rectified within 1 hour of operation after detection unless source testing using an approved method to show compliance under the observed operating conditions is conducted within 60 days. Alternatively, if excursions are corrected after more than 1 hour of operation after detection and the permittee stipulates a violation has occurred, source testing will not be required. For excursions of surrogate parameters (excluding excursions of emission concentrations measured with a portable analyzer), a portable analyzer may be used to establish compliance with applicable emission limits at the new surrogate parameter values. For excursions of emission concentrations, compliance testing must follow EPA approved test methods. Where monitoring with a portable analyzer is allowed, testing using EPA approved methods can be substituted for testing with a portable analyzer. Retesting shall be performed under the same operational conditions that existed when the excursion was first detected.

Note: the procedures contained within this policy apply to monitoring performed by the permittee for the purpose of complying with the alternate monitoring requirements of Rule 4305 and/or Rule 4306. Monitoring performed by the District for compliance purposes cannot be used to satisfy permittee's alternate monitoring requirements. In addition, District performed monitoring for compliance purposes is not subject to this policy.

District Rule 1100, Equipment Breakdown, defines a breakdown and specifies the procedures to follow if a breakdown occurs. Should any excursion from normal ranges/levels for either emissions or surrogate parameters be detected, and the cause of such excursion can be traced to a viable breakdown condition as defined in Rule 1100, then the owner/operator may seek relief from enforcement action by fully complying with Rule 1100, including notification and immediate undertaking of appropriate corrective measures to come into compliance.

As with source testing, emissions monitoring with a portable analyzer shall be performed during normal operation, as specified in Rules 4305 and 4306 (Section 5.5.2).

For units that operate intermittently throughout the year, the units need not be started solely to perform monitoring required by this policy. Monitoring shall be performed within 5 days of restarting the units unless monitoring has been performed within the time period specified on the permit. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies allowed by this section.

Normal range or level for surrogate parameters shall be re-established at each scheduled source test. Should different ranges or levels be established, for non-Title V sources the Permit to Operate shall be revised administratively to reflect the new ranges or levels. For Title V sources, an application is required to change ranges or levels.

When a permittee switches from one alternate monitoring scheme to another (through an Authority to Construct), additional, out of schedule source testing to establish surrogate parameter ranges or levels shall not be required. Permittee may establish the ranges or levels using a portable analyzer, and re-establish the ranges or levels at the next scheduled source test.

Appendix B contains a flow chart detailing courses of action when an excursion is detected.

VI. Pre-Approved Alternate Monitoring Schemes

Alternate monitoring procedure that requires monitoring of the FGR valve(s), for units where the FGR valve position is continuously or intermittently varied in conjunction with the opening and closing of the fuel-throttling valve through linkage between the FGR valve and the fuel-throttling valve, shall not be allowed for any new boiler, steam generator, or heater or any existing boiler, steam generator, or heater changing alternate monitoring procedures. In addition, alternate monitoring procedure that requires monitoring of the FGR valve(s), for units where the FGR fan speed is continuously or intermittently varied, shall not be allowed for any new boiler, steam generator, or heater or any existing boiler, steam generator, or heater changing alternate monitoring procedures. Existing facilities may continue to use these procedures provided testing continues to show correlation between surrogate parameters and emissions.

The following alternate monitoring schemes have been approved as meeting the applicable provisions of Rule 4305 and Rule 4306: (When more than one alternate monitoring scheme is compatible with a given control technique, the applicant may select the option most suitable to their needs.)

A. Periodic Monitoring of NO_X, CO, and O_2 Concentrations

COMPATIBLE NO_X CONTROL TECHNIQUES: All units subject to the monitoring requirements of Rule 4305 and Rule 4306 will be allowed to monitor NO_X, CO, and O_2 concentrations.

FREQUENCY: Monitoring of NO_X, CO and O_2 shall be conducted at least once per month (in which a source test is not performed).

MEASUREMENT: The exhaust gas shall be monitored for NO_X, CO, and O_2 concentrations with a portable analyzer that meets District specifications. Performance specifications, calibration, and measurement techniques are listed in Section X of this policy.

RESULTS: NO_X and CO concentrations corrected to 3% O_2.

NORMAL RANGE OR LEVEL: NO_X and CO concentrations, corrected to 3% O_2, at or below the emissions limits specified in the permit.

REPORTING: If the equipment is operated outside the normal range or level for either NO_X or CO and the deviation is not corrected within 1 hour of operation after detection, the District shall be notified within the following 1 hour. Deviations corrected within 1 hour of operation after detection must only be recorded.

RECORDKEEPING: The date and time of measurement, and NO_X and CO concentrations (corrected to 3% O_2) shall be recorded. If any deviations from the normal range or level are observed, the types of corrective actions taken and the time and dates of such corrective action shall also be recorded. Records shall be kept onsite for a period of five years, and made available for inspection upon request.

B. Periodic Determination of FGR Rate by Temperature Measurement

C. Periodic Determination of FGR Rate by O_2 Measurement

COMPATIBLE NO_X CONTROL TECHNIQUES: Units with Flue Gas Recirculation (FGR), including units that use a low NO_X burner or conventional burners with off-stoichiometric combustion will be allowed to monitor flue gas recirculation rate.

FREQUENCY: Monitoring of the FGR rate shall be conducted at least once per week.

MEASUREMENT: The FGR rate is the amount of exhaust gas recycled to the combustion chamber divided by the fresh combustion air and recycled exhaust gas introduced into the burner. Two methods for determining the FGR rate are listed below (Depending on the flue gas recirculation method, other calculation methodologies may be more appropriate):

i) Temperature Measurement - The stack, windbox and ambient temperature readings can be used to calculate the FGR rate. (See Appendix C) [Only for units where flue gas and fresh air are mixed upstream of the burner.]

ii) O_2 Measurement - The stack and windbox O_2 readings can be used to calculate the FGR rate. (See Appendix D) [Only for units where flue gas and fresh air are mixed upstream of the burner.]

RESULTS: Flue gas recirculation rate

NORMAL RANGE OR LEVEL: Flue gas recirculation rate equal to or greater than the value established by testing of the unit or other representative units and specified on the permit. Normal range or level shall be re-established at each scheduled source test.

REPORTING: If the equipment is operated outside the normal range or level for the FGR rate and the deviation is not corrected within 1 hour of operation after detection, the District shall be notified within the following 1 hour. Deviations corrected within 1 hour of operation after detection must only be recorded.

RECORDKEEPING: The date and time of measurement, the temperature and/or O_2 level measured, the calculated FGR rate, and the firing rate shall be recorded. If any deviations from the normal range or level are observed, the types of corrective actions taken and the time and dates of such corrective action shall also be recorded. Records shall be kept onsite for a period of five years, and made available for inspection upon request.

D. Monitoring of Burner Mechanical Adjustments and O_2 Concentration

COMPATIBLE NOx CONTROL TECHNIQUES: Units which use staged air low NO_X burners will be allowed to monitor burner mechanical adjustments and exhaust gas O_2 concentration. Staged air low NO_x burners operate by limiting the oxygen availability in the primary combustion zone. This is done by setting the burner mechanical adjustments. Once the burner is adjusted it is not expected to change over time.

FREQUENCY: Monitoring of the exhaust gas O_2 concentration and visibly monitoring the mechanical burner linkages/adjustments shall be conducted at least once per week.

MEASUREMENT: The exhaust gas O_2 shall be measured with a portable analyzer or an in-stack analyzer that meets District specifications. Performance specifications, calibration, and measurement techniques are listed in Section XI of this policy. The applicant shall outline in writing the mechanical adjustments made to the burner. This should include a description of how these mechanical settings can be visibly inspected.

RESULTS: Exhaust gas O_2 concentration and settings for mechanical adjustments

NORMAL RANGE OR LEVEL: Exhaust gas O_2 concentration and settings for the burner mechanical adjustments within the ranges established by testing of the unit or other representative units and specified on the permit. Normal range or level shall be re-established at each scheduled source test.

REPORTING: If the equipment is operated outside the normal range or level for either the exhaust O_2 concentration or the burner mechanical settings and the deviation is not corrected within 1 hour of operation after detection, the District shall be notified within the following 1 hour. Deviations corrected within 1 hour of operation after detection must only be recorded.

RECORDKEEPING: The date and time of measurement, the O_2 level measured, and the burner's mechanical adjustment settings shall be recorded. If any deviations from the normal range or level are observed, the types of corrective actions taken and the time and dates of such corrective action shall also be recorded. Records shall be kept onsite for a period of five years, and made available for inspection upon request.

E. Monitoring of the FGR valve(s) setting

COMPATIBLE NO_X CONTROL TECHNIQUES: Units equipped with FGR where the FGR rate is set by one or more mechanical valve adjustments will be allowed to monitor the FGR valve(s) setting. Units where the FGR valve position is continuously or intermittently varied in conjunction with the opening and closing of the fuel-throttling valve through linkage between the FGR valve and the fuel-throttling valve are precluded from using this technique. In addition, units where the FGR fan speed is continuously or intermittently varied are also precluded from using this technique.

FREQUENCY: Monitoring of the FGR valve(s) setting shall be conducted at least once per week.

MEASUREMENT: The applicant shall outline in writing how the FGR valve(s) is/are mechanically set. The applicant shall also outline how the FGR valve(s) mechanical setting can be visibly inspected.

RESULTS: Mechanical setting for the FGR valve(s)

NORMAL RANGE OR LEVEL: FGR valve(s) mechanical setting equal to or greater (more FGR) than the value established by testing of the unit or other representative units and specified on the permit. Normal range or level shall be re-established at each scheduled source test.

REPORTING: If the equipment is operated outside the normal range or level for the FGR valve(s) mechanical setting and the deviation is not corrected within 1 hour of operation after detection, the District shall be notified within the following 1 hour. Deviations corrected within 1 hour of operation after detection must only be recorded.

RECORDKEEPING: The date and time of observation and the FGR valve(s)' mechanical settings shall be recorded. If any deviations from the normal range or level are observed, the types of corrective actions taken and the time and dates of such corrective action shall also be recorded. Records shall be kept onsite for a period of five years, and made available for inspection upon request.

F. Monitoring of the FGR fan variable frequency drive (VFD) output and fuel flow rate

COMPATIBLE NO_X CONTROL TECHNIQUES: Units equipped with forced FGR where the FGR rate is set by varying the FGR fan speed will be allowed to monitor the FGR fan VFD output. This type of FGR system uses a separate exhaust gas blower to recirculate the flue gas back into the flame for combustion. The VFD adjusts the speed of the FGR fan which then controls the FGR rate.

FREQUENCY: Monitoring of the FGR fan VFD hertz output, the natural gas firing rate, and the firing rate percentage value shall be conducted at least once per week.

MEASUREMENT: The FGR fan VFD hertz output shall be determined by reading the VFD display. The firing rate shall be obtained from the boiler display and is read in terms of percentage. Fuel flow (natural gas only) will be obtained from a dedicated fuel meter installed at the burner fuel train inlet of the boiler. The gas meter will indicate current ft^3/min flow and non-resettable totalized usage.

RESULTS: FGR fan VFD hertz output, the firing rate percentage, and the fuel flow in ft^3/min.

NORMAL RANGE OR LEVEL: The FGR fan VFD hertz output, the natural gas firing rate, and the firing rate percentage value equal to or greater (more FGR) than the value established by testing of the unit or other representative units and specified on the permit. Normal range or level shall be re-established at each scheduled source test.

REPORTING: If the equipment is operated outside the normal range or level for the FGR VFD hertz output and the deviation is not corrected within 1 hour of operation after detection, the District shall be notified within the following 1 hour. Deviations corrected within 1 hour of operation after detection must only be recorded.

RECORDKEEPING: The date and time of observation and the FGR fan hertz output, the firing rate percentage, and the fuel flow in ft^3/min shall be recorded. If any deviations from the normal range or level are observed, the types of corrective actions taken and the time and dates of such corrective action shall also be recorded. Records shall be kept onsite for a period of five years, and made available for inspection upon request.

G. Monitoring of the FGR fan speed and fuel flow rate

COMPATIBLE NO_X CONTROL TECHNIQUES: Units equipped with forced FGR where the FGR rate is set by varying the FGR fan speed will be allowed to monitor the FGR fan speed. This type of FGR system uses a separate exhaust gas blower to recirculate the flue gas back into the flame for combustion.

FREQUENCY: Monitoring of the FGR fan speed, the natural gas firing rate, and the firing rate percentage value shall be conducted at least once per week.

MEASUREMENT: The FGR fan speed shall be determined by reading the RPM speed meter. The firing rate shall be obtained from the boiler display and is read in terms of percentage. Fuel flow (natural gas only) will be obtained from a dedicated fuel meter installed at the burner fuel train inlet of the boiler. The gas meter will indicate current ft^3/min flow and non-resettable totalized usage.

RESULTS: FGR fan speed, the firing rate percentage, and the fuel flow in ft^3/min.

NORMAL RANGE OR LEVEL: The FGR fan speed, the natural gas firing rate, and the firing rate percentage value equal to or greater (more FGR) than the value established by testing of the unit or other representative units and specified on the permit. Normal range or level shall be re-established at each scheduled source test.

REPORTING: If the equipment is operated outside the normal range or level for the FGR fan speed and the deviation is not corrected within 1 hour of operation after detection, the District shall be notified within the following 1 hour. Deviations corrected within 1 hour of operation after detection must only be recorded.

RECORDKEEPING: The date and time of observation and the FGR fan speed, the firing rate percentage, and the fuel flow in ft^3/min shall be recorded. If any deviations from the normal range or level are observed, the types of corrective actions taken and the time and dates of such corrective action shall also be recorded. Records shall be kept onsite for a period of five years, and made available for inspection upon request.

H. Periodic monitoring of NO_X, CO, O_2, and ammonia slip emissions concentrations for units equipped with selective catalytic reduction (SCR)

COMPATIBLE NO_X CONTROL TECHNIQUES: Units equipped with SCR which utilize a catalytic bed and a reducing agent, usually ammonia, to convert NO_X to nitrogen and oxygen will be allowed to monitor NO_X, CO, O_2 and ammonia. For units equipped with SCR ammonia is injected into the exhaust system up stream of a catalyst which creates a reducing atmosphere. The exhaust stream then passes through a catalyst, which promotes the reduction reaction. The reduction reaction results in nitrogen oxide being converted to nitrogen and oxygen.

FREQUENCY: Monitoring of NO_X, CO, O_2 and ammonia readings shall be conducted at least once per month (in which a source test is not performed).

MEASUREMENT: The exhaust gas shall be monitored for NO_X, CO, and O_2 concentrations with a portable analyzer that meets District specifications. Performance specifications, calibration, and measurement techniques are listed in Section X of this policy. In addition, the exhaust gas shall be monitored for ammonia concentration with gas detection tubes (Dräger® brand or District approved equivalent).

RESULTS: NO_X, CO, and ammonia concentrations corrected to 3% O_2.

NORMAL RANGE OR LEVEL: NO_X, CO, and ammonia concentrations, corrected to 3% O_2, at or below the emissions limits specified in the permit.

REPORTING: If the equipment is operated outside the normal range or level for NO_X, CO, and ammonia and the deviation is not corrected within 1 hour of operation after detection, the District shall be notified within the following 1 hour. Deviations corrected within 1 hour of operation after detection must only be recorded.

RECORDKEEPING: The date and time of measurement, and NO_X, CO, and ammonia concentrations (corrected to 3% O_2) shall be recorded. If any deviations from the normal range or level are observed, the types of corrective actions taken and the time and dates of such corrective action shall also be recorded. Records shall be kept onsite for a period of five years, and made available for inspection upon request.

VII. Pre-Approved Monitoring Procedures for Units Without NO_X Reduction Technology

With respect to monitoring, the current versions of Rules 4305 and 4306 do not differentiate between units equipped with NO_X reduction technology versus those without NO_X reduction technology. All units subject to section 5.4 of these rules must utilize the same degree of monitoring.

VIII. Case-By-Case Approvals of Other Alternate Monitoring Procedures

The permittee may seek a case-by-case approval of monitoring procedures other than those pre-approved above. The applicant must provide a technical justification and demonstrate that the parameters to be monitored have a strong correlation with NO_X and CO emissions, and will provide a reasonable assurance of compliance. Monitoring proposals are to be submitted to the Director of Permit Services for approval. (Once Director approval is granted for a monitoring procedure, the evaluation and the associated documents must be distributed to the other regional offices and posted to the District's intranet site. Subsequent approval of identical proposals may be made by the Regional Permit Services Manager.) Monitoring proposal should contain information on the following:

A. Control technology - This should include specific details about the how the control technology operates and how NO_X reduction occurs.

B. Monitored Parameters - This should describe the correlation between the proposed monitoring parameters and NO_X emissions.

C. Measurement - This should include the specifics of the proposed measuring equipment and the location(s) of the equipment.

D. Frequency - This should include a justification showing that the frequency of monitoring proposed is sufficient to show ongoing compliance.

E. Results -The permit must contain an enforceable condition specifying the acceptable range of values for all parameters to be monitored. For units equipped with NO_X reduction technology, the range(s) may be established by source testing of the unit or through source test data for other units determined by the APCO to be applicable to the unit. For units not equipped with NO_X reduction technology, the range(s) may be obtained from the equipment manufacturer or control system supplier, or by source testing of the unit.

IX. Permit Terms and Conditions

The permit must outline the facility's approach to monitoring and the manner by which a normal range/level for surrogate parameters is established. The permit must also include requirements for adequate recordkeeping and reporting, prompt notification and correction of excursions from the normal range of operations.

The following general conditions must be incorporated in permits for which alternate monitoring is allowed:

A. Periodic Monitoring of NO_X, CO, And O_2 Emission Concentrations

1. {4063} The permittee shall monitor and record the stack concentration of NO_X, CO, and O2 at least once every month (in which a source test is not performed) using a portable analyzer that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305 and 4306]

2. {4064} If either the NO_X or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305 and 4306]

3. {4065} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken 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. [District Rules 4305 and 4306]

4. {4066} The permittee shall maintain records of: (1) the date and time of NO_X, CO, and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOX and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305 and 4306]

B. Periodic Determination of Flue Gas Recirculation Rate Using Temperature Measurements

1. {4067} The flue gas recirculation rate shall be determined at least on a weekly basis by measuring the stack temperature (Ts), windbox temperature (Tw), and ambient temperature (Ta) and using the following equation: FGR rate = {Tw - Ta)/(Ts - Ta)} x 100%. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last week. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 4305 and 4306]

2a. {4068} The minimum flue gas recirculation rate shall be established by source testing this unit or other representative units per Rules 4305 and 4306 and as approved by the District. The normal range/level shall be no lower than the minimum flue gas recirculation rate with which compliance with applicable NOX and CO emission limits has been demonstrated through source testing at a similar firing rate. [District Rules 4305 and 4306]

The above condition should be changed to the following upon conversion of the Authority to Construct to a Permit to Operate:

2b. The flue gas recirculation rate shall not be less than XX% at firing rates less than XX%. The flue gas recirculation rate shall not be less than XX% at firing rates greater than XX% and less than XX%. The flue gas recirculation rate shall not be less than XX% at firing rates greater than XX%. [District Rules 4305 and 4306]

3. {4069} Normal range or level for the flue gas recirculation rate shall be re-established during each source test required by this permit. [District Rules 4305 and 4306]

4. {4070} If the flue gas recirculation rate is less than the normal range/level, the permittee shall return the flue gas recirculation rate to the normal range/level as soon as possible, but no longer than 1 hour of operation after detection. If the flue gas recirculation rate is not returned to the normal range/level within 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour, and conduct a source test within 60 days of the first exceedance, to demonstrate compliance with the applicable emission limits at the new flue gas recirculation rate. A District-approved portable analyzer may be used in lieu of a source test to demonstrate compliance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305 and 4306]

5. {4071} The permittee shall maintain records of the date and time of temperature measurements, the measured temperatures, the calculated flue gas recirculation rate, and the firing rate at the time of the temperature measurements. The records shall also include a description of any corrective action taken to maintain the flue gas recirculation rate within the acceptable range. [District Rules 4305 and 4306]

C. Periodic Determination of Flue Gas Recirculation Rate Using O_2 Measurements

1. {4072} The flue gas recirculation rate shall be determined at least on a weekly basis by measuring the stack O2% by volume (Os), and windbox O2% by volume (Ow) using the following equation: FGR rate = {Ow - 20.9)/(Os - 20.9)} x 100%. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last week. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 4305 and 4306]

2a. {4068} The minimum flue gas recirculation rate shall be established by source testing this unit or other representative units per Rules 4305 and 4306 and as approved by the District. The normal range/level shall be no lower than the minimum flue gas recirculation rate with which compliance with applicable NOX and CO emission limits has been demonstrated through source testing at a similar firing rate. [District Rules 4305 and 4306]

The above condition should be changed to the following upon conversion of the Authority to Construct to a Permit to Operate:

2b. The flue gas recirculation rate shall not be less than XX% at firing rates less than XX%. The flue gas recirculation rate shall not be less than XX% at firing rates greater than XX% and less than XX%. The flue gas recirculation rate shall not be less than XX% at firing rates greater than XX%. [District Rules 4305 and 4306]

3. {4069} Normal range or level for the flue gas recirculation rate shall be re-established during each source test required by this permit. [District Rules 4305 and 4306]

4. {4073} If the flue gas recirculation rate is less than the normal range/level, the permittee shall return the flue gas recirculation rate to the normal range/level as soon as possible, but no longer than 1 hour of operation after detection. If the flue gas recirculation rate is not returned to the normal range/level within 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance, to demonstrate compliance with the applicable emission limits at the new flue gas recirculation rate. A District-approved portable analyzer may be used in lieu of a source test to demonstrate compliance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305 and 4306]

5. {4074} The permittee shall maintain records of the date and time of oxygen concentration measurements, the measured oxygen concentrations, the calculated flue gas recirculation rate, and the firing rate at the time of the oxygen concentration measurements. The records shall also include a description of any corrective action taken to maintain the flue gas recirculation rate within the acceptable range. [District Rules 4305 and 4306]

D. Monitoring of Burner Mechanical Adjustments and O_2 Concentration

1. The stack O2 concentration measurement and inspection of [LIST MECHANICAL ADJUSTMENTS/SETTINGS] shall be conducted at least on a weekly basis. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last week. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 4305 and 4306]

2a. {4076} The normal range/level of stack O2 concentration and visible mechanical burner settings shall be established by source testing this unit or other representative units per Rules 4305 and 4306 and as approved by the District. The normal range/level shall be that for which compliance with applicable NOX and CO emission limits has been demonstrated through source testing at a similar firing rate. [District Rules 4305 and 4306]

The above condition should be changed to the following upon conversion of the Authority to Construct to a Permit to Operate:

2b. The stack O_2 concentration shall maintained between X% and X% at firing rates less than XX%. The stack O_2 concentration shall maintained between X% and X% at firing rates greater than XX% and less than XX%. The stack O_2 concentration shall maintained between X% and X% at firing rates greater than XX%. [District Rules 4305 and 4306]

2c. The burner mechanical settings shall be maintained at [*describe settings at which compliance was demonstrated at the initial source test*]. [District Rules 4305 and 4306]

3. {4077} Normal range or level for the stack O2 concentration and burner mechanical settings shall be re-established during each source test required by this permit. [District Rules 4305 and 4306]

4. {4078} If the either the stack O2 concentration or visible mechanical burner settings are less than the normal range/level, the permittee shall return the stack O2 concentration and visible mechanical burner settings to the normal range/level as soon as possible, but no longer than 1 hour of operation after detection. If the stack O2 concentration and visible mechanical burner settings are not returned to the normal range/level within 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour, and conduct a source test within 60 days of the first exceedance, to demonstrate compliance with the applicable emission limits at the new stack O2 concentration and visible mechanical burner settings. A District-approved portable analyzer may be used in lieu of a source test to demonstrate compliance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305 and 4306]

5. {4079} The permittee shall maintain records of the date and time of O2 measurements and burner adjustments, the measured O2 concentrations (% by volume) and firing rate at the time of O2 measurement, and the observed setting for [LIST ADJUSTMENTS TO INSPECTED]. The records must also include a description of any corrective action taken to maintain the O2 concentration and the burner mechanical settings within the acceptable range. [District Rules 4305 and 4306]

E. Monitoring of the FGR valve(s) setting

1. {4080} The flue gas recirculation valve(s) setting shall be monitored at least on a weekly basis. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last week. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 4305 and 4306]

2a. {4081} The acceptable settings for the flue gas recirculation valve(s) shall be established by source testing this unit or other representative units per Rules 4305 and 4306 and as approved by the District. The normal range/level shall be that for which compliance with applicable NOx and CO emissions rates have been demonstrated through source testing at a similar firing rate. [District Rules 4305 and 4306]

The above condition should be changed to the following upon conversion of the Authority to Construct to a Permit to Operate:

2b. The flue gas recirculation valve(s) setting shall not be less than [*describe valve(s) setting at which compliance was demonstrated at the initial source test*] at firing rates less than XX%. The flue gas recirculation valve(s) setting shall not be less than [*describe valve(s) settings at which compliance was demonstrated at the initial source test*] at firing rates greater than XX% and less than XX%. The flue gas recirculation valve(s) setting shall not be less than [*describe valve(s) settings at which compliance was demonstrated at the initial source test*] at firing rates greater than XX%. [District Rules 4305 and 4306]

3. {4082} Normal range or level for the flue gas recirculation valve(s) settings shall be re-established during each source test required by this permit. [District Rules 4305 and 4306]

4. {4083} If the flue gas recirculation valve(s) setting is less than the normal range/level, the permittee shall return the flue gas recirculation valve(s) setting to the normal range/level as soon as possible, but no longer than 1 hour of operation after detection. If the flue gas recirculation valve(s) setting is not returned to the normal range/level within 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour, and conduct a source test within 60 days of the first exceedance, to demonstrate compliance with the applicable emission limits at the new flue gas recirculation valve(s) setting. A District-approved portable analyzer may be used in lieu of a source test to demonstrate compliance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305 and 4306]

5. {4084} The permittee shall maintain records of the date and time of flue gas recirculation valve(s) settings, the observed setting, and the firing rate at the time of the flue gas recirculation valve(s) setting measurements. The records must also include a description of any corrective action taken to maintain the flue gas recirculation valve(s) setting within the acceptable range. [District Rules 4305 and 4306]

F. Monitoring of the FGR fan VFD output

1. {4085} The boiler shall be equipped with displays for monitoring the flue gas recirculation (FGR) fan variable frequency drive (VFD) hertz output, the natural gas firing rate in raw cubic feet per minute, and the firing rate percentage value. [District Rules 4305 and 4306]

2a. {4086} The normal range or level of FGR fan VFD output value shall be established by testing emissions from this unit or other representative units as approved by the District. The normal range/level shall be those for which compliance with applicable NOx and CO emission rates have been demonstrated through source testing at a similar firing rate. [District Rules 4305 and 4306]

The above condition should be changed to the following upon conversion of the Authority to Construct to a Permit to Operate:

2b. The FGR fan VFD output value shall not be less than XX.X Hz at firing rates less than XX%. The FGR fan VFD output value shall not be less than XX.X Hz at firing rates equal to or greater than XX% and less than XX%. The FGR fan VFD output value shall not be less than XX.X Hz at firing rates equal to or greater than XX% and less than XX%. The FGR fan VFD output value shall not be less than XX.X Hz at firing rates equal to or greater than XX%. [District Rules 4305 and 4306]

3. {4087} The normal range or level for the FGR fan VFD output value shall be re-established during each source test required by this permit. [District Rules 4305 and 4306]

4. {4088} The FGR fan VFD hertz output, the natural gas firing rate in raw cubic feet per minute, the date and time the test was conducted, and the firing rate percentage value as indicated by the variable frequency controllers will be taken for each test rate shall be inspected on at least a weekly basis. [District Rules 4305 and 4306]

5. {4089} The permittee shall maintain records of the FGR fan VFD hertz output, the natural gas firing rate in raw cubic feet per minute, the date and time the test was conducted, and the firing rate percentage value. The records must also include a description of any corrective action taken to maintain the FGR fan VFD output above the minimum acceptable rate. These records shall be retained at the facility for a period of no less than five years and shall be made available for District inspection upon request. [District Rules 4305 and 4306]

6. {4090} If the FGR fan VFD output deviates from the acceptable range/level for more than one hour, the permittee shall notify the District and take corrective action within one (1) hour after detection. If the FGR fan VFD output is not corrected within one hour, the permittee shall conduct an emissions test within 60 days, utilizing District-approved test methods, to demonstrate compliance with the applicable emissions limits at observed the FGR fan VFD output value. [District Rules 4305 and 4306]

G. Monitoring of the FGR fan speed

1. {4091} The boiler shall be equipped with displays for monitoring the flue gas recirculation (FGR) fan speed, the natural gas firing rate in raw cubic feet per minute, and the firing rate percentage value. [District Rules 4305 and 4306]

2a. {4092} The normal range or level of FGR fan speed shall be established by testing emissions from this unit or other representative units as approved by the District. The normal range/level shall be those for which compliance with applicable NOx and CO emission rates have been demonstrated through source testing at a similar firing rate. [District Rules 4305 and 4306]

The above condition should be changed to the following upon conversion of the Authority to Construct to a Permit to Operate:

2b. The FGR fan speed shall not be less than XXX rpm at firing rates less than XX%. The FGR fan speed shall not be less than XXX rpm at firing rates equal to or greater than XX% and less than XX%. The fan speed shall not be less than XXX rpm at firing rates equal to or greater than XX% and less than XX%. The FGR fan speed shall not be less than XXX rpm at firing rates equal to or greater than XX%. [District Rules 4305 and 4306]

3. {4093} Normal range or level for the FGR fan speed shall be re-established during each source test required by this permit. [District Rules 4305 and 4306]

4. {4094} The FGR fan speed, the natural gas firing rate in raw cubic feet per minute, the date and time the test was conducted, and the firing rate percentage value will be taken for each test rate shall be inspected on at least a weekly basis. [District Rules 4305 and 4306]

5. {4095} The permittee shall maintain records of the FGR fan speed, the natural gas firing rate in raw cubic feet per minute, the date and time the test was conducted, and the firing rate percentage value. The records must also include a description of any corrective action taken to maintain the FGR fan speed above the minimum acceptable rate. These records shall be retained at the facility for a period of no less than five years and shall be made available for District inspection upon request. [District Rules 4305 and 4306]

6. {4096} If the FGR fan speed deviates from the acceptable range/level for more than one hour, the permittee shall notify the District and take corrective action within one (1) hour after detection. If the FGR fan speed is not corrected within one hour, the permittee shall conduct an emissions test within 60 days, utilizing District-approved test methods, to demonstrate compliance with the applicable emissions limits at observed the FGR fan speed. [District Rules 4305 and 4306]

H. Periodic monitoring of NO_X, CO, O_2, and ammonia slip emissions concentrations for units equipped with SCR

1. {4097} The permittee shall monitor and record the stack concentration of NOx, CO, NH3 and O2 at least once during each month in which source testing is not performed. NOx, CO and O2 monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH3 monitoring shall be conducted utilizing gas detection tubes (Draeger brand or District approved equivalent). Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless it has been performed within the last month. [District Rules 4305 and 4306]

2. {4098} If either the NOx, CO or NH3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305 and 4306]

3. {4099} All NOx, CO, O2 and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NOx, CO and O2 analyzer as well as the NH3 emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken 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 readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305 and 4306]

4. {4100} Ammonia emissions readings shall be conducted at the time the NOx, CO and O2 readings are taken. The readings shall be converted to ppmvd @ 3% O2. [District Rules 4305 and 4306]

5. {4101} The permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx, CO and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 4305 and 4306]

X. Approvable Portable Analyzer

A. General

A portable analyzer consists of a sample interface, a gas detector, and a data recorder and is used to quantitatively analyze stack gas for one or more components. A portable analyzer for CO, O_2, or NO_X shall be considered approved by the District if it adheres to the standards that are set forth in this section, is used in accordance with the standards of this section, and is used in accordance with the manufacturer's specifications. Other portable analyzers and techniques may be approved on a case-by-case basis. It is important to note that portable analyzers may be hand-held, or mounted in a motor vehicle.

1. **Sample interface:** That portion of the portable analyzer used for one or more of the following: sample acquisition, sample transport, sample conditioning, or protection of the portable analyzer from the effects of the stack effluent.

2. **Gas detector:** That portion of the portable analyzer that senses the gas to be measured and generates an output proportional to the gas concentration.

3. **Data recorder:** A strip chart recorder, digital recorder, or any other device used for recording or displaying measurement data from the gas detector output.

4. **Resolution:** The smallest increment of output that the gas detector will provide. This value should be available from the equipment manufacturer.

5. **Error:** The maximum standard measurement error over the measurement range. This value should be available from the equipment manufacturer.

6. **Response Time:** The amount of time required for the portable analyze display 95% of a change in gas concentration on the data recorder. This value should be available from the equipment manufacturer.

B. Equipment

The portable analyzer shall adhere to the standards tabulated below for each of the pollutants and O_2 that it is intended to measure. All values in the table refer to maximum values. In addition to the parameters contained in the table, the minimum upper limit of the measurement range shall be equal to 1.5 times the emission limit for the species being measured.

Detector	Resolution	Error	Maximum Response Time
CO	high 20 ppm low 2 ppm	± 5%	1 min
O_2	0.1%	larger of ± 4% of reading or 0.2% O_2	1 min
NO_X	2 ppm	± 5%	1 min

C. Calibration

Periodic calibration of the portable analyzer is vital to ensure readings obtained are as accurate as possible, and to provide the most benefit to a periodic monitoring program. Inaccurate analyzer data will result in delays in recognizing pending emission control equipment failure, if the emission readings are too low. Or, if the readings are too high, inaccurate data will result in needless expenditure of time searching for problems that do not exist. Calibration frequency must be frequent enough to allow the permittee to recognize excursions and bring the emission unit back into allowed ranges before violations are detected by the District. **Sources should consider checking their units with proper calibration gases between calibrations to insure their continued accuracy.**

Therefore, each gas detector shall be calibrated according to the manufacturer's guidelines and at the manufacturer's recommended frequency with EPA Protocol or Primary Standard calibration gases. A copy of the manufacturer's recommended calibration frequency must be kept with these records.

The system response time shall be determined during the gas detector calibration. The portable analyzer shall first be purged with ambient air. Calibration gas is then provided to the portable analyzer through a tubing length and diameter typically used during analysis. The length and diameter of tubing used during calibration shall be included with the calibration records. The time necessary for the data recorder to display a concentration equal to 95% of the final steady state concentration shall be recorded as the response time.

D. Measurement

1. Except for oilfield steam generators and heater treaters, the sampling port must be located at a point equal to the length of two stack diameters downstream of any disturbance and at a point equal to the length of one-half of the stack diameter upstream of any disturbance or outlet.

The sampling port opening around the sampling probe must be thoroughly sealed to prevent air and exhaust leaks that will cause a dilution to the gas stream.

2. Except for oilfield steam generators and heater treaters, before initiating an emission concentration measurement program, the exhaust flow in the stack must be checked for stratification by sampling 3 different locations within the same plane across the stack for at least one minute each. If the emission concentration values differ by more than 10% from the mean, then each location of the stack shall be sampled as described in #3a below. The results obtained in #3a below for each location shall then be averaged and recorded as the final value. The permit holder shall record and maintain documentation verifying the presence or absence of stratification and make such documentation available upon request. Once stratification has been established to exist or not exist, the following measurements may be taken according to #3 or #3a below, respectively, provided records of stratification testing are retained, no physical or operational changes are made to the unit, and no physical changes are made to the stack. In no situations shall sampling be performed with the sample acquisition probe located at or near the wall of the stack.

   Oil field steam generators may sample through the convection section sight glass or sample port located nearby.

   All stack outlets of oil field heater treaters must be tested. Each outlet test must include the following:

      The sample must be drawn from within a central area in the stack and at least one full stack diameter upstream of the outlet.

      The results from each outlet must be calculated and reported separately (do not average the ppmv concentrations or the lb/MMBtu emission rates).

3. Emission concentration measurement shall be initiated by exposing the sample acquisition probe to the stack gas. 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. After 1 minute (or after the reading stabilizes, whichever is earlier), the 15 consecutive minute period shall begin. For heater treaters where the firing rate varies significantly as part of normal operation, a single 15

consecutive-minute period shall be used. Such period shall include at least one firing rate ramp-up and one firing rate ramp-down sequence.

a. If stratification was determined to exist at greater than 10% of the emission concentration as described in #1 above, then a cumulative 15 minute sample at a single point in the stack cannot be used. Emission readings must be taken using at least five (5) readings, evenly spaced out over the 15 consecutive-minute period, with at least one reading taken at each of the 3 locations in the stack determined in #1 above. The results shall then be averaged and recorded as the final value.

4. If water vapor is not removed prior to measurement, the absolute humidity in the gas stream must be determined so that the gas concentrations may be reported on a dry basis. If water vapor creates an interference with the measurement of any component, then the water vapor must be removed from the gas stream prior to concentration measurements.

5. The concentration of NO_X is calculated as the sum of the volumetric concentrations of both NO and NO_2. The portable analyzer used to detect NO_X must either convert NO_2 to NO and measure NO, convert NO to NO_2 and measure NO_2, or measure both NO and NO_2. An NO_2 to NO converter is not necessary if data are presented to demonstrate that the NO_2 portion of the exhaust gas is less than 5 percent of the total NO_X concentration.

APPENDIX A

External Combustion NO_X Formation Mechanisms and Control Techniques

I. NO_X Formation Mechanisms

A. Thermal NO_X:

In fossil fuel combustion, O_2 and N_2 combine to form nitric oxide (NO) and nitrogen dioxide (NO_2) in the high temperature zones in the burner flame. The main factors affecting the quantity of NO_X formed by thermal fixation are (1) the flame temperature, (2) the residence time of the combustion gases in the peak temperature zone, and (3) the amount of oxygen present in the peak temperature zone. This is the primary NO_X formation mechanism for natural gas fired combustion equipment.

B. Fuel NO_X:

In fossil fuel combustion, fuel bound nitrogen can react with O_2 to form NO_X emissions. The rate of NO_X formation due to fuel nitrogen converted is dependent upon the amount of nitrogen contained in the fuel, oxygen concentration present in the flame and the mixing rate of the fuel and air. Most natural gas contains no fuel bound nitrogen.

C. Prompt NO_X:

In fossil fuel combustion, NO_X can also form due to the reaction of molecular nitrogen with free radicals such as HCN, NH, and N present in the burner flame. These reactions are not related to the peak flame temperature. Therefore, combustion modifications do not have a strong influence on the NO_X formed by this mechanism.

II. NO_X Control Techniques

A. Low Excess Air Operation

Operating with low excess air reduces the O_2 concentration in the peak temperature zone. This inhibits the reactions responsible for both thermal and fuel bound NO_X. Low excess air operation is generally used in conjunction with other NO_X control techniques. Low excess air operation is usually accomplished through the use of an O_2 analyzer/controller.

B. Conventional Burner with Off-Stoichiometric Combustion (Staged Combustion)

Combustion of the fuel is carried out in two stages. The first stage is a fuel rich zone in the region of the primary flame. The second stage is an air rich zone that completes the combustion of the fuel. Staging the combustion results in lower NO_X emissions by 1) limiting available O_2 for NO_X formation in the fuel rich primary stage, 2) lowering flame temperature in the fuel rich primary stage, and 3) flame temperature is lower in the air rich secondary stage. Common off-stoichiometric combustion systems in conventional burners are listed below:

1. **Overfire Air Ports (OFA)**

Separate air injection nozzles are located above the burner(s). The burner(s) are operated fuel rich and the overfire air ports maintain the rest of the combustion.

2. **Biased Firing**

In boilers with multiple burners, some burners are operated fuel rich while other burners are operated air rich in a staggered configuration.

3. **Burners Out of Service**

In boilers with multiple burners, some burners are operated fuel rich while other burners are not fired but provide combustion air only.

C. Flue Gas Recirculation (FGR)

A portion of the exhaust gas stream is recycled back into the main combustion zone by extracting it from the exhaust and mixing it with the combustion air or the combustion air/fuel mixture. This reduces thermal NO_X formation by reducing the peak temperature and by diluting the oxygen content in the combustion zone. The two types of FGR systems are forced draft and induced draft. Forced draft systems use a separate exhaust gas blower to recirculate the flue gas. Induced draft systems use the primary combustion blower to recirculate the flue gas. In both systems the primary combustion air and the recycled exhaust gas are typically mixed in the windbox. As the FGR rate increases, the amount of NO_X produced decreases.

D. Low NO_X Burner

Low NO_X burners control mixing of fuel and air in a pattern that keeps flame temperature low and dissipates the heat quickly. Low NO_X burners incorporate many design principles to achieve low NO_X operation. Some low NO_X burners use multiple design principles. The design principles are listed below.

1. **Staged Air Burners**

Staged air burners operate with a fuel rich primary zone and air rich secondary zone (off-stoichiometric combustion). The fuel rich primary zone reduces the O_2 available for NO_X formation and can lower combustion temperatures in both zones.

2. **Staged Fuel Burners**

The fuel is added in stages. The first stage is an oxygen rich, fuel lean stage in which the peak zone temperature is reduced. The second stage is a fuel rich, oxygen lean stage that carries out the combustion. Lower flame temperature reduces the formation of thermal NO_X.

3. Pre-Mix Burners

Fuel and air are pre-mixed prior to introduction into the burner. Good mixing allows complete combustion to take place with less excess air. Operating with low excess air reduces the O_2 concentration in the peak temperature zone. This inhibits the sets of reactions responsible for both thermal and fuel bound NO_X formation.

4. Internal Recirculation

Burner geometry induces combustion gases to recirculate in the combustion zone. This reduces NO_X formation by reducing the flame temperature and diluting the oxygen content in the peak temperature zone similar to FGR.

5. Radiant Burners

Radiant burners have an incandescent surface that transfers heat as radiant energy from the burner to the heat exchanger walls. The burner consists of a porous ceramic fiber matrix. Pre-mixed gas and air are forced through the openings in the ceramic fiber matrix. Once ignition occurs, combustion stabilizes on the outer surface of the ceramic burner. The burner operates at a lower temperature than conventional burners. The low burner temperature reduces the formation of thermal NO_X.

E. Flue Gas Treatment

NO_X can be reduced to molecular nitrogen by adding flue gas treatment systems located after the boiler firebox. The two basic system types are listed below:

1. Selective Noncatalytic Reduction

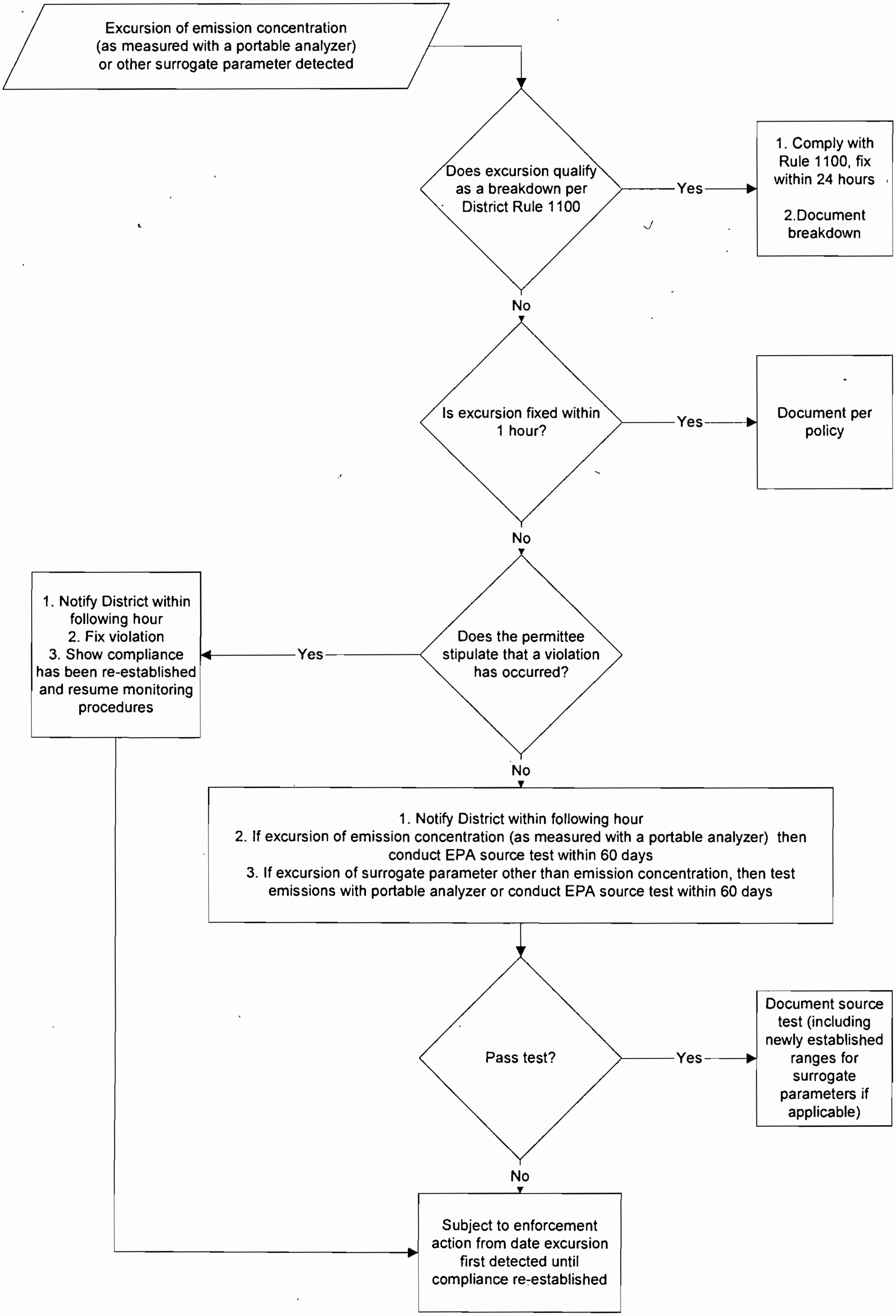
Ammonia (NH_3) or urea (NH_2CONH_2) is injected into the post combustion zone of the boiler. The ammonia/urea reacts with the NO_X formed during combustion to form molecular nitrogen and water. This reaction is largely dependent upon temperature. The reaction only occurs at temperatures between 1600° F and 2000° F. At temperatures above 2000° F the nitrogen in the ammonia/urea is oxidized to produce NO_X. At temperatures below 1600° F the ammonia/urea passes through unreacted. Due to the temperature dependence of the reaction the location of the ammonia/urea injectors is critical. The optimum injection point changes with boiler load. Due to this fact most SNCR systems have two sets of injection points. The ratio of the ammonia/urea concentration to the NO_X concentration is an important parameter. Injection of ammonia/urea at a higher stoichiometric ratio increases NO_X conversion efficiency but also increases ammonia/urea slip.

2. Selective Catalytic Reduction (SCR)

Ammonia is injected through a series of nozzles arranged in a grid to facilitate uniform mixing prior to a catalyst bed. The ammonia reduces the NO_X on the catalyst surface. The operating range for SCR catalysts is typically 550° F to 750° F. Any particular SCR catalyst has a narrow temperature window for optimum operation. Variations in exhaust gas temperature of 50° F can have an impact on NO_X reduction efficiency. There are a variety of problems that can affect catalyst bed performance. Phosphorus, lead and arsenic can irreversibly poison the catalyst material. The catalyst can also be masked by chemicals or particulate adsorbing to the surface. The ratio of the ammonia concentration to the NO_X concentration is critical. Injection of ammonia at a higher stoichiometric ratio increases NO_X conversion efficiency but also increases ammonia slip. The ammonia injection grid must also uniformly mix and atomize the ammonia.

APPENDIX B

Excursion Flow Chart



Excursion of emission concentration (as measured with a portable analyzer) or other surrogate parameter detected
Does excursion qualify as a breakdown per District Rule 1100
Yes
1. Comply with Rule 1100, fix within 24 hours
2.Document breakdown
No
Is excursion fixed within 1 hour?
Yes
Document per policy
No
Does the permittee stipulate that a violation has occurred?
Yes
1. Notify District within following hour
2. Fix violation
3. Show compliance has been re-established and resume monitoring procedures
No
1. Notify District within following hour
2. If excursion of emission concentration (as measured with a portable analyzer) then conduct EPA source test within 60 days
3. If excursion of surrogate parameter other than emission concentration, then test emissions with portable analyzer or conduct EPA source test within 60 days
Pass test?
Yes
Document source test (including newly established ranges for surrogate parameters if applicable)
No
Subject to enforcement action from date excursion first detected until compliance re-established

APPENDIX C

Computation of FGR Rate Using Temperatures

Computation of FGR Rate Using Temperature

The theory behind the determination of the flue gas recirculation rate using temperature observation is conservation of energy. The heat content of the mixed combustion air is the sum of the heat contained in the recirculated flue gas and the heat contained in the fresh combustion air. This simplified analysis assume the heat carrying capacity per unit mass (c_p) of the fresh combustion air, the recirculated flue gas, and the combined combustion air is the same. For the temperatures, pressures, and gases involved this assumption introduces insignificant error. The largest potential source of error is that the combined combustion air temperature measured may not be the final equilibrium temperature of the mixture. If this occurs, this procedure will compute flue gas recirculation rates lower than actual. However, provided the temperatures are always measured at the same locations, the relative amount of flue gas recirculated may be ascertained.

define FGR rate as the amount of flue gas recirculated divided by combustion air supplied to the firebox (which is the sum of the fresh air provided and the flue gas recirculated):

1. FGR = amt. recirculated / (amt. fresh + amt. recirculated)

from conservation of energy at constant specific heat (c_p):

2. (amt. fresh x T_{fresh}) + (amt. recirc. x T_{recirc}) = (amt. fresh + amt. recirc.) x (T_{comb})
   (amt. fresh x T_{fresh}) + (amt. recirc. x T_{recirc}) = (amt. fresh) x T_{comb}+ (amt. recirc.) x T_{comb}

combining terms and re-arranging:

(amt. recirc) x (T_{recirc} - T_{comb}) = (amt. fresh) x (T_{comb} -Tfresh)
amt. recirc = (amt. fresh) x [(T_{comb} - T_{fresh}) / (T_{recirc} - T_{comb})]

substituting in equation 1:

$$FGR = \frac{(\text{amt. fresh}) \times [(T_{comb} - T_{fresh}) / (T_{recirc} - T_{comb})]}{(\text{amt. fresh}) + (\text{amt. fresh}) \times [(T_{comb} - T_{fresh}) / (T_{recirc} - T_{comb})]}$$

canceling the like terms "(amt. fresh)", substituting the identity "(T_{recirc} -T_{comb})/(T_{recirc}-T_{comb})" for the "1" in the denominator and canceling the like terms "(T_{recirc} - T_{comb})" yields:

FGR = (T_{comb} - T_{fresh}) / (T_{recirc} - T_{fresh})

APPENDIX D

Computation of FGR Rate Using Oxygen Measurements

Computation of FGR Rate Using Oxygen Measurements

The theory behind the determination of the flue gas recirculation rate using oxygen concentration observations is conservation of species. The amount of oxygen in the mixed combustion air flue gas is the sum of the oxygen contained in the recirculated flue gas and the oxygen contained in the fresh combustion air. The largest potential source of error is that the combined combustion air oxygen measurement may not reflect a complete (or perfect) mixture. If so, this procedure will compute flue gas recirculation rates lower than actual. However, provided the oxygen content of the combined combustion air is always measured at the same location, the relative amount of flue gas recirculated may be ascertained.

define FGR rate as the amount of flue gas recirculated divided by combustion air supplied to the firebox (which is the sum of the fresh air provided and the flue gas recirculated):

1. FGR = amt. recirculated / (amt. fresh + amt. recirculated)

from conservation of species : (Note, O_2 fresh =.209 or 20.9 % by volume):

2. (amt. fresh x $O_{2\,fresh}$) + (amt. recirc. x $O_{2\,recirc}$) = (amt. fresh + amt. recirc.) x ($O_{2\,comb}$)
   (amt. fresh x $O_{2\,fresh}$) + (amt. recirc x $O_{2\,recirc}$) = (amt. fresh) x $O_{2\,comb}$ + (amt. recirc) x $O_{2\,comb}$

combining terms and re-arranging:

(amt. recirc) x ($O_{2\,recirc}$ - $O_{2\,comb}$) = (amt. fresh) x ($O_{2\,comb}$ -$O_{2\,fresh}$)
amt. recirc = (amt. fresh) x [($O_{2\,comb}$ - $O_{2\,fresh}$) / ($O_{2\,recirc}$ - $O_{2\,comb}$)]

substituting in equation 1:

$$FGR = \frac{(\text{amt. fresh}) \times [(O_{2\,comb} - O_{2\,fresh}) / (O_{2\,recirc} - O_{2\,comb})]}{(\text{amt. fresh}) + (\text{amt. fresh}) \times [(O_{2\,comb} - O_{2\,fresh}) / (O_{2\,recirc} - O_{2\,comb})]}$$

canceling the like terms "(amt. fresh)", substituting the identity "($O_{2\,recirc}$ - $O_{2\,comb}$)/($O_{2\,recirc}$-$O_{2\,comb}$)" for "1" in the denominator and canceling like terms "($O_{2\,recirc}$ - $O_{2\,comb}$)" yields:

FGR = ($O_{2\,comb}$ - $O_{2\,fresh}$) / ($O_{2\,recirc}$ - $O_{2\,fresh}$)

ATTACHMENT T

GWF Comments and District Response

The District received comments to the PDOC from GWF Energy LLC. GWF Energy's comments and the District's response is shown below:

GWF Comment:

Pg. 4. Heat Recovery Steam Generators (HRSGs): Insert – ***High-pressure evaporator*** as a bullet point.

District Response:

The District concurs and has added a bullet point.

GWF Comment:

Pg. 5. Existing Diesel-Fired Emergency IC Engine Powering an Electrical Generator: Modify the sentence as follows- Supplementary to the DC battery system, ***an existing*** diesel-fueled emergency generator system will provided long-term power for a safe...

District Response:

The District concurs and has revised the evaluation.

GWF Comment:

Pg. 8. Post-Project Equipment Descriptions: Modify the description – N-4597-5-0:

85 MMBTU/HR NATURAL GAS-FIRED RENTECH MODEL RTD-2-60 BOILER WITH A ***COEN*** C-RMB BURNER AND FLUE GAS RECIRCULATION OR EQUIVALENT

District Response:

The District concurs and has revised the equipment description.

GWF Comment:

Pg 10. N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators: Change the sulfur content value – Reductions in particulate matter are achieved by limiting the quantity of sulfur in the fuel and the ammonia slip. The applicant has proposed the use of natural gas fuel with a maximum sulfur content of ***0.66*** grains/scf and has proposed to limit ammonia slip emissions to 5 ppmvd NH_3 @ 15% O_2.

District Response:

The District concurs and has revised the evaluation.

GWF Comment:

Pg. 13. Assumptions: N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators: Bullets 3, 4, & 5 – Delete the following- Maximum daily emissions for each CTG for NOx and CO are estimated assuming a worst-case scenario consisting of one cold startup (3 hr), one hot startup (1 hr), two shutdowns (1.3 hr) and 18.7 hours of steady state operation at 15 degrees F ambient temperature ~~***with evaporative coolers operating***~~ and duct burners firing.

District Response:

The District concurs and has revised the evaluation.

GWF Comment:

Pg. 18. Emission Factors: Post-Project Turbine Startup and Shutdown Emission Factors: Table – Proposed Worst Case Hourly Emissions During Shutdown, Per Turbine – Correct the SOx and PM10 values

NOx (lb/hr)	106.00
CO (lb/hr)	149.00
VOC (lb/hr)	3.15
SOx (lb/hr)	***1.23***
PM10 (lb/hr)	***3.77***

District Response:

The District concurs and has corrected the table.

GWF Comment:

Pg. 35. N-4597-5-0: Auxiliary Boiler – Proposed 1080 conditions: Delete all bullets and insert Condition 11 from the PDOC for N-4597-5-0.

The exhaust stack shall either be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O_2 or the owner/operator shall implement one of the alternate monitoring schemes (A, B, C, D, E, F, or G) listed in District Rule 4320, Section 5.7.1 (dated 10/16/08). Owner/Operator shall submit, in writing, the chosen method of monitoring (either CEMS or chosen alternate monitoring scheme) at least 30 days prior to initial operation of this boiler. [District Rules 2201, 4305, 4306, and 4320]

District Response:

The District concurs and has revised the evaluation.

GWF Comment:

Pg. 38. Rule 1081 Source Sampling: Bullet #10 Addition of Approved Methods –

- The following test methods shall be used: NOx - EPA Method 7E ***or 20*** or ARB Method 100 ***and EPA Method 19 (Acid Rain Prog)*****;** CO - EPA Method 10 or 10B ***or ARB Method 100***; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 ***and 202*** (front half and back half) or 201***a*** and 202***a***; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 ***or ARB Method 100***. 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) and 40 CFR 60.4400(a)(2), (3), and (b)]

District Response:

The condition has been revised to read as follows:

- The following test methods shall be used: NOx - EPA Method 7E or 20 or ARB Method 100 and EPA Method 19 (Acid Rain Program); CO - EPA Method 10 or 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 and 202 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or ARB Method 100. NOx testing shall also be conducted in accordance with the requirements of 40 CFR 60.4400(a)(2), (3), and (b). 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) and 40 CFR 60.4400(a)(2), (3), and (b)]

GWF Comment:

Pg. 48. Offset Applicability: Insert VOC – As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NOx, ***VOC***, and PM10 emissions.

District Response:

The District concurs and has revised the evaluation.

GWF Comment:

Pg. 49. Quantity of Offsets Required: Third Sentence: Delete 00- The applicant has proposed that any N***00O***$_x$ emissions surplus of SSPE2 be allocated towards meeting their VOC and PM10 offset requirements.

District Response:

The offsets section language has been completely revised to address EPA comments. This comment no longer applies to the evaluation.

GWF Comment:

Pg. 52. Daily Emission Limits: Correct SOx value – Emission Rates from this CTG without the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 8.10 lb/hr and 2.0 ppmvd @ 15% O2; CO – 3.90 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 1.13 lb/hr and 1.5 ppmvd @ 15% O2; PM10 – 4.40 lb/hr; or SOx (as SO2) – ***2.03*** lb/hr...

District Response:

The District concurs and has revised the condition.

GWF Comment:

Pg. 70. Compliance Assurance: 40 CFR 60- Subpart KKKK: Standards for Nitrogen Oxides: Correct SOx value - Emission Rates from this CTG without the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 8.10 lb/hr and 2.0 ppmvd @ 15% O2; CO – 3.90 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 1.13 lb/hr and 1.5 ppmvd @ 15% O2; PM10 – 4.40 lb/hr; or SOx (as SO2) – ***2.03*** lb/hr...

District Response:

The District concurs and has revised the condition.

GWF Comment:

Pg. 74. Compliance Assurance: 40 CFR 60. – Subpart KKKK: CEMS Data and Excess NOx Emissions: add text – (c) Correction of measured NOx concentrations to 15 percent O_2 is not allowed ***except for determination of compliance with Section 60.4350***.

District Response:

Pursuant to discussion with EPA Region 9, this requirement from Subpart KKKK is erroneous. Therefore, the language referring to this requirement has been removed from the evaluation entirely.

GWF Comment:

Pg. 83. Rule 4201 Particulate Matter Concentration: N-4597-1-5 and N-4597-2-5: Combustion Turbine Generators: Correct the following values –
Max PM10 emission rate **=** ***5.8*** lb/hr; PM Conc. (gr/scf) = [(***5.8*** lb/hr)

District Response:

The District concurs and has revised the evaluation.

GWF Comment:

Pg. 90. Section 5.8, Compliance Determination: Add the following text – ~~***{2980}***~~ For emissions source testing, the arithmetic average of three 30-consecutive-minute **(or longer periods as necessary)** test runs shall apply. If two or three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]

District Response:

The District concurs and has revised the condition.

GWF Comment:

Pg. 92 Section 6.2, Test Methods: Add the following text – 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]

- NOx emissions for source test purposes shall be determined EPA Method 7E, ***20***, or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320] ***Correct in Table as well***

- CO emissions for source test purposes shall be determined using EPA Method 10, ***10B*** or ARB Method 100. [District Rules 4305, 4306, and 4320] ***Correct in Table as Well.***

- ***Add VOC Test Method Requirements***

- ***Add PM10 test method Requirements***

- Stack Gas Velocities (in Table) – EPA Method 2 ***or 19***

District Response:

The District concurs with the proposed changes to conditions {109}, NOx, CO, and to the Stack Gas Velocities in the table and has revised the evaluation accordingly. The VOC and PM10 requirements have not been added to this section, as District Rule 4702 does not address test method requirements for these pollutants.

GWF Comment:

Pg. 92-93. Section 6.3, Compliance Testing: Delete the following document references – ~~*{3467}; {3466}; {110}*~~

District Response:

The District has removed the general condition reference numbers from the evaluation.

GWF Comment:

Pg. 96-97. N-4597-6-: Fire Pump Engine: Delete the document references in the section, ex ~~*{3816}*~~

District Response:

The District has removed the general condition reference numbers from the evaluation.

GWF Comment:

Pg. 98. Section 5.1 – NOx Emission Requirements: ***Correct the following values –***

- Emission rates from this CTG without the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 8.10 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.90 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 1.13 lb/hr and 1.5 ppmvd @ 15% O_2; PM_{10} – **4.40** lb/hr; or SO_X (as SO_2) – 2.03 lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

- Emission rates from this CTG with the duct burner firing, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 10.30 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 6.00 lb/hr and 2.0 ppmvd @ 15% O_2; VOC (as methane) – 3.22 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – **5.80** lb/hr; or SO_X (as SO_2) – **2.63** lb/hr. NO_X (as NO_2) emission rates are one hour rolling averages. All other emission rates are three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

District Response:

The District concurs and has revised the conditions.

GWF Comment:

Pg. 99 Section 5.1 – CO Emission Requirements: Correct value of PM10 and SOx similar to Section 5.1 on page 98 (see above comment)

District Response:

The District concurs and has revised the conditions.

GWF Comment:

Pg. 106 Section 6.3 and 6.4 – Compliance Testing: Correct Test Methods –

- The following test methods shall be used: NOx - EPA Method 7E ***or 20*** or ARB Method 100 ***and EPA Method 19 (Acid Rain Prog)***; CO - EPA Method 10 or 10B ***or ARB Method 100***; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 ***and 202*** (front half and back half) or 201***a*** and 202***a***; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 ***or ARB Method 100***. 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) and 40 CFR 60.4400(a)(2), (3), and (b)]

District Response:

The condition has been revised to read as follows:

- The following test methods shall be used: NOx - EPA Method 7E or 20 or ARB Method 100 and EPA Method 19 (Acid Rain Program); CO - EPA Method 10 or 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 and 202 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or ARB Method 100. NOx testing shall also be conducted in accordance with the requirements of 40 CFR 60.4400(a)(2), (3), and (b). 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) and 40 CFR 60.4400(a)(2), (3), and (b)]

GWF Comment:

Pg. 119 Billing Information: Correct miscalculation of annual fees.

District Response:

The District concurs and has revised the annual fees table.

GWF Comment:

The conditions make two references that could be a conflict. There is a reference to Owner or Operator and the second reference is to permittee. It would be prudent to identify one respondent party by title throughout the permit conditions.

District Response:

The term "Permitee" has been replaced by "Owner/operator" throughout the document.

GWF Comment:

Please make the following revision to the PDOC conditions from N-4197-1-5 and N-4197-2-5:

10. Coincident with the steady state operation of the SCR system and the oxidation catalyst at loads greater than 50% and after installation and tuning of emission controls, NOx, CO, and VOC emissions from this unit shall comply with the emission limits specified in conditions ***#28*** and ***#29*** of this permit. [District Rule 2201]

13. During the initial commissioning activities, the owner/operator shall demonstrate compliance with the NOx emission limit specified in condition #12 through the use of properly operated and maintained continuous emission monitor located within the inlet section of the steam generator unit. Upon completion of the initial commission activities and with the installation of the SCR system and oxidation catalyst, the owner/operator shall demonstrate compliance with the NOx and CO emission limits specified in conditions ***#28, #29, #30, and #31*** through the use of properly operated and maintained continuous emission monitors as specified in conditions #52 and #53. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitors source is not in operation). [District Rule 2201]

The start up event is defined as the period beginning with the gas turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in condition ***#28*** or condition ***#29*** depending on the operating conditions of the duct burner during the start up event. A shutdown event is defined as the period beginning with the turbine shutdown sequence and ending with the cessation of firing the gas turbine engine. [District Rules 2201 and 4703]

District Response:

These conditions have been revised to reference the correct conditions from the FDOC.

GWF Comment:

Please combine the following conditions on the PDOC for N-4597-4-2 and remove any redundant conditions:

- Emissions from this IC engine shall not exceed any of the following limits: 4.69 g-NOx/bhp-hr, 0.12 g-CO/bhp-hr, or 0.04 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115 and 40 CFR 60.4205(b)]

- Emissions from this IC engine shall not exceed 0.029 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 and 40 CFR 60.4205(b)]

District Response:

Per District practice, these conditions are kept separate on the permit. Redundant conditions have been removed.

ATTACHMENT U

EPA Comments and District Response

The District received comments on the PDOC from EPA Region 9 prior to the end of the 45 day comment period. The following is a summary of the EPA Region 9 comments and the District's response to each comment.

EPA Comment #1: Offsets Required for PM10 and VOC Emissions

Offsets required for PMI0 and VOC emissions GWF Tracy is required to provide offsets for the net emission increases of VOC and PM10 resulting from the project. To meet this requirement, GWF Tracy proposed (on page 49) to allocate any excess NOx emissions towards meeting the VOC and PM10 offset requirements by "re-bank[ing] the [NOx] ERCs that they originally provided." However, this type of "rebanking" does not comply with the Clean Air Act's requirement under Section 173(a) that the offsets be real emission reductions'. The ERCs that GWF Tracy surrendered to permit the original Tracy Peaker Project in 2003 were consumed by the original permitting action and cannot be re-banked as ERCs. Accordingly, GWF has no valid NOx ERCs to use as interpollutant offsets for VOC and PMI0. Therefore the project does not meet the NSR requirements to provide offsets for increased VOC and PMI0 emissions.

District Response for EPA Comment #1:

EPA and the District have discussed these comments further and agree that since the VOC and PM10 offsets being provided for this project do not meet the requirements for use as federal offsets, the District will, pursuant to Rule 2201, Section 7, treat these offsets as we do all non-federally-approvable offsets that are used under our NSR program. That is, the District will debit the amount of federally required VOC and PM10 offsets for this project in our tracking system to ensure federal offset requirements are met.

EPA Comment #2: Interpollutant Offsetting

Although the project relies on inter-pollutant offset ratios of 1:1 and 2.629:1 for NOx-to-VOC and NOx-to-PM10, respectively, the underlying methodology to determine the appropriate ratios for inter-pollutant offsets has not been approved by EPA as required by District Rule 2201. The burden in seeking approval for inter-pollutant offsets rests with GWF Tracy to demonstrate that the proposed inter-pollutant offsets will ensure a net benefit to air quality levels in the area of the proposed project. It is important to note that modeling is a critical component of an inter-pollutant offset analysis, and subsequent models are evaluated on a case-by-case basis. Any approach for inter-pollutant offsets, therefore, must be carefully considered by the agencies in the context of a thorough and descriptive protocol. EPA must concur with the assumptions and methodology before such ratios may be used in this project. Even though a proposed methodology has been presented in a District attainment plan, it should not be inferred that the methodology has been automatically approved for use in this project. Accordingly, GWF Tracy and SJVAPCD must work with EPA on such protocol to be reviewed in advance of an acceptable methodology. We are available to discuss the schedule for submission of such a protocol and its components. At a minimum, the protocol should include standard information, such as model choice, episode selection, emissions inventory parameters, and performance criteria.

District Response for EPA Comment #2:

EPA and the District have discussed these comments further and agree that since the VOC and PM10 offsets being provided for this project do not meet the requirements for use as federal offsets, the District will, pursuant to Rule 2201, Section 7, treat these offsets as we do all non-federally-approvable offsets that are used under our NSR program. That is, the District will debit the amount of federally required VOC and PM10 offsets for this project in our tracking system to ensure federal offset requirements are met.

EPA Comment #3: BACT Evaluation for Startup and Shutdown Operating Scenarios

We note that the District has included permit conditions for startup and shutdown (SU/SD) operating scenarios (e.g., mass limits, duration of startups and shutdowns, definitions of operating scenarios, etc.) for two combustion turbine generators in the PDOC. However we do not see a proper BACT analysis for operation during these periods. We are aware of several projects in California that are considering technologies and work practices that minimize duration and emissions during such operating scenarios from stationary combustion turbines in their BACT evaluations. Please provide an appropriate BACT analysis for operation during startup and shutdown periods.

Although the District imposes the condition on the project to maintain the units in good operating condition and operate in a manner to minimize emissions, we request additional information be included in the District's evaluation that supports the proposed permit conditions (such as emission limits, durations, and definitions) for SU/SD operations.

EPA requires that BACT apply not only during normal, steady-state operations but also during all transient operating periods such as SU/SD periods. Therefore, as part of the BACT evaluation, we expect applicants to consider operating approaches, operating controls, work practices, and equipment performance and design that would minimize SU/SD emissions. Please refer to the following two decisions from EPA's Environmental Appeals Board (EAB) that provide context in this matter. They are Rockgen Energy Center (PSD Appeal No. 99-1) (http://www.epa.gov/eab/diskl1/rockgen.pdf) and Tallmadge Generating Station (PSD Appeal No. 02-12) (http://www.epa.gov/eab/orders/tallmadge.pdf).

District Response for EPA Comment #3:

The District concurs and has conducted an analysis of BACT for startup and shutdown periods for the turbines. This analysis is included in Attachment K of this document. The following conditions have been added to the turbine permits as a result of the BACT analysis:

- *During all types of operation, including startup and shutdown periods, ammonia injection in to the SCR system shall occur once the minimum temperature at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The minimum catalyst face temperature shall be determined during the final design phase of this project and shall be submitted to the District at least 30 days prior to commencement of construction. [District Rule 2201]*

- *The SCR system shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the catalyst face. [District Rule 2201]*

EPA Comment #4: Federally Enforceable limits on PTE for stationary gas turbines and auxiliary boiler

While the PDOC contains conditions for startup and shutdown (SU/SD) operating scenarios (e.g., mass limits, duration of startups and shutdowns, definitions of operating scenarios, etc.), it should also contain limits on the number of such events when operating under combined-cycle operation, since the evaluation is based on an assumed number of these events (page 26 and Attachment G of the PDOC). Likewise, the calculations were based on a total of 8,639 hours of operation per year rather than the maximum of 8,760 hours in a year.

For these reasons, the proposed permit conditions must include limits on the capacity utilization and/or hours of operation to properly reflect the scenarios used in the emission calculations. Furthermore, the permit must include proper monitoring and recordkeeping conditions for such limits.

District Response for EPA Comment #4:

We disagree. The hypothetical operating scenarios provided by the applicant and contained within the PDOC evaluation were used to establish the maximum annual emission limits for each turbine and the auxiliary boiler. It is these maximum emissions that must be enforced and such limits are included as permit conditions in the PDOC. Additionally, the PDOC requires the applicant to keep emission records on a rolling 12-month basis for each pollutant. For NOx and CO emissions, the NOx and CO CEMs will be used to track rolling 12-month emissions. Rolling 12-month SOx emissions will be calculated using the monthly sulfur content monitoring data and monthly fuel usage. Rolling 12-month VOC and PM10 emissions will be calculated using the rolling 12-month fuel usage and source test data. The following condition has been revised to further clarify the method of showing compliance with the annual emission limits:

- *Annual emissions from the CTG, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 88,881 lb/year; CO – 74,598 lb/year; VOC – 15,145 lb/year; PM_{10} – 32,250 lb/year; or SO_X (as SO_2) – 7,084 lb/year. <u>Compliance with the annual NOx and CO emission limits shall be demonstrated using CEM data and compliance with the annual VOC, PM10 and SOx emission limits shall be demonstrated using the most recent source test results.</u> [District Rule 2201]*

EPA Comment #5: Limiting fuel usage and PTE of HAPs

Because the calculated PTEs of any individual HAP (e.g., formaldehyde) and of the total HAPs are within close to 6% of triggering the threshold for a major HAP source, the final DOC must include federally enforceable limits on the annual fuel usage rates for each emission unit at the source and the PTE for any individual HAP and for total HAPs. As calculated annual PTE's and fuel usage rates are indicated on pages 64-65, the PTE for formaldehyde is 9.4 tons per year and total HAPs of 23.3 tons per year. As such, the final DOC must include recordkeeping conditions that require the operator to calculate, on a monthly basis, the rolling 12-month averages of actual fuel usages for each emission unit and to comply with their associated conditions that limit the PTEs of any individual HAP and of the total HAPs.

Furthermore, should the number of operating hours increase and/or, in turn, calculations of HAP emissions result in a finding that the source is a major source for HAPs, please evaluate the applicability of NESHAPs/MACTs (including, but not limited to, CFR Subparts YYYYand DDDDD of Part 63 of title 40), identify the applicable requirements for this source, and include adequate permit conditions to assure compliance with them. While this is not necessary to address NSR requirements, the issuance of the COC is contingent upon the District adding the necessary conditions to the title V portion of the permit.

District Response for EPA Comment #5:

The District has added a rolling 12-month fuel usage limit for the turbines to ensure that the rolling 12-month HAP emissions from this facility do not equal or exceed the Major HAP source thresholds. Condition #68 of the PDOC for each turbine already requires the facility to keep rolling twelve month fuel consumption records for the turbines. The boiler HAP emissions are based on the maximum hourly fuel rate of the boiler and the 4,000 hr/year operating limit from Condition #12 from the draft Boiler permit in the previously provided PDOC. Maximum HAP emissions for the emergency IC engines are now calculated on the EPA guidance of 500 hours/year as a worst-case assumption for emergency engines. The following condition has been added to limit HAP emissions from the turbines, such that the Major Hap Source Threshold is not surpassed:

- *The combined natural gas fuel usage for permit units N-4597-1 and N-4597-2 shall not exceed 20,454 MMscf/year. [District Rule 2550]*

EPA Comment #6: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ, and their Applicable Requirements

Please indicate whether NSPS Subpart IIII and MACT Subpart ZZZZ apply to the project, identify the applicable requirements for this project, and include adequate permit conditions to assure compliance with them. While this is not necessary to address NSR requirements, the issuance of the COC is contingent upon the District adding the necessary conditions to the title V portion of the permit.

District Response for EPA Comment #6:

40 CFR Subpart IIII and 40 CFR Subpart ZZZZ are applicable and compliance discussions have been added to the evaluation for each of the proposed emergency compression ignition internal combustion engines. Additionally, the appropriate permit conditions have been added to the evaluation.

EPA Comment #7: PDOC is not a Written Certificate of Conformity (COC)

Because the conditions under section 6.1 of District Rule 2201 have not been met, the PDOC does not serve as a written COC despite the proposed permit condition on page 61 stating otherwise. Section 6.0 (Certification of Conformity) of District Rule 2201 states that the COC may be issued only after all of the conditions under section 6.1.1 through 6.1.6 are met. Generally, some of these conditions include conformity with the Enhanced Administrative Requirements of District Rule 2201 and mandatory permit content for title V permits in District Rule 2520. Because the Authority to Construct has not been issued and will not be issued until our comments in this letter and comments from other agencies are resolved, the PDOC cannot serve as a written COC. Please make appropriate changes to reflect this in the FDOC.

District Response for EPA Comment #7:

We agree the PDOC is not the equivalent of an ATC – it is the equivalent of a preliminary determination to issue an ATC, and so we agree that the PDOC cannot serve as the COC. However, the FDOC does and will serve as the COC. All comments have been resolved for this project and the appropriate conditions have been included on the FDOC.

Comment #8: SCR operation and startup and shutdown events

It is unclear if the PDOC assumes operation of the SCR during startup and shutdown events. If it is the District's intention, as part of BACT that the SCR should be in operation as soon as technically feasible, please add conditions to both require its use and monitoring provisions to ensure the SCR unit is in operation during startup and shutdown events. Examples of such conditions could include: 1) require the installation and maintenance of a working temperature gauge at the inlet or the catalyst bed of the SCR system and 2) require the monitoring and recording of the temperature over which the control system ought to be operating.

District Response for EPA Comment #8:

The requirements for operation of the SCR system during startup and shutdown was determined as part of the BACT analysis for startups and shutdowns in accordance with EPA comment #3 above. Please refer to the response for EPA Comment #3.

EPA Comment #9: Monitoring, recordkeeping, and recording for visible emissions

Visible emissions from the electrical generator lube oil vents and from the exhaust of the diesel-fired internal combustion engine are subject to SIP-approved District Rule 4101. While subsection 6.1 of the rule identifies US EPA Method 9 for visual determination of the opacity, provisions for monitoring, recordkeeping, and recording should be considered and are required under title V (per section 9.0 of District Rule 2520). Examples of considerations include: 1) requirement to conduct periodic monitoring/inspection and to record the opacity readings (along with their times and dates); 2) requirement to conduct the monitoring while the equipment is operating and during daylight hours; 3) requirement to take corrective action that eliminates the visible emissions during X hours and report the visible emissions as a potential deviation in accordance with the permit's reporting requirements; 4) requirement to verify and certify within X hours that the equipment causing the visible emissions has been fixed; and 5) requirement that the operator maintain and make available upon request records of emission point(s), of descriptions of corrective actions taken, of date and time emissions were abated, and of records of emission readings. Please include these requirements as appropriate into the FDOC. Issuance of the COC is contingent upon the District adding the necessary conditions to the title V portion of the permit.

District Response for EPA Comment #9:

Natural Gas Fired Turbine:

The District has not previously included any type of visible emissions testing requirements on its permits for natural gas fired turbines. In addition, the District's Title V monitoring, reporting and recordkeeping (MRR) policy states that additional opacity MRR conditions are only required for diesel fired turbines which is consistent with CAPCOA's "Summary Of Periodic Monitoring Recommendations For Generally Applicable Requirements in SIP" document, dated June 24, 1999, as it does not recommend any additional opacity MRR conditions for gas-fired turbines.

Diesel Fired Emergency Internal Combustion Engine:

The District has not previously included any type of visible emissions testing requirements on its permits for diesel fired internal combustion engines that are primarily used for emergency purposes. In addition, the District's Title V monitoring, reporting and recordkeeping (MRR) policy states that no additional opacity MRR conditions are required for diesel fired standby and emergency IC engines which is consistent with CAPCOA's Periodic Monitoring Recommendations, as it does not recommend anyadditional monitoring for diesel fired emergency IC engines which are fired on CARB certified diesel fuel, since is has a very low sulfur content and has a low aromatic content (reference CAPCOA's Summary Of Periodic Monitoring Recommendations For Generally Applicable Requirements in SIP, June 24, 1999).

In addition, each District compliance staff member is certified to perform visible emissions testing in accordance with EPA Method 9. During the source's annual inspection, the District compliance staff member will observe the equipment to ensure that there are no visible emission violations.

Therefore, the District does not feel it is necessary to add conditions to the PDOC requiring GWF Tracy to perform periodic visible emission tests in accordance with EPA Method 9.

EPA Comment #10: CEM during startup, shutdown, and malfunction events

Please propose a permit condition that requires the operator to keep the Continuous Emission Monitoring running during all startup, shutdown, and malfunction events provided that the CEM data is certifiable to determine compliance with startup and shutdown emission limits. Even though it may be implicit that CEM equipment is required to operate during all startup, shutdown, and malfunction events, it should be clarified to the operator through an explicit permit condition.

District Response for EPA Comment #10:

FDOC Condition #56 for each of the turbines has been revised to clarify that the CEMs must be running during all types of operation. The revised condition is shown below:

- *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 monitor emissions during all types of operation, including during startup and shutdown periods, 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 60.4335(b)(1)]*

EPA Comment #11: PM2.5 Emissions from Project

Please provide actual calculations of PM2.5 emissions that would be expected from the project and perform an evaluation whether the amounts of emissions would trigger new source review. The PDOC (on page 119) has only an abbreviated discussion of PM2.5 emissions on the applicability of 40 CFR 51 Appendix S.

District Response for EPA Comment #11:

Such calculations are unnecessary since the District conservatively assumed that all the PM10 emitted would be emitted as PM2.5. Using this very conservative assumption, the PM2.5 emissions from this project do not trigger 40 CFR 51 Appendix S NSR requirements.

Comment #12: Fuel Sulfur Content limit (rolling 12-month average)

Please provide an alternative calculation methodology to determine the rolling 12-month average fuel sulfur content contained in proposed Condition 50 in Attachment A-20. The currently proposed methodology can potentially bias the rolling average by allowing more than one data point in a month. Because of the potential for under-estimation of actual emissions, an alternative methodology should be proposed.

District Response for EPA Comment #12:

The methodology has been revised to address the EPA comment. The methodology outlined in FDOC condition #53, added to each permit, adequately addresses this comment.

- *Compliance with the rolling 12-month average fuel sulfur content limit shall be demonstrated monthly. The 12-month rolling average fuel sulfur content shall be calculated as follows: 12-month rolling average fuel sulfur content = Sum of the monthly average fuel sulfur contents for the previous 12 months ÷ total number of months the unit has operated in during the previous 12 months. The monthly average fuel sulfur content is the average fuel sulfur content of all tests conducted in a given month. If the unit is not operated during an entire calendar month, fuel sulfur content testing shall not be required for that specific month. Owner/operator shall keep a monthly record of the rolling 12-month average fuel sulfur content. [District Rules 1081 and 2201]*

EPA Comment 13: FGR Control Technology in Auxiliary Boiler

Please propose a permit condition that requires the operator to properly operate and maintain the flue gas recirculation system since it is an important part of NOx control for the boiler.

District Response for EPA Comment #13:

The Flue Gas Recirculation (FGR) system is identified in the equipment description for the boiler, and must be operated to maintain compliance with the emission limits contained in the permit. The District has added the following condition (FDOC Condition #11, Permit 5-0) that requires the operator to properly operate and maintain the flue gas recirculation system.

- *The flue gas recirculation (FGR) system shall be operated properly and shall be maintained per the manufacturer's recommendations. [District Rule 2201]*

EPA Comment #14: CTG Sox emissions limit during shutdown

Please correct the proposed permit condition containing the SOx emission limit for the CTG during shutdown (Condition 31 in Attachment A-5) to reflect the amount of 0.85 lb/event as indicated in the table titled "Shutdown Emission Factors, Per Turbine, Scenario 1," on page 18.

District Response for EPA Comment #14:

We disagree. The highest shutdown emissions for SOx occur in Scenario 2 (1.1 lb/event, rounded up from 1.05 lb/event per the Districts significant digit policy). Additionally, the 1.1 lb/event value was used in the daily and annual SOx emission calculations in the PDOC. Therefore, the District believes the shutdown emission limit for SOx was appropriately set equal to the maximum value expected from the turbine.

EPA Comment #15: 40 CFR 60 Subpart Dc

a. Please edit proposed Condition 11 on Attachment A-28 to require the fuel flow meter to be calibrated and maintained properly.

b. Please propose a permit condition that requires the operator to conduct a performance test since section 60.8 in 40 CFR 60 requires one; as section 60.8 of part 60 applies, the operator must conduct a performance test according to the requirements in section 60.44c. Also, please consider re-evaluating the applicability of section 60.44c as it pertains to the auxiliary boiler.

c. Please clarify the applicability of subsections 60.47c(e) and 60.47c(f) as they pertain to the auxiliary boiler. Under those requirements, the operator may have to evaluate whether COMS would be required.

District Response for EPA Comment #15:

a. The District has edited proposed condition #11 of the PDOC to require the fuel flow meter to be calibrated and maintained properly.

b. 60.44c(a)specifies the compliance and performance test methods and procedures for sulfur dioxide. The applicable sulfur dioxide standards are listed in 60.42c. These standards only apply to units that fire on oil, coal or some combination of these fuels. Since the proposed boiler will fire only on natural gas, the provisions of 60.44c are not applicable. No change will be made to the PDOC.

c. 60.47c(e) states that owners and operators of an affected facility subject to an opacity standard in 60.43c(c) are not required to install and operate a COM's if they meet specific criteria that is detailed further in 60.47c(e). The opacity limit of 60.43c(c) applies only to affected facilities that can combust coal, wood, or oil. The proposed boiler is only fired on natural gas; therefore, the opacity requirement of 60.43c(c) is not applicable. Since the opacity requirement of 60.43c(c) is not applicable, 60.47c(e) is not applicable.

60.47c(f) states that the owner and operators of an affected facility that is subject to an opacity standard in 60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most requirements of 60.48Da of this subpart is not required to operate a COMS. The proposed boiler is not subject to the opacity standard in 60.43c(c). Therefore, section 60.47c(f) is not applicable.

EPA Comment #16: Subpart KKKK

a. Subsection 60.4345(a). Please propose a condition that requires the RATA of the CEMS to be performed on a lb/MMBtu basis.
b. Subsection 60.4345(e) (CEM Quality Assurance Plan). Please propose conditions in the final Determination of Compliance (FDOC) that require the owner or operator to 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 subsection 60.4345.
c. Subsection 60.4350(b). Please propose conditions that 1) impose a maximum of 19% 02 diluent cap value and 2) calculate and record hourly NOx rate in ppm using Method 9 of 40 CFR 60, Appendix A. As currently proposed, the requirements contained in paragraphs 5.2 through 5.3.3 of Appendix P in 40 CFR 51 do not apply here as the project does not involve any nitric acid plants nor sulfuric acid plants.
d. Subsection 60.4350(h) (data calculation protocols). Please propose conditions in the FDOC that capture the applicable requirements contained in paragraph (h) of subsection 60.4350 after its evaluation has been performed.
e. Subsection 60.4380(b)(1). Please consider proposing conditions that reflect the applicable calculation methodologies in this subsection.
f. Subsection 60.4385(a) and (c). Please consider proposing conditions that indicate the sets of circumstances that would constitute excess emissions and downtime.
g. Subsection 60.4400(a). Please consider proposing conditions that reflect the applicable elements contained in paragraphs (a)(2), (a)(3), and (b).

District Response for EPA Comment #16:

a. It is the Districts understanding that the RATA test is only required to be performed on a lb/MMBtu basis if the RATA test is conducted pursuant to Part 75. The following condition, from the PDOC, has been modified to include this requirement:

- *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, or 40 CFR Part 75 Appendix B, at least once every four calendar quarters. The owner/operator 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. If the RATA test is conducted as specified in 40 CFR Part 75 Appendix B, the RATA shall be conducted on a lb/MMBtu basis. [District Rule 1080 and 40 CFR 60.4345]*

b. The following condition has been added to address the quality assurance monitoring plan requirement:

- *The owner/operator shall develop and keep on site a quality assurance plan for all of the continuous monitoring equipment described in 40 CFR 60.4345 (a), (c), and (d). [40 CFR 60.4345(e)]*

c. *The district concurs that the requirements contained in paragraphs 5.2 and 5.3.3 Appendix P in 40 CFR 51 are only applicable to nitric acid and sulfuric acid plants. The District has included a conditions requiring the applicant to meet the requirements of* Subsection 60.4350(b).

d. *Since the proposed turbine will operate as a combined cycle, 60.4350(h) specifies that excess emissions be determined on a rolling 30 operating day basis. The hourly average emission rates will be calculated based on emission readings in ppm pursuant to 60.4350(f).*

e. *The following condition from the PDOC has been revised to further clarify the Subsection 60.4380(b)(1) requirement*

- *Excess NOx emissions shall be defined as any 30 day operating period in which the 30 day rolling average NOx concentration exceeds an applicable emissions limit. A 30 day rolling average NOx emission rate is the arithmetic average of all hourly NOx emission data in ppm measured by the continuous 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 NOx emission rates for the preceding 30 unit operating days if a valid NOx emission rate is obtained for at least 75 percent of all operating hours. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx or O2 (or both). [40 CFR 60.4350(h) and 40 CFR 60.4380(b)(1)]*

f. *The following condition has been added to address Subsection 60.4385(a) and (c) requirements:*

- *Excess SOx emissions is each unit operating hour including in the period beginning on the date and hour of any sample for which the fuel sulfur content exceeds the applicable limits listed in this permit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. Monitoring downtime for SOx begins when a sample is not taken by its due date. A period of monitor downtime for SOx also begins on the date and hour of a required sample, if invalid results are obtained. A period of SOx monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)]*

g. Condition #48 of the PDOC for each turbine has been revised, as follows, to address this comment:

- *The following test methods shall be used: NOx - EPA Method 7E or 20 or ARB Method 100; CO - EPA Method 10 or 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 and 202 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or ARB Method 100. NOx testing shall also be conducted in accordance with the requirements of 40 CFR 60.4400(a)(2), (3), and (b). 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) and 40 CFR 60.4400(a)(2), (3), and (b)]*

EPA Comment #17: District Rule 4304

Please propose permit conditions that reflect the applicable requirements of District Rule 4304 as they pertain to equipment tuning procedures for boilers and steam generators.

District Response for EPA Comment #17:

At this time, the applicant has not chosen an applicable alternate monitoring scheme. Therefore, the current PDOC conditions allow GWF to choose their desired monitoring scheme, or install a CEMS at a later date. The applicant is required to submit, in writing, the chosen method of monitoring at least 30 days prior to initial operation of the boiler. At that time, the provisions of the chosen scheme will be added to the permit, and the Rule 4304 requirement would be added, if applicable. If the applicant installs a CEMs or if the applicant chooses Alternative Monitoring Scheme A, tuning of the boiler is not required by District Rules 4305, 4306, 4320, or 4351. The District's alternate monitoring policy, which contains the conditions for each alternate monitoring scheme, was included as attachment S of the PDOC. The conditions will be revised to clarify the method of calculation used to derive rolling 12-months emission records.

EPA Comment #18: District Rule 4703

Subsection 6.2.6. Please propose a permit condition that includes the applicable elements in the operating log.

District Response for EPA Comment #18:

The following condition has been added to address the above comment.

- *The owner/operator shall maintain a system operating log, updated on a daily basis, which includes the following information: The actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and type and quantity of fuel used.*

ATTACHMENT V

CEC Comments and District Response

The following are comments received from the California Energy Commission (CEC), along with District responses to those comments:

CEC Comment:

The PDOC shows that by proposing to reduce potential emissions of nitrogen oxides (NOx), no offsets would be required for the project-related NOx emissions (PDOC p. 48). However, the project proposes to increase the potential emissions of volatile organic compounds (VOC) and particulate matter (PM10), and SJVAPCD Rule 2201 requires offsets for these pollutants. The PDOC proposes to allow "surplus" NOx offsets to satisfy Rule 2201 offset requirements for VOC and PM10 (p. 49). This raises questions as to whether the NOx offsets [or emission reduction credits (ERCs)] that were surrendered for the original project were consumed by the original permitting action, and if they exist today, how should the NOx ERCs be valued? The SJVAPCD has indicated that the ERCs surrendered to permit the original Tracy Peaker Project (TPP) sources in 2003 are now invalid.

Please clarify whether the ERCs surrendered for the Tracy Peaker Project (TPP) in 2003 were made invalid by their surrender.

District Response:

The offset section of this evaluation has been revised to more accurately explain the interpollutant netting action that was used to satisfy the District's offset requirements. Increases in VOC and PM10 emissions were counterbalanced by the decrease in NOx emissions from the project. This interpollutant netting approach does not utilize the "surplus NOx offsets" from the Emission Reduction Credits supplied for the original Tracy Peaker Project (TPP).

The District has come to an agreement with EPA regarding the Federal offset requirements for this project. To address federal offset requirements for this project and ensure that the project is approvable, the District will debit the District's annual offset equivalency tracking system by the appropriate quantities, as appropriate.

Finally, the ERC's surrendered for the Tracy Peaker Project were made invalid by their surrender; however, the validity of the ERC's surrendered for the Tracy Peaker Project does not affect the interpollutant netting action utilized in this project, nor does the status affect the annual offset equivalency tracking demonstration.

CEC Comment:

Please identify which of the ERCs (by certificate numbers) that were originally provided for TPP are currently considered in the PDOC to be "surplus."

District Response:

A determination of the current "surplus" status of the ERC's that were originally provided for the Tracy Peaker Project was not conducted as part of the PDOC evaluation since the surplus values of these ERC's was not required for the interpollutant netting action.

CEC Comment:

Please identify which NOx ERCs (by certificate numbers) would be used to satisfy the project's compliance with Rule 2201 offset requirements for VOC and PM10.

District Response:

NOx ERC's were not used to satisfy compliance with the Rule 2201 offset requirements for VOC and PM10. Rather, the interpollutant netting action described in the revised offsets section was used to satisfy the requirements for VOC and PM10 emissions. To satisfy federal offset requirements, the District has also agreed with EPA to debit the District's offset equivalency tracking system by the appropriate quantities.

CEC Comment:

Please state whether the project's compliance with Rule 2201 offset requirements for VOC and PM10 relies upon NOx ERCs that need to be adjusted to become consistent with applicable air district, state, and/or federal rules and/or planning requirements (per Rule 2301, Section 6.7), including Reasonable Further Progress or requirements for Reasonably Available Control Technology (RACT).

District Response:

The interpollutant netting action does not rely on the surplus value of previously surrendered NOx ERC's.

CEC Comment:

If the values of the NOx ERCs need adjustment, are there sufficient offsets post adjustment to satisfy the VOC and PM10 requirements?

District Response:

As stated above, the interpollutant netting action utilized in this project does not rely on previously surrendered NOx ERC's.

CEC Comment:

Please state whether the project's compliance with Rule 2201 offset requirements for VOC and PM10 relies upon NOx ERCs that are/were subject to the annual equivalency demonstration in Rule 2201 Section 7, and if so, how the equivalency demonstration affects or has affected those NOx ERCs.

District Response:

To satisfy Federal offset requirements, the District has agreed with EPA to debit the Districts annual offset equivalency tracking system by the appropriate amounts for this project. Please note, the annual equivalency demonstration does not affect individual ERC's. Rather, the annual equivalency demonstration evaluates the total cumulative impact of the District's offset requirements and associated requirements for all projects in a tracking year and compares this to the total cumulative impact that would have occurred if Federal offset requirements and associated Federal requirements were utilized.

CEC Comment:

The PDOC (p. 49) states that by reducing the NOx potential-to-emit: "GWF Tracy had the option to re-bank the ERCs that they originally provided," but the PDOC does not explain how "re-banking" could occur under SJVAPCD Rule 2301, Section 4.3. The term "re-bank" does not appear in Rules 2201 or 2301. If Rule 2301, Section 4.3 is being used to bank offsets ". . . pursuant to Section 4.2 . . .," then it is not clear how this project would satisfy Section 4.2, which requires emission reductions to be "real" before they are eligible for banking. The PDOC (pp. 31-32) shows that the TPP pre-project actual emissions of NOx are around 4,000 lb/yr. Thus, the existing TPP has almost no notable actual emissions that may be eligible for banking as real emission reductions.

District Response:

Correct, any ERC's that could be banked pursuant to Section 4.3 of District Rule 2301 would be subject to the requirements of Section 4.2 which include the requirements to be real and surplus.

CEC Comment:

Please clarify whether any new ERCs are being created by the proposed project and describe whether any real emission reductions are occurring.

District Response:

New ERC's are not being created by the proposed project.

CEC Comment:

The discussion of Best Available Control Technologies (BACT, pp. 40-46) 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. Energy Commission staff recommends that the District 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. Energy Commission staff recognizes that the existing Frame 7EA combustion turbines may not be capable of retrofitting to a level of control equivalent to a newer or larger turbine (as in GWF Response to Data Request 6, Dated 11/19/2008, submitted to CEC/Docket Unit on 11/19/2008), but we suggest that SJVAPCD provide information demonstrating that the BACT analysis has considered startup periods. Options for consideration by the SJVAPCD could include control system modifications allowing injection of ammonia earlier or alternative designs for the heat recovery steam generator (HRSG) that reduce the time needed to heat the HRSG without causing thermal stress.

District Response:

A BACT Analysis for startup and shutdown emissions has been added to Attachment K. The District considered Rapid Response Technology from both GE and Siemens, OPFlex, and control system modifications allowing injection of ammonia at the lowest feasible temperature.

CEC Comment:

Energy Commission staff appreciates the explanation of the interpollutant offset ratio provided in the PDOC Attachment O. The report on Interpollutant Ratio Development does not describe whether the ERCs surrendered in 2003 for the original TPP are included in the emissions inventories of the various modeling analyses.

Please describe whether the inventories of nitrate emissions in the receptor modeling or the regional modeling include the ERCs associated with this proposed project.

District Response:

The modeling is based on inventories of actual emissions from industrial sources and the relevant chemical reactions that occur in the atmosphere. Therefore, the ERC's associated with the previous Tracy Peaker Plant project would be reflected in the modeling data as actual emissions from the Tracy Peaker Plant that have occurred since the 2003 original TPP project that are included in the emissions inventory.

CEC Comment:

The modeling for the interpollutant ratio is part of the 2008 PM2.5 Plan that was adopted by the California Air Resources Board on May 22, 2008, and the plan was subsequently submitted to U.S. EPA. However, as of April 2009, there has been no U.S. EPA action on the PM2.5 plan.

Please describe whether the development of the interpollutant ratio has been reviewed and/or approved by U.S. EPA.

District Response:

The District and EPA have come to an agreement that for this project, the appropriate quantities of emissions will be debited in the Districts annual offset equivalency tracking system to address Federal offset requirements. This action has satisfied EPA's concern regarding the use of the interpollutant ratios proposed in the PDOC.

CEC Comment:

The information regarding commissioning (PDOC pp. 15 and 23 and Attachment D) appears to be out of date. PDOC Condition 12 for the stationary gas turbines would allow up to 160.5 pounds per hour (lb/hr) NOx during commissioning. However, in Data Response Set 1 (GWF Response to Data Request 4, Dated 11/19/2008, submitted to CEC/Docket Unit on 11/19/2008), GWF informed the Energy Commission that the maximum emission rate during commissioning would be 146.7 lb/hr NOx.

Please ensure that the commissioning emission limits in Condition 12, and elsewhere, reflect the latest information from GWF.

District Response:

The District Concurs and has revised the commissioning emission rates and limits to be consistent with the data submitted to the CEC on 11/19/2008.

CEC Comment:

Section II regarding Applicable Rules does not describe the applicability of federal New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60 - Subpart IIII).

Please provide a brief description of the applicability of these rules to the emergency standby generator and fire water pump engines.

District Response:

A description of the applicability of Subpart IIII Requirements has been added to the FDOC.

CEC Comment:

The Process Description (PDOC p. 3) appears to be inconsistent with AFC Section 5.1.4.1.4 and Table 5.1-10, which includes a wet surface air cooler (WSAC) that would emit more than 2 lb/day PM10, over the BACT trigger level shown on PDOC p. 41.

Please indicate whether the wet surface air cooler has been considered and identify any applicable requirements or permit conditions.

District Response:

As stated in the Rule 2020 section of the PDOC, the 3,840 gal/min wet surface air cooler (WSAC) is exempt from permit requirements per District Rule 2020 Section 6.2. District Rule 2201's applicability section states Rule 2201 is applicable to Stationary Sources subject to District permitting requirements. Since the WSAC is exempt from District permitting requirements, District Rule 2201 is not applicable and BACT requirements are not applicable.

CEC Comment:

The PDOC (p. 31) shows the project would be a "Federal Major Modification" for NOx, but the meaning of the term "federal" in this context is unclear. The PDOC addresses the applicability of the SJVAPCD NSR program, not the federal Prevention of Significant Deterioration (PSD) program where the term "Federal Major Modification" would seem to apply.

Please explain what are the implications and applicable requirements triggered by the project being a "Federal Major Modification" for NOx.

District Response:

Major Modification is defined in District Rule 2201 as a Major Modification as defined in 40 CFR Part 51.165 (as in effect on December 19, 2002) and part D of Title I of the Clean Air Act. The term "Federal Major Modification" that is utilized in District Rule 2201 refers to Major Modification as defined in the current version of 40 CFR Part 51.165, which includes the provisions and changes that were made by EPA when they implemented Federal NSR Reform.

District Rule 2201 Section 4.15 requires the following for projects that trigger Federal Major Modifications:

1. *An alternative siting analysis.*
2. *The applicant to demonstrate that all other facilities and sources operated by the applicant within the State of California are in compliance with the appropriate air quality regulations, or are scheduled to come into compliance with the appropriate air quality regulations.*

These requirements have been satisfied by GWF Tracy.

The federal major source definition under PSD regulations can be found at 40 CFR 52.21(b)(1)(i). For the GWF Tracy facility, the major source threshold under PSD regulations is 100 ton/yr or 200,000 lb/yr for each criteria pollutant. As is evident from post-project stationary source potential to emit (SSPE2) shown on Page 28, all criteria pollutant emissions are below the 200,000 lb/yr PSD major source threshold and the GWF Tracy facility will not be a major stationary source and will not be subject to federal PSD regulations.

CEC Comment:

Please provide a brief discussion and analysis of the applicability of the federal PSD program.

District Response:

Please see the response to the previous comment.

CEC Comment:

The PDOC (p. 98) mentions installation of four stationary gas turbines in the discussion of Rule 4703 compliance.

Please confirm that the discussion of Rule 4703 is accurate, given the project is for two larger combustion turbines, not four.

District Response:

The Rule 4703 discussion has been corrected to reflect that the project is for two combustion turbines, not four.