San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

DOCKET
01-EP-7C
DATE 9/16/2009
RECD. 10/7/2009

SEP 16 2009

Matt Trask
Compliance Amendment Project Manager
California Energy Commission
1516 Ninth Street, MS 2000
Sacramento, CA 95814

Re: Notice of Final Determination of Compliance (FDOC)
Facility: GWF Energy, LLC – Hanford (01-EP-07C)
Project Number: C-1083169

Dear Mr. Trask:

Enclosed is the District's Final Determination of Compliance (FDOC) for the modification of two 47.5 MW simple-cycle peak-demand power generating gas turbine systems to convert the power plant in to a simple-cycle or combined-cycle power plant with the installation of two new heat recovery steam generators on each turbine's exhaust and one new 25 MW steam turbine (shared between both turbines) and the installation of one 460 bhp diesel fired emergency internal combustion engine powering a firewater pump, located at 10550 Idaho Avenue in Hanford, CA. This letter serves as our notification of final action and enclosed is your copy of the FDOC.

Notice of the District's revised preliminary decision for this project was published on July 27, 2009. Only one comment was received on the District revised preliminary decision. The change resulting from this comment was the addition of missing footnote #3 to the emission standards table in the 40 CFR 60, Subpart IIII discussion of the attached FDOC evaluation (page 71).

The changes made to the Revised Preliminary Determination of Compliance (RPDOC) 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 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the RPDOC 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. Dustin Brown of Permit Services at (559) 230-5932.

Sincerely,

David Warner
Director of Permit Services

DW:ddb

Enclosures

cc: Will Walters, Aspen Environmental Group

Fresno Bee

NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District has issued a Final Determination of Compliance (FDOC) to GWF Energy LLC - Hanford for the modification of two 47.5 MW simple-cycle peak-demand power generating gas turbine systems to convert the power plant in to a simple-cycle or combined-cycle power plant with the installation of two new heat recovery steam generators on each turbine's exhaust and one new 25 MW steam turbine (shared between both turbines) and the installation of one 460 bhp diesel fired emergency internal combustion engine powering a firewater pump, located at 10550 Idaho Avenue in Hanford, CA.

All comments received following the District's preliminary decision on this project were considered. Changes were made to the determination of compliance evaluation 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 C-1083169 is available for public inspection at the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

FINAL DETERMINATION OF COMPLIANCE EVALUATION

GWF Energy LLC - Hanford
California Energy Commission
Application for Certification Docket #: 01-EP-07C

Facility Name:	GWF Energy, LLC - Hanford
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Lead Engineer:	Joven Refuerzo, Supervising Air Quality Engineer
Date:	September 14, 2009
Project #:	C-1083169
Application #'s:	C-4140-1-5, C-4140-2-5 and C-4140-3-0
Date Submitted:	August 4, 2008

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I. PROPOSAL:

GWF Energy LLC – Hanford, herein referred to as GWF Hanford, currently operates a nominally rated 95 megawatt (MW) simple cycle peak demand electrical power generation facility at this location. GWF Hanford is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the modification of their existing power generation facility by converting the facility into a full time combined cycle power generating facility with a nominal increase of 25 MW's in additional power generating capacity. After this modification, this facility will also retain the ability to operate the power plant in simple cycle mode. The modifications for this project include, but are not limited to, the following:

- Demolition and removal of the two existing oxidation catalyst and selective catalytic reduction (SCR) systems serving each combustion turbine generator (CTG), including the existing catalyst housing and 85-foot stacks.
- Addition of two (2) new once through heat recovery steam generators (OTSG's), each receiving the exhaust from one of the existing General Electric LM6000 CTG's. The OTSG's will be vertical flow boilers with rectangular stacks that will be 91 feet, 6 inches tall by 13 feet wide by 8.9 feet long.
- Addition of a new oxidation catalyst system within each OTSG to control carbon monoxide (CO) emissions to an outlet concentration of less than 3 parts per million volume dry (ppmvd) at 15 percent oxygen (O_2) and volatile organic compounds (VOC) emissions to an outlet concentration of less than 2 ppmvd at 15 percent O_2 during simple-cycle and combined-cycle operation.
- Addition of a new SCR system within each OTSG, reusing the existing aqueous ammonia storage system, to control oxides of nitrogen (NO_x) emissions to an outlet concentration of less than 2 ppmvd at 15 percent O_2 during combined-cycle operation and 3.6 ppmvd at 15 percent O_2 during simple-cycle operation.
- Addition of a new 25 MW (net) condensing steam turbine generator (STG) with associated lube oil cooler.
- Addition of a new 74-foot tall by 240-foot long by 45-foot wide air cooled condenser (ACC) for system heat rejection.
- Addition of a new nominal 460 horsepower, diesel-fired engine powering an emergency firewater pump (C-4140-3-0)

As shown in Section VIII, District Rule 2201 of this document below, GWF Hanford is located next to, is under common ownership, and falls within the same industrial grouping by virtue of falling within the same two-digit standard industrial classification code as the existing Hanford LP facility (facility ID C-603). Therefore, for the purposes of this project, these two sources will be considered part of the same stationary source.

GWF Hanford is subject to approval by the 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 Hanford received their Title V Permit on January 31, 2004. This modification can be classified as a Title V significant modification pursuant to Rule 2520, Sections 3.2, 3.20 and 3.29, 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 will be satisfied prior to the issuance of the Final Determination of Compliance (FDOC). GWF Hanford must apply to administratively amend their Title V Operating Permit to include the requirements of the FDOC issued with this project.

II. APPLICABLE RULES:

Rule 1080	Stack Monitoring (12/17/92)
Rule 1081	Source Sampling (12/16/93)
Rule 1100	Equipment Breakdown (12/17/92)
Rule 2010	Permits Required (12/17/92)
Rule 2201	New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 2540	Acid Rain Program (11/13/97)
Rule 2550	Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001	New Source Performance Standards (4/14/99) Subpart GG - Standards of Performance for Stationary Gas Turbines Subpart KKKK - Standards of Performance for Stationary Combustion Turbines Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/18/00) Subpart ZZZZ - Standards of Performance for Stationary Reciprocating Internal Combustion Engines
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4202	Particulate Matter Emission Rate (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4702	Internal Combustion Engines – Phase 2 (1/18/07)
Rule 4703	Stationary Gas Turbines (9/20/07)
Rule 4801	Sulfur Compounds (12/17/92)
Rule 8011	General Requirements (8/19/04)
Rule 8021	Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)

Rule 8031 Bulk Materials (8/19/04)
Rule 8041 Carryout and Trackout (8/19/04)
Rule 8051 Open Areas (8/19/04)
Rule 8061 Paved and Unpaved Roads (8/19/04)
Rule 8071 Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
Rule 8081 Agricultural Sources (9/16/04)

Public Resources Code 21000-21177 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
Federal NSR Requirements for PM2.5 – 40 CFR 51 Appendix S

III. PROJECT LOCATION:

GWF Hanford is located at 10596 Idaho Avenue in Hanford, CA. The proposed plant will occupy an approximate 4.7-acre, fenced site within the existing GWF-owned 10-acre parcel (see site location and layout maps in Attachment C).

The site is located south of the City of Hanford in Kings County, CA. The District has verified that the proposed location is not within 1,000 feet of a K-12 school.

IV. PROCESS DESCRIPTION:

GWF Hanford is requesting to convert their existing 95 MW peak demand, simple cycle power plant to a simple cycle or combined cycle power plant with a nominal increase of 25 MW of additional electrical power generating capacity.

The modified GWF Hanford plant will consist of the two existing GE LM6000 PC Sprint CTG's which are equipped with water injection for the control of NO_X emissions, power augmentation, and evaporative cooling of the CTG air inlet. Each existing CTG drives an electrical generator that produces 47.5 MW of electricity. The exhaust of each CTG will be routed through two new unfired once through heat recovery steam generators (OTSG's). The OTSG's will each be equipped with an SCR system for NO_X emission control and an oxidation catalyst for CO and VOC emission control. Steam generated by the two OTSG's will flow through a new steam turbine. The steam turbine will drive a new electrical generator that produces 25 MW (net) of electricity. Steam cycle cooling will be accomplished with a new air cooled condenser (ACC). The fuel system for the CTG's will remain unchanged.

When operated with the OTSG's on, the plant will be a combined cycle plant, since the gas turbines and the steam turbine both turn electrical generators and produce power. The modified GWF Hanford plant will also retain the capability to operate in simple cycle mode. Under simple cycle operation, the OTSG's will be operated in a dry condition (no steam generation) and only the gas turbines will turn electrical generators and produce power. In either mode of operation, the turbine exhaust will be controlled by the SCR and oxidation catalyst systems.

After these modifications take place, the CTG's will be allowed to operate at any time, not just during periods of peak electricity demand. The facility has proposed an operating schedule of 1,350 hours of full load operation in simple cycle mode per year, 108 hours in simple cycle startup or shutdown mode, 6,650 hours of full load operation in combined cycle mode, 325 hours in combined cycle startup mode and 108 hours in combined cycle shutdown mode. GWF Hanford does not wish to be restricted to a specific number of hours at full load operation or startup/shutdown operation per calendar quarter. Actual emissions from the facility will vary depending on electricity demand from California. A hypothetical operating scenario has been developed for purposes of demonstrating that the project will comply with SJVAPCD emission offset requirements.

GWF Hanford – Proposed Hypothetical Operating Scenario (per unit)					
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Number of Simple Cycle Startup Hours	13	13	14	14	54
Number of Simple Cycle Shutdown Hours	13	13	14	14	54
Number of Simple Cycle Full Load Hours	337	337	338	338	1,350
Number of Combined Cycle Startup Hours	81	81	81	82	325
Number of Combined Cycle Shutdown Hours	27	27	27	27	108
Number of Combined Cycle Full Load Hours	1,662	1,662	1,663	1,663	6,650
Total Hours	2,133	2,133	2,137	2,138	8,541

The CTG's will utilize water injection into the combustors, evaporative cooling of the CTG inlet air, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.5 ppmvd @ 15% O_2 (simple cycle mode)
NO_X: 2.0 ppmvd @ 15% O_2 (combined cycle mode)
CO: 3.0 ppmvd @ 15% O_2 (either operating mode)
VOC: 2.0 ppmvd @ 15% O_2 (either operating mode)
PM_{10}: 2.20 lb/hr (either operating mode)
SO_X: 0.31 lb/hr (either operating mode)

A continuous emissions monitoring system (CEMS) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

V. EQUIPMENT LISTING:

<u>Pre-Project Equipment Descriptions:</u>

C-4140-1-3: 47.5 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION AND AN OXIDATION CATALYST

C-4140-2-3: 47.5 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION AND AN OXIDATION CATALYST

<u>Proposed Modifications</u>:

C-4140-1-5: MODIFICATION OF 47.5 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION AND AN OXIDATION CATALYST: CONVERT THE EXISTING POWER GENERATING SYSTEM TO A SIMPLE CYCLE OR COMBINED CYCLE CONFIGURATION BY (1) REMOVING THE EXISTING OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION SYSTEM AND 85' EXHAUST STACK; (2) INSTALLING A NEW ONCE THROUGH HEAT RECOVERY STEAM GENERATOR; (3) INSTALLING A NEW OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION SYSTEM AND 91.5' TALL EXHAUST STACK; AND (4) INSTALLING A 25 MW NOMINALLY RATED CONDENSING STEAM TURBINE GENERATOR AND ITS ASSOCIATED LUBE OIL COOLER (SHARED WITH C-4140-2)

C-4140-2-5: MODIFICATION OF 47.5 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION AND AN OXIDATION CATALYST: CONVERT THE EXISTING POWER GENERATING SYSTEM TO A SIMPLE CYCLE OR COMBINED CYCLE CONFIGURATION BY (1) REMOVING THE EXISTING OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION SYSTEM AND 85' EXHAUST STACK; (2) INSTALLING A NEW ONCE THROUGH HEAT RECOVERY STEAM GENERATOR; (3) INSTALLING A NEW OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION SYSTEM AND 91.5' TALL EXHAUST STACK; AND (4) INSTALLING A 25 MW NOMINALLY RATED CONDENSING STEAM TURBINE GENERATOR AND ITS ASSOCIATED LUBE OIL COOLER (SHARED WITH C-4140-1)

<u>Post Project Equipment Descriptions</u>:

C-4140-1-5: 47.5 MW NOMINALLY RATED SIMPLE-CYCLE OR COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AN OXIDATION CATALYST, ONCE THROUGH HEAT RECOVERY STEAM GENERATOR #1 (OTSG) AND A 25 MW NOMINALLY RATED STEAM TURBINE (SHARED WITH C-4140-2)

C-4140-2-5: 47.5 MW NOMINALLY RATED SIMPLE-CYCLE OR COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION, AN OXIDATION CATALYST, ONCE THROUGH HEAT RECOVERY STEAM GENERATOR #2 (OTSG) AND A 25 MW NOMINALLY RATED STEAM TURBINE (SHARED WITH C-4140-1)

C-4140-3-0: 460 BHP CUMMINS MODEL CFP15E-F10 TIER 3 CERTIFIED DIESEL-FIRED EMERGENCY INTERNAL COMBUSTION (IC) ENGINE POWERING A FIREWATER PUMP

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

C-4140-1 and '-2 (natural gas fired turbines):

NO_X, CO, VOC, PM_{10}, and SO_X are the primary pollutants created by the combustion of natural gas in the combustion turbine generators. The three primary forms of NO_X from combustion turbine generators are thermal NO_X, fuel NO_X and prompt NO_X.

Thermal NO_X is formed through the high temperature oxidation of the diatomic nitrogen found in combustion air. The formation of thermal NO_X 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 NO_X are:

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

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

Fuel NO_X is created by the conversion of fuel bound nitrogen into NO_X. During combustion, nitrogen bound in the fuel is released as a free radical and ultimately forms free N_2 or NO. Fuel NO_X 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 NO_X created is relatively small when compared to the quantity of thermal NO_X created.

Prompt NO_X is the third primary source of NO_X from combustion. Prompt NO_X 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 NO_X emissions from turbines is achieved through the use of both "front end" NO_X control technologies and "back end" NO_X technologies. Front end NO_X control technologies reduce the quantity of NO_X created during the combustion of the fuel. Since fuel NO_X is only a minor contributor to the overall NO_X emissions when combusting natural gas and prompt NO_X is difficult to control, front end control technologies primarily focus on limiting the production of thermal NO_X. The GE LM 6000 turbines currently permitted at this facility utilize a water spray pre-mix combustion system to reduce thermal NO_X emissions. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation.

Back end NO_X control technologies reduce the quantity of NO_X in the turbine exhaust via chemical reactions in the presence of a catalyst that convert NO_X into molecular nitrogen and water or convert NO_X into potassium nitrites and nitrates. The back end NO_X 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 once through heat recovery steam generator and reacts with nitrogen oxide molecules in the presence of a catalyst to form molecular nitrogen and water. The NO_X-ammonia reaction takes place over a limited temperature range (approximately 600 F to 750 F). Unreacted ammonia, an air contaminant, is exhausted from the SCR system (known as ammonia slip).

Pursuant to the applicant, the use of water spray pre-mix combustion technology and an SCR system will reduce NO_X emissions from GWF Hanford's combustion turbines below 2.5 ppmvd @ 15% O_2 (based on 1-hr standard) during simple cycle operation of the turbines and below 2.0 ppmvd @ 15% O_2 (based on 1-hr standard) during combined cycle operation of the turbines. The proposed maximum ammonia slip (NH_3) concentrations in the exhaust during simple cycle operation will be 10 ppmvd @ 15% O_2 and during combined cycle operation will be 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 3 ppmvd @ 15% O_2 (based on a 3-hour average) during either mode of 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 during either mode of operation of the turbines.

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 sulfur content of 0.24 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 an oxidation catalyst, which oxidizes 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 0.24 grains/scf and has proposed to limit ammonia slip emissions to 10 ppmvd NH_3 @ 15% O_2 during simple cycle operation and 5 ppmvd NH_3 @ 15% O_2 during combined cycle operation.

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.

<u>C-4140-3 (emergency IC engine):</u>

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

C-4140-1 and '-2 (natural gas fired turbines):

- The commissioning period will not exceed 430 hours and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.

- 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.

- When operating in simple cycle mode, the maximum daily emissions for each CTG will be estimated assuming two simple cycle startup events (2 x 10 minutes), two simple cycle shutdown events (2 x 10 minutes), 23.3 hours while firing at full load and the maximum full load emission factors.

- When operating in combined cycle mode, the maximum daily emissions for each CTG will be estimated assuming two simple cycle startup events (2 x 10 minutes), two combined cycle startup events (2 x 60 minutes), two simple cycle shutdown events (2 x 10 minutes), two combined cycle shutdown events (2 x 20 minutes), 20.7 hours while firing at full load and the maximum full load emission factors.

- When operating in simple cycle mode, the maximum annual emissions for each CTG are estimated assuming 325 simple cycle startup events (325 x 10 minutes), 325 simple cycle shutdown events (325 x 10 minutes), 1,350 hours while firing at full load and the average full load emission factors.

- When operating in combined cycle mode, the maximum annual emissions for each CTG are estimated assuming 325 combined cycle startup events (325 x 60 minutes), 325 simple cycle events (325 x 20 minutes), 6,650 hours while firing at full load and the average full load emission factors.

- Natural gas heating value used for calculation purposes will be 1,020 Btu/scf (per applicant)

C-4140-3 (emergency IC engine):

Emergency operating schedule:	24 hours/day
Non-emergency operating schedule:	up to 100 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:	commonly ≈ 35%

B. Emission Factors

Pre-Project Emission Factors:

C-4140-1 and '-2 (natural gas fired turbines):

The maximum simple cycle steady state air contaminant mass emission rates (lb/hr) and concentrations (ppmvd @ 15% O_2) were taken from the current permits for these turbines and are summarized below.

Simple Cycle Steady State Maximum Emission Rates and Concentrations						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rate (per turbine, lb/hr)	6.30	6.20	1.19	3.03	0.33	6.34*
ppmvd @ 15% O_2	3.7	6.0	2.0	--	--	10.0

*The permitted ppmvd NH_3 limit was converted to lb/hr using the following equation:

NH_3 PE= ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:

ppm is the emission concentration in ppmvd @ 15% O_2
MW is the molecular weight of the pollutant
MW_{NH3} = 17 lb/lb-mol
2.64 x 10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas (Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour (MMscf/hour)
O_2 is the stack oxygen content to which the emission concentrations are corrected (3%)

NH_3 PE (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu)
x 1,000 (Btu/scf) x 0.465 (MMscf/hr) x [20.9 / (20.9 – 15.0)]

The maximum NO_X and CO startup and shutdown emissions rates (lb/hr) were taken from the current permit. Pursuant to information in the facility files, the VOC, PM_{10} and SO_X emission rates during startup and shutdown are equivalent to the steady state emission rates listed above.

Simple Cycle Startup/Shutdown Emission Factors, Per Turbine					
	NO_X	CO	VOC	PM_{10}	SO_X
Startup (lb/event)	7.70	7.70	--	--	--
Shutdown (lb/event)	7.70	7.70	--	--	--
Startup (lb/hr)*	7.70	7.70	1.19	3.03	0.33
Shutdown (lb/hr)*	7.70	7.70	1.19	3.03	0.33

* Pursuant to the application review performed for the original permit action for the two natural gas fired turbine, a startup event was calculated to be one hour. Therefore, the NO_X and CO lb/event values are equivalent to the lb/hr values. In addition, the startup and shutdown VOC, PM_{10} and SO_X emission rates are equivalent to the steady state emission rates listed above.

<u>Post Project Emission Factors:</u>

<u>C-4140-1 and '-2 (natural gas fired turbines):</u>

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment D for manufacturer's commissioning period emission data) for the proposed CTG's are summarized below:

Commissioning Period Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	52.00	40.50	N/A[1]	N/A[1]	N/A[1]

The maximum and average simple cycle steady state air contaminant mass emission rates (lb/hr) and concentrations (ppmvd @ 15% O_2) estimated by the manufacturer for the proposed CTG's are summarized below (see Attachment E for manufacturer's emissions data):

Simple Cycle Steady State Emission Rates and Concentrations, Per Turbine						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Maximum Emission Rate (lb/hr)	4.24	3.10	1.20	2.20	0.31*	6.20
Maximum ppmvd @ 15% O_2 limits	2.5	3.0	2.0	--	--	10.0
Average Emission Rate (lb/hr)	4.24	1.80	0.50	2.20	0.31*	6.20
Average ppmvd @ 15% O_2 limits	2.5	1.8	0.8	--	--	10.0

* 0.24 ~~gr-S~~/100 ~~dscf~~ x 1 ~~lb-S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb-S~~ x 1 ~~scf~~/1020 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu x 465 MMBtu/hr = 0.31 lb/hr

The maximum and average combined cycle steady state air contaminant mass emission rates (lb/hr) and concentrations (ppmvd @ 15% O_2) estimated by the manufacturer for the proposed CTG's are summarized below (see Attachment E for manufacturer's emissions data):

Combined Cycle Steady State Emission Rates and Concentrations, per Turbine						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Maximum Emission Rate (lb/hr)	3.40	3.10	1.20	2.20	0.31*	3.10
Maximum ppmvd @ 15% O_2 limits	2.0	3.0	2.0	--	--	5.0
Average Emission Rate (lb/hr)	3.40	1.80	0.5	2.20	0.31*	3.10
Average ppmvd @ 15% O_2 limits	2.0	1.8	0.8	--	--	5.0

* 0.24 ~~gr-S~~/100 ~~dscf~~ x 1 ~~lb-S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb-S~~ x 1 ~~scf~~/1020 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu x 465 MMBtu/hr = 0.31 lb/hr

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

The maximum startup and shutdown emissions rates (lb/hr) estimated by the manufacturer for the proposed CTG's are summarized below (see Attachment E for manufacturer's startup and shutdown emissions data):

Simple Cycle Startup/Shutdown Emission Factors, Per Turbine					
	NO_X	CO	VOC	PM_{10}	SO_X
Startup (lb/event)	7.70	7.70	0.70	0.13	0.054
Shutdown (lb/event)	7.70	7.70	0.70	0.20	0.054
Startup (lb/hr)*	11.23	10.28	1.70	1.96	0.31
Shutdown (lb/hr)*	11.23	10.28	1.70	2.03	0.31

* Pursuant to the turbine vendor, "Each startup or shutdown event is estimated to be completed in 10 minutes; however, for simplification, the emissions for a startup/shutdown event are calculated as hourly emissions with the 10 minute startup/shutdown emissions being added to 50 minutes of base load operating emissions."

Combined Cycle Startup/Shutdown Emission Factors, Per Turbine					
	NO_X	CO	VOC	PM_{10}	SO_X
Startup (lb/event)	6.10	3.00	0.50	2.20	0.31
Shutdown (lb/event)	2.08	1.00	0.20	0.73	0.10
Startup (lb/hr)*	6.10	3.00	0.50	2.20	0.31
Shutdown (lb/hr)**	4.35	3.07	1.00	2.20	0.31

* Pursuant to the turbine vendor, "A startup event is estimated to be completed in 60 minutes". Therefore, the hourly startup emission rates will be set equal to the lb/event values and it will not be necessary to include additional operational time of base load combined cycle operation.

** Pursuant to the turbine vendor, "A shutdown event is estimated to be completed in 20 minutes; however, for simplification, the emissions for a startup/shutdown event are calculated as hourly emissions with the 20 minute shutdown emissions being added to 40 minutes of combined cycle base load operating emissions."

C-4140-3 (emergency IC engine):

Emergency IC Engine Emission Factors		
Pollutant	Emission Factor (g/bhp-hr)	Source
NO_X	2.66	Manufacturer Specifications
SO_X	0.0051	Mass Balance Equation Below
PM_{10}	0.078	Manufacturer Specifications
CO	0.671	Manufacturer Specifications
VOC	0.086	Manufacturer Specifications

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

C. Calculations

1. Pre-Project Potential to Emit (PE1)

C-4140-1 and '-2 (natural gas fired turbines):

a. Maximum Hourly PE

Simple Cycle Mode:

The maximum hourly potential to emit for NO_X and CO emissions will occur when each CTG is operating under startup or shutdown mode. Maximum hourly emissions for VOC, PM_{10}, SO_X, and NH_3 will occur when each CTG is operating at full load. The maximum hourly emissions are summarized in the table below.

Simple Cycle Maximum Hourly Potential to Emit, per Turbine				
	Startup Emissions (lb/hr)	Shutdown Emission (lb/hr)	Emissions Rate @ 100% Load (lb/hr)	Maximum Hourly PE (lb/hr)
NO_X	7.70	7.70	6.30	7.70
CO	7.70	7.70	6.20	7.70
VOC	N/A	N/A	1.19	1.19
PM_{10}	N/A	N/A	3.03	3.03
SO_X	N/A	N/A	0.33	0.33
NH_3	N/A	N/A	6.34	6.34

b. Maximum Daily PE

The following daily NO_X, CO, VOC, PM_{10} and SO_X emission rates were taken from the current permits for these CTG's. The following daily NH_3 emission rate was calculated using the hourly emission rate listed above and a worse case operating scenario of 24 hours per day.

Maximum Daily Potential to Emit	
	Daily PE, per Turbine (lb/day)
NO_X	151.5
CO	150.3
VOC	28.7
PM_{10}	72.8
SO_X	7.8
NH_3	152.2

c. Maximum Annual PE

The following annual NO_X, CO, VOC, PM_{10} and SO_X emission rates were taken from the current permits for these CTG's. The following annual NH_3 emission rate was calculated using the hourly emission rate listed above and the current permit operating limit of 8,000 hours per year.

Maximum Annual Potential to Emit	
	Annual PE, per Turbine (lb/year)
NO_X	52,314
CO	51,947
VOC	9,764
PM_{10}	25,176
SO_X	2,710
NH_3	50,720

C-4140-3 (emergency IC engine):

Section 3.27 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Since this diesel fired emergency IC engine is a new emission units, the pre-project potential to emit (PE1) will be set equal to zero and no further discussion is required.

2. Post Project Potential to Emit (PE2)

C-4140-1 and '-2 (natural gas fired turbines):

a. Maximum Hourly PE

Simple Cycle Mode:

The maximum hourly potential to emit for NO_X, CO, VOC and SO_X emissions will occur when each CTG is operating under startup or shutdown mode. Maximum hourly emissions for PM_{10} and NH_3 will occur when each CTG is operating at full load. The maximum hourly emissions are summarized in the table below.

Simple Cycle Maximum Hourly Potential to Emit, per Turbine				
	Startup Emissions (lb/hr)	Shutdown Emission (lb/hr)	Emissions Rate @ 100% Load (lb/hr)	Maximum Hourly PE (lb/hr)
NO_X	11.23	11.23	4.24	11.23
CO	10.28	10.28	3.10	10.28
VOC	1.70	1.70	1.20	1.70
PM_{10}	1.96	2.03	2.20	2.20
SO_X	0.31	0.31	0.31	0.31
NH_3	N/A	N/A	6.20	6.20

<u>Combined Cycle Mode:</u>

The maximum hourly potential to emit for NO_X emissions will occur when each CTG is operating under start-up mode. The maximum hourly potential to emit for SO_X emissions will occur when each CTG is operating under shutdown mode. Maximum hourly emissions for CO, VOC, PM_{10} and NH_3 will occur when each CTG is operating at full load. The maximum hourly emissions are summarized in the table below:

Combined Cycle Maximum Hourly Potential to Emit, per Turbine				
	Startup Emissions (lb/hr)	Shutdown Emission (lb/hr)	Emissions Rate @ 100% Load (lb/hr)	Maximum Hourly PE (lb/hr)
NO_X	6.10	4.35	3.40	6.10
CO	3.00	3.07	3.10	3.10
VOC	0.50	1.00	1.20	1.20
PM_{10}	2.20	2.20	2.20	2.20
SO_X	0.31	0.31	0.31	0.31
NH_3	N/A	N/A	3.10	3.10

b. Maximum Daily PE

<u>Simple Cycle Mode:</u>

Maximum simple cycle daily emissions for NO_X, CO, VOC, PM_{10} and SO_X emissions occurs when each CTG undergoes two (2) simple cycle startup events, two (2) simple cycle shutdown events and twenty three and 1/3 (23.33) hours operating at full load. Maximum daily emissions for PM_{10}, SO_X, and NH_3 occur when each CTG operates twenty-four (24) hours at full load. A sample calculation for NO_X emissions and the results for all pollutants are summarized below:

NO_X PE = [$EF_{startup}$ (lb/event) x 2 startups/day] + [$EF_{shutdown}$ (lb/event) x 2 shutdowns/day] + [$EF_{steady\ state}$ (lb/hr) x 23.33 hours/day]

NO_X PE = [7.70 lb/event x 2 startups/day] + [7.70 lb/event x 2 shutdowns/day] + [4.24 (lb/hr) x 23.33 hours/day]

NO_X PE = 129.7 lb/day

Simple Cycle Maximum Daily Potential to Emit, per Turbine				
	Simple Cycle Startup (lb/event)	Simple Cycle Shutdown (lb/event)	Emissions Rate @ 100% Load (lb/hr)	Daily PE (lb/day)
NO_X	7.70	7.70	4.24	129.7
CO	7.70	7.70	3.10	103.1
VOC	0.70	0.70	1.20	30.8
PM_{10}	0.13	0.20	2.20	52.0
SO_X	0.054	0.054	0.31	7.4
NH_3	N/A	N/A	6.20	148.8

Combined Cycle Mode:

GWF Hanford has indicated that a combined cycle startup and shutdown actually consists of a simple cycle startup or shutdown immediately followed by a combined cycle startup or shutdown. Therefore, the maximum combined cycle daily emissions for NO_X, CO, VOC, PM_{10} and SO_X emissions occurs when each CTG undergoes two (2) simple cycle startup events, two (2) combined cycle startup events, two (2) combined cycle shutdown events, two (2) simple cycle shutdown events and twenty and 2/3 (20.7) hours operating at full load. Maximum daily emissions for NH_3 occur when each CTG operates twenty-four (24) hours at full load. A sample calculation for NO_X emissions and the results for all pollutants are summarized below:

NO_X PE = [$EF_{\text{simple cycle startup}}$ (lb/event) x 2 startups/day] + [$EF_{\text{simple cycle shutdown}}$ (lb/event) x 2 shutdowns/day] + [$EF_{\text{combined cycle startup}}$ (lb/event) x 2 startups/day] + [$EF_{\text{combined cycle shutdown}}$ (lb/event) x 2 shutdowns/day] + [$EF_{\text{steady state}}$ (lb/hr) x 20.7 hours/day]

NO_X PE = [7.70 lb/event x 2 startups/day] + [7.70 (lb/event) x 2 shutdowns/day] + [6.10 (lb/event) x 2 startups/day] + [2.08 (lb/event) x 2 shutdowns/day] + [3.40 (lb/hr) x 20.7 hours/day]

NO_X PE = 117.5 lb/day

Combined Cycle Maximum Daily Potential to Emit, per Turbine						
	Simple Cycle Startup (lb/event)	Simple Cycle Shutdown (lb/event)	Combined Cycle Startup (lb/event)	Combined Cycle Shutdown (lb/event)	Emissions Rate @ 100% Load (lb/hr)	Daily PE (lb/day)
NO_X	7.70	7.70	6.10	2.08	3.40	117.5
CO	7.70	7.70	3.00	1.00	3.10	103.0
VOC	0.70	0.70	0.50	0.20	1.20	29.0
PM_{10}	0.13	0.20	2.20	0.73	2.20	52.1
SO_X	0.054	0.054	0.31	0.10	0.31	7.5
NH_3	N/A	N/A	N/A	N/A	3.10	74.4

c. *Maximum Annual PE*

Simple Cycle Mode:

Maximum simple cycle annual emissions for NO_X, CO, VOC, PM_{10} and SO_X emissions occurs when each CTG undergoes 325 startup events, 325 shutdown events and 1,350 hours operating at full load. Maximum annual emissions for NH_3 occur when each CTG operates 1,458.33 hours at full load. A sample calculation for NO_X emissions and the results for all pollutants are summarized below:

NO_X PE = [$EF_{startup}$ (lb/event) x 325 startups/year] + [$EF_{shutdown}$ (lb/event) x 325 shutdowns/year] + [$EF_{steady\ state}$ (lb/hr) x 1,350 hours/year]

NO_X PE = [7.70 lb/event x 325 startups/year] + [7.70 lb/event x 325 shutdowns/year] + [4.24 (lb/hr) x 1,350 hours/year]

NO_X PE = 10,729 lb/year

Simple Cycle Maximum Annual Potential to Emit, per Turbine				
	Simple Cycle Startup (lb/event)	Simple Cycle Shutdown (lb/event)	Average Emissions Rate @ 100% Load (lb/hr)	Annual PE (lb/year)
NO_X	7.70	7.70	4.24	10,729
CO	7.70	7.70	1.80	7,435
VOC	0.70	0.70	0.50	1,130
PM_{10}	0.13	0.20	2.20	3,077
SO_X	0.054	0.054	0.31	454
NH_3	N/A	N/A	6.20	9,042

Combined Cycle Mode:

Maximum combined cycle annual emissions for NO_X, CO, VOC, PM_{10} and SO_X emissions occurs when each CTG undergoes 325 startup events, 325 shutdown events and 6,650 hours operating at full load. Maximum annual emissions for NH_3 occur when each CTG operates 7,083.3 hours at full load. A sample calculation for NO_X emissions and the results for all pollutants are summarized below:

NO_X PE = [$EF_{startup}$ (lb/event) x 325 startups/year] + [$EF_{shutdown}$ (lb/event) x 325 shutdowns/year] + [$EF_{steady\ state}$ (lb/hr) x 6,650 hours/year]

NO_X PE = [6.10 lb/event x 325 startups/year] + [2.08 lb/event x 325 shutdowns/year] + [3.40 (lb/hr) x 6,650 hours/year]

NO_X PE = 25,269 lb/year

Combined Cycle Maximum Annual Potential to Emit, per Turbine				
	Combined Cycle Startup (lb/event)	Combined Cycle Shutdown (lb/event)	Average Emissions Rate @ 100% Load (lb/hr)	Annual PE (lb/year)
NO_X	6.10	2.08	3.40	25,269
CO	3.00	1.00	1.80	13,270
VOC	0.50	0.20	0.50	3,553
PM_{10}	2.20	0.73	2.20	15,582
SO_X	0.31	0.10	0.31	2,195
NH_3	N/A	N/A	3.10	21,958

Total Annual Emissions:

Total Annual Potential to Emit, per Turbine			
	Simple Cycle (lb/year)	Combined Cycle (lb/year)	Total Annual PE (lb/year)
NO_X	10,729	25,269	35,998
CO	7,435	13,270	20,705
VOC	1,130	3,553	4,683
PM_{10}	3,077	15,582	18,659
SO_X	454	2,195	2,649
NH_3	9,042	21,958	31,000

C-4140-3 (emergency IC engine):

The daily and annual PE are calculated as follows:

Emergency IC Engine Daily Potential to Emit					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Daily Hours of Operation (hr/day)	Conversion (g/lb)	PE2 Total (lb/day)
NO_X	2.66	460	24	453.6	64.7
CO	0.671	460	24	453.6	16.3
VOC	0.086	460	24	453.6	2.1
PM_{10}	0.078	460	24	453.6	1.9
SO_X	0.0051	460	24	453.6	0.1

Emergency IC Engine Annual Potential to Emit					
Pollutant	Emissions Factor (g/bhp-hr)	Rating (bhp)	Annual Hours of Operation (hrs/yr)	Conversion (g/lb)	PE2 Total (lb/yr)
NO_X	2.66	460	100	453.6	270
CO	0.671	460	100	453.6	68
VOC	0.086	460	100	453.6	9
PM_{10}	0.078	460	100	453.6	8
SO_X	0.0051	460	100	453.6	1

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

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

As discussed above, GWF Hanford is considered a part of the same stationary source as the existing Hanford LP facility (C-603) that is located right next to the proposed site. The SSPE1 values listed in the following table for GWF Hanford were taken from the PE values calculated above. The SSPE1 values listed in the following table for permit units C-603-2, '-3, '-6, '-13 and '-14 were taken from the application review performed under project 1043492 for this facility. The SSPE1 values listed in the following table for permit unit C-603-1 were taken from the application review performed under project 1092783. These facilities do not have any banked ERC's.

Pre-project Stationary Source Potential to Emit [SSPE1]					
Permit Unit	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
C-4140-1	52,314	51,947	9,764	25,176	2,710
C-4140-2	52,314	51,947	9,764	25,176	2,710
C-603-1	89,425	156,000	21,900	29,200	89,334
C-603-2	0	0	0	183	0
C-603-3	0	0	0	310	0
C-603-6	3,475	766	105	87	1,172
C-603-13	0	0	0	219	0
C-603-14	0	0	0	50	0
Pre-project SSPE (SSPE1)	197,528	260,660	41,533	80,401	95,926

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

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

Post Project Stationary Source Potential to Emit [SSPE2]					
Permit Unit	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
C-4140-1	35,998	20,705	4,683	18,659	2,649
C-4140-2	35,998	20,705	4,683	18,659	2,649
C-4140-3	270	68	9	8	1
C-603-1	89,425	156,000	21,900	29,200	89,334
C-603-2	0	0	0	183	0
C-603-3	0	0	0	310	0
C-603-6	3,475	766	105	87	1,172
C-603-13	0	0	0	219	0
C-603-14	0	0	0	50	0
Post Project SSPE (SSPE2)	165,166	198,244	31,380	67,375	95,805

5. Major Source Determination

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

Major Source Determination					
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
Post-project SSPE (SSPE2)	165,166	198,244	31,380	67,375	95,805
Major Source Threshold	50,000	200,000	50,000	140,000	140,000
Major Source?	Yes	No	No	No	No

6. Annual Baseline Emissions (BE)

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

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

otherwise,

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

As shown above, this facility is above the major source threshold for NO_X emissions. Per District Rule 2201, Section 3.12, a clean emissions unit is a 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 of achieved-in-practice (AIP) BACT during the five years immediately prior to the submission of the complete application.

AIP BACT for NO_X for simple cycle turbines rated at less than 50 MW during the five years prior to the submittal of GWF Hanford's application for this project was as follows:

NO_X: 5.0 ppmvd @ 15% O_2, based on a three-hour average (high temp SCR, or equal)

Condition 21 from the current permits for these turbines, C-4140-1-3 and '-2-3, requires that the emission rates from these turbines not exceed 3.7 ppmvd NO_X @ 15% O_2. GWF Hanford has demonstrated that the existing turbines have been in compliance with these emission limits with annual source testing and also the use of a NO_X continuous emission monitoring system. Therefore, both of these turbines can be considered clean emission units for the purposes of this project. The baseline NO_X emissions will be set equal to each of the turbine's pre-project potential to emit and no further discussion is required.

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 a Major Source for NO_X emissions. Therefore, a major modification can only be triggered for NO_X emissions.

The first step in determining whether this project triggers a major modification is to compare the sum of the post project potentials to emit for new unit and each unit modified within the project with the Major Modification significance thresholds listed in District Rule 2201, Table 3-3. If the sum of post project potentials to emit for each unit within the project 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. If the sum of the post project potentials to emit for each unit within the project is greater than the significance thresholds for NO_X, further investigation is required to determine whether the project is a major modification for NO_X.

Major Modification Thresholds (Existing Major Source)			
Pollutant	Post Project PE (lb/year)	Major Modification Threshold (lb/year)	Further Major Modification Calculations Necessary?
NO_X	72,266	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 a project is calculated as follows:

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

Since this facility currently operates two simple cycle natural gas fired turbines, the pre-project actual NO_X emissions will be based on the fuel usage records provided by the applicant for the two consecutive years of operation immediately prior to the submission of their complete applications for this project and their current permitted NO_X emission limit.

GWF Hanford's applications for this project were deemed complete in September of 2008. The fuel usage records provided by the applicant from September of 2006 through August of 2008 are shown in the table below (see fuel usage records provided by the applicant in Attachment M).

Actual Fuel Usage		
	Fuel Usage, C-4140-1 (MMscf/year)	Fuel Usage, C-4140-2 (MMscf/year)
Sep. '06 – Aug. '07	173.432	170.664
Sep. '07 – Aug. '08	101.710	106.205

GWF also provided data that showed that the average HHV of the natural gas burned in each of these turbines during that time frame was 1,070 Btu/scf. Based on information found in project C-1010451, the maximum heat input rating of each of the existing turbines is 459.6 MMBtu/hr. Therefore, the amount of hours that each turbine ran at 100% load is summarized in the table below.

Actual Operating Hours				
	Heat Input, C-4140-1 (MMBtu/year)	Heat Input, C-4140-2 (MMBtu/year)	Hours @ 100% Load, C-4140-1 (hr/year)	Hours @ 100% Load, C-4140-2 (hr/year)
Sep. '06 – Aug. '07	185,572	182,610	404	397
Sep. '07 – Aug. '08	108,830	113,639	237	247
Average	147,202	147,990	321	322

Using the maximum allowable NO_X emission rates, in lb/hr, from the current permit for each of these turbines, the actual pre-project NO_X emissions for this facility is as follows:

Actual NO_X Emissions			
	NO_X Emission Rate, per turbine (lb/hr)	Hours @ 100% Load, both turbines combined (hr/year)	Annual NO_X Emissions (lb/year)
Sep. '06 – Aug. '07	6.3	801	5,046
Sep. '07 – Aug. '08	6.3	484	3,049
Average	6.3	643	4,049

Therefore, as shown below, this project triggers a Major Modification for NO_X emissions.

Net Emissions Increase					
Pollutant	Project PE2 (lb/year)	Pre-Project Actual NO_X Emissions (lb/year)	Net Emissions Increase (lb/year)	Major Modification Threshold (lb/year)	Major Modification
NO_X	72,266	4,049	68,217	50,000	Yes

As shown above, this project triggers a major modification for NO_X emissions.

8. Federal Major Modification

District Rule 2201, Section 3.17 states that major modifications are also federal major modifications. Since the proposed project triggers a major modification for NO_X emissions, further calculations are necessary to determine whether the project triggers a Federal Major Modification for NO_X 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 worst case Net Emissions Increase for this project, GWF Hanford has requested that the projected actual NO_X emissions from each of the units within this project be set equal to each units 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 various discussion with Mark Kehoe of GWF, the actual fuel usage records provided for the two consecutive years of operation immediately prior to the submission of their complete applications for this project is reflective of the average operating schedule for this peaking power plant (September 2006 through August 2008). Therefore, the baseline actual emissions will be set equal to the actual emissions determined in the major modification section of this document above (refer to the baseline fuel usage records provided by the applicant in Attachment M).

In addition, GWF has also indicated that they do not see any reason why they would not actually operate the maximum number of hours the permit will allow. Therefore, the projected actual emissions for this facility will be set equal to each units post project potential to emit.

Net Emissions Increase					
Pollutant	Projected Actual NO_X Emissions (lb/year)	Baseline Actual NO_X Emissions (lb/year)	Net Emissions Increase (lb/year)	Threshold (lb/year)	Federal Major Modification?
NO_X	72,266	4,049	68,217	50,000	**Yes**

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

VIII. COMPLIANCE:

Rule 1080 Stack Monitoring

C-4140-1 and '-2 (natural gas fired turbines):

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEM's), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification. 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 and/or shutdown conditions, CEMS results during startup and shutdown events shall be replaced with startup and/or shutdown 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 (PS 2, 3 and 4), 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 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. 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(a)]

- The 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 60.4350(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 permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

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

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.

C-4140-1 and '-2 (natural gas fired turbines):

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

Proposed Rule 1081 Conditions:

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

- When operating in simple cycle mode and when operating in combined cycle mode, source testing to measure startup and shutdown NO_X, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-4140-1 or C-4140-2) within 60 days after the end of the commissioning period. [District Rules 1081 and 2201]

- Source testing to measure startup and shutdown NO_X, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-4140-1 or C-4140-2) at least once every seven years. CEM relative accuracy 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 or shutdown emission limits, then source testing to measure startup and shutdown NO_X and CO mass emission rates shall be conducted at least once every 12 months. If an annual startup and shutdown NO_X and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NO_X and CO testing frequency shall return to the once every seven years schedule. [District Rules 1081 and 2201]

- When operating in simple cycle mode, initial source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- When operating in combined cycle mode, initial source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- Source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- 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 and 40 CFR 60.4375(b)]

- The following test methods shall be used: NO_X - EPA Method 7E, 20, or ARB Method 100 (ppmv basis), or EPA Method 19 (lb/MMBtu basis); CO - EPA Method 10, 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM_{10} - EPA Method 5 and 202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, 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 40 CFR 60.4400(a)(2), (3), and (b)]

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.

C-4140-1 and '-2 (natural gas fired turbines):

GWF Hanford is subject to the requirements of this rule. The requirements of this Rule will be included in the operating permits. Continued compliance with this rule is anticipated.

Proposed Rule 1100 Conditions:

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

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

Rule 2010 Permits Required

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

Rule 2201 New and Modified Stationary Source Review Rule

A. Stationary Source Determination:

Pursuant to Section 3.37, a Stationary Source is defined as any building, structure, facility, or installation which emits or may emit any affected pollutant directly or as a fugitive emission. Building, structure, facility or installation includes all pollutant emitting activities including emissions units which:

- Are under the same or common ownership or operation, or which are owned or operated by entities which are under common control; and
- Belong to the same industrial grouping either by virtue of falling within the same two-digit standard industrial classification code or by virtue of being part of a common industrial process, manufacturing process, or connected process involving a common raw material; and
- Are located on one or more contiguous or adjacent properties; or
- Are located on one or more properties wholly within either the Western Kern County Oil Fields or the Central Kern County Oil Fields or Fresno County Oil Fields and are used for the production of light oil, heavy oil, or gas. Notwithstanding the provisions of this definition, light oil production, heavy oil production, and gas production shall constitute separate Stationary Sources

Hanford LP (Facility C-603) is an existing petroleum coke fired power plant located at 10596 Idaho Avenue in Hanford, CA. GWF Hanford (Facility C-4140) is located right next door to this existing facility, at 10550 Idaho Avenue in Hanford. Pursuant to information provided by the applicant for this project, GWF Energy, LLC, owns, or is at least a partial owner, of both of these two facilities. In addition, both of these facilities are power generating facilities that belong to the same two-digit standard industrial classification (SIC) code. Therefore, the emission units operated at these two sites meet the criteria specified above and are considered as a part of the same Stationary Source. The following condition will be included on each permit to ensure continued compliance with the requirements of this rule:

- District facilities C-603 and C-4140 are the same stationary source for District permitting purposes. [District Rule 2201]

B. 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

C-4140-1 and '-2 (natural gas fired turbines):

Simple Cycle Mode:

As discussed above, GWF Hanford is proposing to modify their existing simple cycle power plant arrangement to convert it to a simple cycle or combined cycle power plant arrangement. Due to the operational differences between a simple cycle plant and a combined cycle plant, the District will treat the addition of combined cycle operation as a new emission unit for the purposes of this project. Therefore, for the purposes of this project, there are no new emissions units associated with simple cycle mode; and BACT for new units with PE > 2 lb/day purposes is not triggered.

Combined Cycle Mode:

As discussed above, GWF Hanford is proposing to modify their existing simple cycle power plant arrangement to convert it to a simple cycle or combined cycle power plant arrangement. Due to the operational differences between a simple cycle plant and a combined cycle plant, the District will treat the addition of combined cycle operation as a new emission unit for the purposes of this project.

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install two new combined cycle combustion turbine generators with PE values greater than 2.0 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. Therefore, BACT is triggered for NO_X, VOC, PM_{10}, and SO_X emissions. However, since the SSPE2 for CO emissions is less than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document, BACT will not be required for CO emissions.

The PE of ammonia is greater than 2.0 pounds per day for each of the CTG's. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_X. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

C-4140-3 (emergency IC engine):

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install a new 460 bhp diesel fired emergency IC engine with PE values greater than 2.0 lb/day for NO_X, CO and VOC. Therefore, BACT is triggered for NO_X and VOC emissions. However, since the SSPE2 for CO emissions is less than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document, BACT will not be required for CO emissions.

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

As discussed above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

C-4140-1 and -2 (natural gas fired turbines):

Simple Cycle Mode:

AIPE = PE2 – HAPE

Where,
AIPE = Adjusted Increase in Permitted Emissions, (lb/day)
PE2 = Post-Project Potential to Emit, (lb/day)
HAPE = Historically Adjusted Potential to Emit, (lb/day)

HAPE = PE1 x (EF2/EF1)

Where,
PE1 = The emissions unit's Potential to Emit prior to modification or relocation, (lb/day)
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 = PE2 – (PE1 * (EF2 / EF1))

Simple Cycle AIPE, per Turbine					
	PE2* (lb/day)	PE1* (lb/day)	EF2 (lb/hr)	EF1 (lb/hr)	AIPE (lb/day)
NO_X	101.8	151.2	4.24	6.30	0.0
CO	74.4	148.8	3.10	6.20	0.0
VOC	28.8	28.6	1.20	1.19	0.2
PM_{10}	52.8	72.8	2.20	3.03	0.0
SO_X	7.4	7.8	0.31	0.33	0.1

*BACT for simple cycle turbines establishes operational conditions during steady state operation only. Therefore, for the purposes of the AIPE calculations performed for this project, the daily emission rates will be determined by taking the applicable steady emission factor and multiplying that by a worst case operating scenario of 24 hr/day (for example: NO_X PE2 = 4.24 lb/hr x 24 hr/day = 100.8 lb/day)

As demonstrated above, the AIPE is not greater than 2.0 lb/day for either of the turbines when operating in simple cycle mode. Therefore, BACT is not triggered for AIPE purposes of this project.

d. Major Modification

As discussed in Section VII.C.7 above, this project does constitute a Major Modification for NO_X emissions; therefore BACT is triggered for NO_X for all emissions units associated with this stationary source project.

2. BACT Guidance

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

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

C-4140-1 and '-2 (natural gas fired turbines):

Simple Cycle Mode:

BACT Guideline 3.4.8, 3rd quarter 2008, applies to gas turbines rated at less than 50 MW, without heat recovery. When operating in simple cycle mode, GWF Hanford is proposing to operate two 47.5 MW gas turbines without heat recovery. Therefore, BACT Guideline 3.4.8 is applicable to each of the two CTG's and no further discussion is required (BACT Guideline 3.4.8 included in Attachment F).

Combined Cycle Mode:

BACT Guideline 3.4.6, 3rd quarter 2008, applies to gas turbines rated at less than 50 MW, with heat recovery. When operating in combined cycle mode, GWF Hanford is proposing to operate two 47.5 MW gas turbines with once through heat recovery steam generators and a 25 MW steam turbine. Therefore, BACT Guideline 3.4.6 is applicable to each of the two CTG's and no further discussion is required (BACT Guideline 3.4.6 included in Attachment F).

C-4140-3 (emergency IC engine):

BACT Guideline 3.1.4, 3rd quarter 2008, applies to diesel-fired emergency internal combustion engines powering fire pumps. GWF Hanford is proposing to operate one 460 bhp diesel fired emergency internal combustion engine powering a firewater pump. Therefore, BACT Guideline 3.1.4 is applicable to this emergency internal combustion engine and no further discussion is required (BACT Guideline 3.1.4 included in Attachment F).

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.

C-4140-1 and '-2 (natural gas fired turbines):

Simple Cycle Mode:

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

NO_X: 2.5 ppmv @ 15% O_2 (1-hour rolling average, except during startup/shutdown) with water injection, SCR with ammonia injection and natural gas fuel

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]
- 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 permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]
- When operating in simple cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 4.24 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

Combined Cycle Mode:

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

Steady State Operation:

NO_X: 2.0 ppmv @ 15% O_2 (1-hour rolling average, except during startup/shutdown) with water or steam injection and SCONOx, or equal

Startup and Shutdown Periods:

NO_X: SCR System Operation with NH_3 Injection at Feasible Catalyst Temperatures during Startup and Shutdown Periods

Steady State Operation and Startup and Shutdown Periods:

VOC: 2.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with oxidation catalyst, or equal

PM_{10}: Air inlet cooler/filter, lube oil vent coalescer and either PUC regulated natural gas or non- PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal

SO_X: PUC-regulated natural gas or Non-PUC-regulated gas with no more that 0.75 gr 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]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rules 2201 and 4703]

- 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 permittee 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]

- 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]

- When operating in combined cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 3.40 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

- When operating in combined cycle mode, during start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 6.10 lb/event; CO – 3.00 lb/event; VOC (as methane) – 0.50 lb/event; PM_{10} – 2.20 lb/event; or SO_X (as SO_2) – 0.31 lb/event. [District Rules 2201 and 4703]

- When operating in combined cycle mode, during shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 2.08 lb/event; CO – 1.00 lb/event; VOC (as methane) – 0.20 lb/event; PM_{10} – 0.73 lb/event; or SO_X (as SO_2) – 0.10 lb/event. [District Rules 2201 and 4703]

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 0.24 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rules 2201 and 4801, Kings County Rule 407, and 40 CFR 60.4330(a)(2)]

C-4140-3 (emergency IC engine):

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

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

VOC: Positive crankcase ventilation

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: 2.66 g-NO_X/bhp-hr, 0.671 g-CO/bhp-hr, or 0.086 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- This engine shall be equipped with either a positive crankcase ventilation (PCV) system which 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]

C. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_X and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_X and 29,200 lbs/year for PM_{10}. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_X 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)	165,166	198,244	31,380	67,375	95,805
Offset Threshold	20,000	200,000	20,000	29,200	54,750
Offsets Required?	Yes	No	Yes	Yes	Yes

2. Quantity of Offsets Required:

Per Section 4.7.2, 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) = $(\Sigma[PE2 - BE] + ICCE) \times DOR$, for all new or modified emissions units in the project,

Where,
PE2 = Post Project Potential to Emit, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit unit C-4140-3-0 will be exempt from providing offsets and the emissions associated with this permit unit contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

NO_X Emissions:

Since the facility NO_X emissions are above the offset threshold, the amount of offsets to be required will be determined using the following calculation:

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR

Offsets Required = $[(PE2 - BE)_{C\text{-}4140\text{-}1} + (PE2 - BE)_{C\text{-}4140\text{-}2}]$ x DOR

Offsets Required = $[(35{,}988 - 52{,}314)_{\text{-}1} + (35{,}988 - 52{,}314)_{\text{-}2}]$ x DOR

Offsets Required = 0 lb-NO_X/year

Therefore, offsets are not required and no further discussion is required.

VOC Emissions:

Since the facility VOC emissions are above the offset threshold, the amount of offsets to be required will be determined using the following calculation:

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR

Offsets Required = $[(PE2 - BE)_{C\text{-}4140\text{-}1} + (PE2 - BE)_{C\text{-}4140\text{-}2}]$ x DOR

Offsets Required = $[(4{,}683 - 9{,}764)_{\text{-}1} + (4{,}683 - 9{,}764)_{\text{-}2}]$ x DOR

Offsets Required = 0 lb-VOC/year

Therefore, offsets are not required and no further discussion is required.

PM_{10} Emissions:

Since the facility PM_{10} emissions are above the offset threshold, the amount of offsets to be required will be determined using the following calculation:

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR

Offsets Required = $[(PE2 - BE)_{C\text{-}4140\text{-}1} + (PE2 - BE)_{C\text{-}4140\text{-}2}]$ x DOR

Offsets Required = $[(18{,}659 - 25{,}176)_{\text{-}1} + (18{,}659 - 25{,}176)_{\text{-}2}]$ x DOR

Offsets Required = 0 lb-PM_{10}/year

Therefore, offsets are not required and no further discussion is required.

SO_X Emissions:

Since the facility SO_X emissions are above the offset threshold, the amount of offsets to be required will be determined using the following calculation:

Offsets Required (lb/year) = $(\Sigma[PE2 - BE] + ICCE) \times DOR$

Offsets Required = $[(PE2 - BE)_{C\text{-}4140\text{-}1} + (PE2 - BE)_{C\text{-}4140\text{-}2}] \times DOR$

Offsets Required = $[(2{,}649 - 2{,}710)_{\text{-}1} + (2{,}649 - 2{,}710)_{\text{-}2}] \times DOR$

Offsets Required = 0 lb-SO_X/year

Therefore, offsets are not required and no further discussion is required.

D. Public Notification:

1. Applicability

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

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

a. New Major Source Notice Determination

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

b. Major Modification

As demonstrated in VII.C.7, this project is a Major Modification for NO_X emissions. 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. As seen in Section VII.C.2 above, this project does not include a new emissions unit which has daily emissions greater than 100 lb/day for any pollutant. Therefore, public noticing is not required for this project for Potential to Emit 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	197,528	165,166	20,000 lb/year	No
CO	260,660	198,244	200,000 lb/year	No
VOC	41,533	31,380	20,000 lb/year	No
PM_{10}	80,401	67,375	29,200 lb/year	No
SO_X	95,926	95,805	54,750 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore 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	165,166	197,528	-32,362	20,000 lb/year	No
CO	198,244	260,660	-62,416	20,000 lb/year	No
VOC	31,380	41,533	-10,153	20,000 lb/year	No
PM_{10}	67,375	80,401	-13,026	20,000 lb/year	No
SO_X	95,805	95,926	-121	20,000 lb/year	No

As demonstrated above, the SSIPE's for all pollutants were less than 20,000 lb/year; 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 (i.e. major modification), the District shall public notice this project according to the requirements of Section 5.5.

E. Daily Emission Limits:

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

C-4140-1 and '-2 (natural gas fired turbines):

Simple Cycle Mode:

- When operating in simple cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 4.24 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

- When operating in simple cycle mode, during start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 7.70 lb/event; CO – 7.70 lb/event; VOC (as methane) – 0.70 lb/event; PM_{10} – 0.13 lb/event; or SO_X (as SO_2) – 0.054 lb/event. [District Rules 2201 and 4703]

- When operating in simple cycle mode, during shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 7.70 lb/event; CO – 7.70 lb/event; VOC (as methane) – 0.70 lb/event; PM_{10} – 0.20 lb/event; or SO_X (as SO_2) – 0.054 lb/event. [District Rules 2201 and 4703]

- When operating in simple cycle mode, the ammonia (NH_3) emissions shall not exceed either of the following limits: 6.20 lb/hr or 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

<u>Combined Cycle Mode:</u>

For the turbines, the DEL's 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:

- When operating in combined cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 3.40 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

- When operating in combined cycle mode, during start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 6.10 lb/event; CO – 3.00 lb/event; VOC (as methane) – 0.50 lb/event; PM_{10} – 2.20 lb/event; or SO_X (as SO_2) – 0.31 lb/event. [District Rules 2201 and 4703]

- When operating in combined cycle mode, during shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 2.08 lb/event; CO – 1.00 lb/event; VOC (as methane) – 0.20 lb/event; PM_{10} – 0.73 lb/event; or SO_X (as SO_2) – 0.10 lb/event. [District Rules 2201 and 4703]

- When operating in combined cycle mode, the ammonia (NH_3) emissions shall not exceed either of the following limits: 3.10 lb/hr or 5 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

Either Operating Mode:

- 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 permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

- Maximum daily emissions from this CTG shall not exceed any of the following limits: NO_X (as NO_2) – 129.7 lb/day; CO – 103.1 lb/day; VOC – 30.8 lb/day; PM_{10} – 52.1 lb/day; or SO_X (as SO_2) – 7.5 lb/day. [District Rule 2201]

- This CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 0.24 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [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:

- Maximum annual emissions from this CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 35,998 lb/year; CO – 20,705 lb/year; VOC – 4,683 lb/year; PM_{10} – 18,660 lb/year; or SO_X (as SO_2) – 2,649 lb/year. [District Rule 2201]

- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

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. Compliance Certification:

Section 4.15.2 of this Rule requires the owner of a new Major Source or a source undergoing a Federal 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 or are on a schedule for compliance with all applicable emission limitations and standards. As discussed in Sections VIII-Rule 2201-C.1.a and VIII-Rule 2201-C.1.b, this project does constitute a Federal Major Modification, therefore this requirement is applicable. GWF Power Systems statewide compliance certification is included in Attachment K.

H. Air Quality Impact Analysis:

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

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

AAQA Results Summary					
Pollutant	1 hr Average	3 hr Average	8 hr Average	24 hr Average	Annual Average
CO	Pass	N/A	Pass	N/A	N/A
NO_x	Pass	N/A	N/A	N/A	Pass
SO_x	Pass	Pass	N/A	Pass	Pass

The proposed location is in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	0.71	3.19	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

I. Compliance Assurance:

1. Source Testing

C-4140-1 and '-2 (natural gas fired turbines):

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, dated 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 is 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.

As discussed above, GWF Hanford will consist of two GE, model LM 6000 PC Sprint, gas turbine generator units. Typically, a power plant is permitted to only operate in one mode, simple cycle or combined cycle. Power plants then perform a source test at least once every 12 months on a turbine when it is operating in its permitted operational mode. GWF Hanford will primarily be operating in combined cycle mode with the gas turbines and steam turbine producing electrical power. GWF Hanford will have the ability to operate in simple cycle mode as well where only the gas turbines producing electrical power. Depending on the demand for power at any given time of the year, it may not always be feasible for GWF Hanford to operate the turbines at this facility in combined cycle mode or simple cycle mode for the purposes of performing their annual source test. In addition, the CEMS will be certified to measure the actual NO_X and CO emissions from the gas turbines during either mode of operation. Therefore, the District will allow GWF Hanford to perform one annual source test while the turbines are operating in either combined cycle mode or simple cycle mode, whichever mode of operation is required by their power purchase agreement at the time of the source test.

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

- When operating in simple cycle mode, initial source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- When operating in combined cycle mode, initial source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- Source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

In addition, source testing of NO_X, CO and VOC startup and shutdown emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. If CEM data is not certifiable to determine compliance with NO_X and CO startup emission limits, then source testing to measure startup NO_X and CO mass emission rates shall be conducted at least once every 12 months. 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 measures startup emissions.

- When operating in simple cycle mode and when operating in combined cycle mode, source testing to measure startup and shutdown NO_X, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-4140-1 or C-4140-2) within 60 days after the end of the commissioning period. [District Rules 1081 and 2201]

- Source testing to measure startup and shutdown NO_X, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-4140-1 or C-4140-2) at least once every seven years. CEM relative accuracy 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 or shutdown emission limits, then source testing to measure startup and shutdown NO_X and CO mass emission rates shall be conducted at least once every 12 months. If an annual startup and shutdown NO_X and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NO_X and CO testing frequency shall return to the once every seven years schedule. [District Rules 1081 and 2201]

Each turbine exhaust stack will be equipped with CEMs for NO_X, CO, and O_2. The CEM's will take readings while the CTG's are operating in either simple cycle mode or combined cycle mode. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

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

C-4140-3 (emergency IC engine):

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

2. Monitoring

C-4140-1 and '-2 (natural gas fired turbines):

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. GWF Hanford has indicated that the results of their previous fuel sulfur content test results have shown that the natural gas used as this facility will have a sulfur content of up less than or equal to 0.24 gr/100 scf. GWF has agreed to the continue to physically monitor the fuel sulfur content weekly for eight consecutive weeks and quarterly thereafter if the fuel sulfur content remains below 0.24 gr/100 scf. GWF Hanford will be operating these turbines in compliance with the fuel sulfur content monitoring requirements as described in the Rule 4001, Subpart KKKK discussion below. Therefore, compliance with the monitoring requirements will be satisfied.

C-4101-3 (emergency IC engine):

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

C-4140-1 and '-2 (natural gas fired turbines):

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to the section VIII, Rule 4703 compliance discussion of this document for a discussion of the parameters that will be monitored and the records that will be maintained.

C-4140-3 (emergency IC engine):

No recordkeeping is required to demonstrate compliance with Rule 2201. However, this IC engine is subject to the recordkeeping requirements specified in District Rule 4702, *Stationary Internal Combustion Engines - Phase 2.* Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation below.

4. Reporting

C-4140-1 and '-2 (natural gas fired turbines):

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.

C-4140-3 (emergency IC 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."

Section 3.20.5 states that a minor permit modification is a permit modification that does not meet the definition of modification as given in Section 111 or Section 112 of the Federal Clean Air Act. Since this project involves the modification of two existing turbines and the project results in a federal major modification for NO_X emissions, the proposed project is considered to be a modification under the Federal Clean Air Act. As a result, the proposed project constitutes a Significant Modification to the Title V Permit pursuant to Section 3.29 of this rule.

As discussed above, the facility has applied for a Certificate of Conformity (COC) along with this project. Therefore, the facility must apply to modify their Title V permit with an administrative amendment, prior to operating with the proposed modifications. Continued compliance with this rule is expected. The facility shall not implement the changes requested until the final permit is issued.

- 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 Rule 2201]

- 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

<u>*C-4140-1 and '-2 (natural gas fired turbines):*</u>

This rule incorporates the requirements of the Acid Rain Standards Part 72, Title 40, Code of Federal Regulations. Based on information found in the facility files, the existing turbines operated at this facility were determined to be subject to the acid rain program as phase II units since each turbine has a generator nameplate rating of greater than 25 MW and was originally installed after November 15, 1990.

The acid rain program will be implemented through GWF Hanford's Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. GWF Hanford has indicated that they applied to comply with the acid rain requirements through the Environmental Protection Agency (EPA) prior to initial operation of the turbines at this facility (reference ORIS code 55698). However, even though GWF Hanford applied for approval of the acid rain provisions through EPA, an application requesting that the conditions be added to their Title V permit was never submitted to the District. Therefore, the acid rain conditions will be added as a part of this project.

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

The following conditions will be added to the turbine permits at this time and will ensure that GWF Hanford is in continued compliance with the requirements of the acid rain program:

- 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 and 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 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 superseded 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 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 at major air toxics sources with Authorities to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[1]

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.

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

The applicant has supplied the following data.

Hazardous Air Pollutant Emissions
GWF Hanford – GE LM6000 PC Sprint Turbines

Hazardous Air Pollutant	Emission Factor (lb/MMSCF)[1]	Maximum Hourly Emissions per Turbine (lb/hr)[2]	Maximum Annual Emissions per Turbine (lb/yr)[3]	Maximum Annual Emissions, Two Turbines (lb/yr)
Acetaldehyde	1.37E-01	6.25E-02	534	1,068
Acrolein	1.89E-02	8.61E-03	74	148
Benzene	1.33E-02	6.06E-03	52	104
1,3 Butadine	1.27E-04	5.79E-05	0.5	1
Ethylbenzene	1.79E-02	8.16E-03	70	140
Formaldehyde	9.17E-01	4.18E-01	3,570	7,140
Hexane	2.59E-01	1.18E-01	1,008	2,016
Naphthalene	1.66E-03	7.57E-04	6	12
PAH's[4]	1.4E-05	6.38E-06	0.1	0.2
Propylene	7.71E-01	3.52E-01	3,006	6,012
Propylene Oxide	4.78E-02	2.18E-02	186	372
Toluene	7.1E-02	3.24E-02	277	554
Xylene	2.61E-02	1.19E-02	102	204
Total			**8,886**	**17,771**

1 Emission factors taken from the California Air Toxics Emission Factors (CATEF) database.
2 Based on a maximum hourly turbine heat input of 465 MMBtu/hr and a fuel HHV of 1,020 Btu/scf. (0.456 MMscf/hr)
3 Based on a maximum annual turbine operating schedule of 8,541 hours/year.
4 Carcinogenic PAH's only; naphthalene considered separately. Emission Factor based on two separate source tests (2002 and 2004) from the Delta Energy Center located in Pittsburg, CA.

Hazardous Air Pollutant Emissions
GWF Hanford – Diesel Fired Emergency Firewater Pump Engine

Hazardous Air Pollutant	Emission Factor (lb/1,000 gallons)[1]	Maximum Hourly Emissions per Turbine (lb/hr)[2]	Maximum Annual Emissions (lb/yr)[3]
Benzene	1.863E-01	4.19E-03	0.42
Formaldehyde	1.761	3.96E-02	4.0
PAH's - Naphthalene	5.59E-02	1.26E-03	0.13
Naphthalene	1.97E-04	4.43E-06	0.00044
Acetaldehyde	7.833E-01	1.76E-02	1.8
Acrolein	3.39E-02	7.63E-04	0.076
1,3 Butadiene	2.174E-01	4.89E-03	0.49
Chlorobenzene	2.0E-04	4.50E-06	0.00045
Dioxins	ND	ND	ND
Furans	ND	ND	ND
Propylene	4.67E-01	1.05E-02	1.05
Hexane	2.69E-02	6.05E-04	0.061
Toluene	1.054E-01	2.37E-03	0.237
Xylenes	4.24E-02	9.54E-04	0.095
Ethyl Benzene	1.09E-02	2.45E-04	0.025
Hydrogen Chloride	1.863E-01	4.19E-03	0.419

Arsenic	1.60E-03	3.6E-05	0.004
Beryllium	ND	ND	ND
Cadmium	1.50E-03	3.38E-05	0.003
Total Chromium	6.0E-04	1.35E-05	0.001
Hexavalent Chromium	1.0E-04	2.25E-06	0.0002
Copper	4.1E-03	9.23E-05	0.009
Lead	8.3E-03	1.87E-04	0.0187
Manganese	3.1E-03	6.98E-05	0.0070
Mercury	2.0E-03	4.50E-05	0.0045
Nickel	3.9E-03	8.78E-05	0.0088
Selenium	2.2E-03	4.95E-05	0.00495
Zinc	2.24E-02	5.04E-04	0.0504
Total			**9.0**

1 Emission factors taken from the California Air Toxics Emission Factors (CATEF) database.
2 Based on a maximum hourly fuel usage rate of 22.5 gallons.
3 Based on a maximum annual turbine operating schedule of 100 hours/year for maintenance and testing purposes.

As shown in the tables above, GWF Hanford's emissions of each individual HAP are below 10 tons per year and the overall total HAP emissions are below 25 tons per year. Therefore, this facility will not be a major air toxics source and the provisions of this rule do not apply.

Rule 4001 New Source Performance Standards

C-4140-1 and '-2 (natural gas fired turbines):

40 CFR 60 – Subpart GG

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. GWF Hanford originally constructed and installed the simple cycle turbines operating at this power plant in 2002. Therefore, these turbines meet the applicability requirements of this subpart.

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

40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The gas turbines involved in this project have a rating of 465 MMBtu/hr and were originally installed in August of 2002. However as a part of this project, GWF Hanford is proposing to modify the simple cycle power plant arrangement to convert the plant to a simple cycle and combined cycle power plant arrangement. Therefore, the District will consider these turbines as being modified and/or reconstructed after February 18, 2005 and the requirements of this subpart will apply to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new turbines firing natural gas with a combustion turbine heat input at peak load of greater than 50 MMBtu/hr but less than or equal to 850 MMBtu/hr shall meet a NO_X emissions limit of 25 ppmvd @ 15% O_2 or 150 ng/J of useful output (1.2 lb/MWh).

GWF Hanford is proposing a NO_X emission concentration limit of 2.5 ppmvd @ 15% O_2 for each turbine while operating in simple cycle mode and a NO_X emission concentration limit of 2.0 ppmvd @ 15% O_2 for each turbine while operating in combined cycle mode. 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:

- When operating in simple cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 4.24 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

- When operating in combined cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 3.40 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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 Power is proposing to burn PUC-regulated natural gas fuel in each of these turbines with a maximum sulfur content of 0.24 grains/ 100 dscf (0.000684 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:

- This CTG shall be fried exclusively on PUC-regulated natural gas with a sulfur content of no greater than 0.24 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

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

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

Paragraph (b) states that alternatively, an operator may use continuous emission monitoring, as follows:

(1) Install, certify, maintain and operate a continuous emissions monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and
(2) For units complying with the output-based standard, install, calibrate, maintain and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and
(3) For units complying with the output based standard, install, calibrate, maintain and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and
(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

GWF Hanford will operate each of these turbines with water injection. They are proposing to install, certify, maintain and operate a CEMS consisting of a NO_X monitor and an O_2 monitor to determine hourly NO_X emission rate in ppm. They are not proposing to comply with the output-based NO_X emission standards listed in Table 1. Therefore, the proposed CEMS satisfies the requirements of this section. 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 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 and/or shutdown conditions, CEMS results during startup and shutdown events shall be replaced with startup and/or shutdown 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)]

<u>Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:</u>

This section specifies the requirements for units not equipped with water or steam injection. As discussed above, GWF Hanford is proposing to use water injection to reduce NO_X emissions in each of these turbines. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4345 – CEMS Equipment Requirements:

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

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

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

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

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

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

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F, Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2) or 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 develop and keep on site a quality assurance plan the NO_X CEMS. [40 CFR 60.4345(e)]

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

Section 60.4350 states that for purposes of identifying excess emissions:

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

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

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

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

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

(g) For simple cycle units without heat recovery, use the calculated hourly average emissions rates from paragraph (f) of this section to assess excess emissions on a 4-hour average basis.

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis.

GWF Hanford 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 conditions will ensure continued compliance with the requirements of this section:

- 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 60.4350(a)]

- For the purpose of determining excess NO_X emission, 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 NO_X emission rate in units of ppm, using the appropriate equation from method 19 of 40 CFR 60, Appendix A. For any hour in which the hourly O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations. [40 CFR 60.4350(b) and 60.4350(f)]

- When operating in simple cycle mode, excess NO_X emissions shall be defined as any operating hour in which the 1-hour rolling average NO_X concentration exceeds an applicable emissions limit. When operating in combined cycle mode, excess NO_X emissions shall be defined as any 30 day operating period in which the 30 day rolling average NO_X concentration exceeds an applicable emissions limit. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O_2 (or both). [40 CFR 60.4350(g), 40 CFR 60.4350(h) and 40 CFR 60.4380(b)(1)]

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

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 Hanford is proposing to install a 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 Hanford is proposing to operate these turbines on PUC-regulated natural gas that has a maximum sulfur content of 0.24 grains/100 scf. Primarily, the natural gas supplier would only be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates that the natural gas sulfur content is less than or equal to 1.0 grains/100 scf. Therefore, GWF Hanford has requested the option to physically monitor the sulfur content be incorporated into their permit.

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

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

GWF Hanford is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every calendar quarter. If any quarterly monitoring period shows an exceedance, weekly monitoring shall resume. GWF Hanford is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for these turbines. The following condition will ensure continued compliance with the requirements of this section:

- Testing to demonstrate compliance with the fuel sulfur content limit of 0.24 grains of sulfur compounds (as S) per 100 dry scf of natural gas 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 the 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. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

<u>Section 60.4380 – Excess NO_X Emissions:</u>

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 Hanford 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 CEMS:

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

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

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

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. GWF Hanford 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:

- When operating in simple cycle mode, excess NO_X emissions shall be defined as any operating hour in which the 1-hour rolling average NO_X concentration exceeds an applicable emissions limit. When operating in combined cycle mode, excess NO_X emissions shall be defined as any 30 day operating period in which the 30 day rolling average NO_X concentration exceeds an applicable emissions limit. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O_2 (or both). [40 CFR 60.4350(g), 40 CFR 60.4350(h) and 40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

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

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

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

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

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

- Excess SO_X 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 SO_X begins when a sample is not taken by its due date. A period of monitor downtime for SO_X also begins on the date and hour of a required sample, if invalid results are obtained. A period of SO_X monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)]

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. GWF Hanford 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 30^{th} day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

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

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

GWF Hanford 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 determine compliance with the NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- The following test methods shall be used: NO_X - EPA Method 7E, 20, or ARB Method 100 (ppmv basis), or EPA Method 19 (lb/MMBtu basis); CO - EPA Method 10, 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM_{10} - EPA Method 5 and 202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, 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 40 CFR 60.4400(a)(2), (3), and (b)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

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

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, GWF Hanford 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 Hanford is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

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

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. GWF Hanford 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.

C-4140-3 (emergency IC engine):

40 CFR 60 – Subpart IIII

Applicability

Section 60.4200 states that this subpart is applicable to owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

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

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

Emission Standards

Section 60.4205(c) states that fire-pump engines with a displacement less than 30 liters/cylinder must comply with the following emission standards based on the model year and maximum HP rating of the engine:

Engine HP Rating	Model Year	NMHC + NOx (g/bhp-hr)	CO (g/bhp-hr)	PM (g/ghp-hr)	Equivalent Tier Standard
50 ≤ HP < 100	2010 and earlier	7.8	3.7	0.6	N/A
	2011+ (1)	3.5	N/A	0.3	Tier 3
100 ≤ HP < 175	2009 and earlier	7.8	3.7	0.6	N/A
	2010+ (2)	3.0	N/A	0.22	Tier 3
175 ≤ HP < 600	2008 and earlier	7.8	2.6	0.4	N/A
	2009+ (3)	3.0	N/A	0.15	Tier 3
600 ≤ HP ≤ 750	2008 and earlier	7.8	2.6	0.4	N/A
	2009+	3.0	N/A	0.15	Tier 3
HP > 750	2007 and earlier	7.8	2.6	0.4	N/A
	2008+	4.8	N/A	0.15	Tier 3

(1) For model years 2011 – 2013, engines in this power category with a rated speed of greater than 2650 RPM may comply with emission limitations for 2010 and earlier engines.
(2) For model years 2010 – 2012, engines in this power category with a rated speed of greater than 2650 RPM may comply with the emission limitations for 2009 and earlier engines.
(3) For model years 2009 – 2011, engines in this power category with a rated speed of greater than 2650 RPM may comply with the emission limitations for 2009 and earlier engines.

As discussed above, GWF Hanford is proposing to install a new 460 bhp diesel fired emergency internal combustion engine powering a fire water pump. The new engine will be a 2009 model year or later Tier III certified diesel fired IC engine. The emission factors from the proposed the engine are as follows:

- NO_X + VOC emission factor is 2.746 grams/bhp-hr, and
- CO emission factor is 0.671 grams/bhp-hr, and
- PM emission factor is 0.078 grams/bhp-hr.

Therefore, compliance with the requirements of this section is expected. The following conditions will ensure continued compliance:

- Emissions from this IC engine shall not exceed any of the following limits: 2.66 g-NO_X/bhp-hr, 0.671 g-CO/bhp-hr, or 0.086 g-VOC/bhp-hr. [District Rule 2201, 40 CFR 60.4205(c), 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.078 g-PM_{10}/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102, 40 CFR 60.4205(c), 13 CCR 2423 and 17 CCR 93115]

Fuel Requirements

Section 60.4207 requires that owners/operators of diesel fired internal combustion engines must use diesel fuel that meets the requirements of 40 CFR 80.510(a), beginning October 1, 2007, and 40 CFR 80.510(b), beginning October 1, 2010. 40 CFR 81.510(b) requires that all diesel fired non-road engines must be fired on diesel fuel with a sulfur content of 15 ppm , or less, and have a minimum centane index of 40 or a maximum aromatic content of 35 percent by volume.

GWF Hanford will only fire the proposed emergency internal combustion engine on CARB certified diesel fuel which is certified to have a maximum sulfur content of 15 ppm and a maximum aromatic content of 35 percent by volume. Therefore, compliance with the requirements of this section is expected. The following condition will ensure continued compliance:

- 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]

Operating Requirements

Section 60.4209(a) states that the owner of operator of a diesel fired emergency internal combustion engine shall install a non-resettable hour meter prior to startup of the engine. The following condition will ensure continued 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 60.4209(a)]

Section 60.4211(a) requires that the owner/operator of each diesel fired emergency internal combustion engine must operate and maintain the engine and any installed control devices according to manufacturer's written instructions. Additionally, owners or operators may only change those settings that are permitted by the manufacturer. The following conditions will ensure continued compliance:

- 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)]

- During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [40 CFR 60.4211(a)]

Section 60.4211(e) allows each stationary emergency internal combustion engine may be operated up to 100 hours per year for maintenance and testing purposes. The following condition will ensure continued compliance:

- 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 100 hours per calendar year. [District Rule 4702, 40 CFR 60.4211(e) and 17 CCR 93115]

<u>Recordkeeping Requirements</u>

Section 60.4214(b) states that for engines manufactured on or after the dates in the following table that do not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. GWF Hanford will be required to maintain records of the emergency and non-emergency hours of operation in accordance with District Rule 4702 and 17 CCR 93115. Therefore, GWF Hanford will be in compliance with the requirements of this section. The following condition will ensure continued compliance:

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, emergency fire fighting, 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, 40 CFR 60.4214(b) and 17 CCR 93115]

Conclusion:

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

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

This rule incorporates NESHAP's from Part 61, Chapter I, Subchapter C, Title 40, CFR and the NESHAP's from Part 63, Chapter I, Subchapter C, Title 40, CFR; and applies to all sources of hazardous air pollution listed in 40 CFR Part 61 or 40 CFR Part 63.

The requirements of 40 CFR Part 63, Subpart ZZZZ (National Emission Standards for Hazardous Air Pollutants: Stationary Reciprocating Internal Combustion Engines) is the only applicable subpart for this facility:

C-4140-3 (emergency IC engine):

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.

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 engines will be in compliance with 40 CFR 60 Subpart IIII; therefore, the proposed engines are in compliance with Subpart ZZZZ requirements and no further discussion is required.

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).

C-4140-1 and '-2 (natural gas fired turbines):

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.

Proposed Rule 4101 Conditions:

- 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]

- 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]

C-4140-3 (emergency IC engine):

The following condition will ensure compliance for the IC engine:

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

Rule 4102 Nuisance

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

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

California Health & Safety Code 41700 (Health Risk Analysis)

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

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

Screen HRA Summary				
	Acute Hazard Index	Chronic Hazard Index	70 yr Cancer Risk	T-BACT Required?
C-4140-1-5 (Turbine #1) C-4140-2-5 (Turbine #2)	N/A[(1)]	N/A[(1)]	N/A[(1)]	No
C-4140-3-0 (IC Engine)	N/A	N/A	N/A	No

Discussion of Toxics Best Available Control Technology (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 for either of the natural gas fired turbines or the new diesel fired emergency IC powering a fire water pump. TBACT is not triggered.

Rule 4201 Particulate Matter Concentration

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

<u>*C-4140-1 and '-2 (natural gas fired turbines):*</u>

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

PM_{10} emission rate = 2.20 lb/hr. Assuming 100% of PM is PM_{10}
H_2O = 10.39% (worst case provided by turbine vendor)
Exhaust Gas Flow, acfm (wet) = 605,510
Exhaust Gas Flow, dscfm = 605,510 ∗ [(100 – 10.39)/100] = 542,598

PM Conc. (gr/scf)=[(2.20 lb/hr) ∗ (7,000 gr/lb)] ÷ [(542,598 ft^3/min) ∗ (60 min/hr)]
PM Conc. = 0.00047 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.

[(1)] Based on the previous risk management reviews (RMR's) performed for these natural gas fired turbines during previous permitting actions, there is not an increase in the amount of fuel used by units as a part of this project. Therefore, there is not an increase in risk associated with the proposed changes and no additional analysis is required.

Proposed Rule 4201 Condition:

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

C-4140-3 (emergency IC 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:

$$0.078\ \frac{g-PM_{10}}{bhp-hr}\times\frac{1g-PM}{0.96g-PM_{10}}\times\frac{1\,bhp-hr}{2{,}542.5\,Btu}\times\frac{10^6\,Btu}{9{,}051\,dscf}\times\frac{0.35\,Btu_{out}}{1\,Btu_{in}}\times\frac{15.43\,grain}{g}=0.0191\ \frac{grain-PM}{dscf}$$

Since 0.0191 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Proposed Rule 4201 Condition:

- 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 the two CTG's or diesel-fired emergency internal combustion engine within this project and no further discussion is required.

Rule 4301 ***Fuel Burning Equipment***

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

C-4140-1 and '-2 (natural gas fired turbines):

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

Rule 4702 Internal Combustion Engines – Phase 2

C-4140-3 (emergency IC engine):

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 4.3, 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, the emergency IC engine involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

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 ATC to ensure compliance:

- 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 100 hours per calendar year. [District Rule 4702, 40 CFR 60.4211(e) and 17 CCR 93115]

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, emergency fire fighting, 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, 40 CFR 60.4214(b) 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 conditions will ensure compliance:

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

- An emergency situation is an unscheduled event caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

Rule 4703 Stationary Gas Turbines

C-4140-1 and '-2 (natural gas fired turbines):

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. GWF Hanford is made up of two 47.5 MW stationary 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 specifies the Tier 1 NO_X compliance limits. As discussed below, GWF Hanford is proposing to operate these stationary gas turbines in compliance with the Tier 2 NO_X emission limits specified in section 5.1.2. The Tier 2 NO_X emission limits are more stringent than the Tier 1 NO_X emissions limits. Therefore, compliance with the Tier 1 NO_X emission limits will be demonstrated with compliance of the Tier 2 NO_X emission limits and no further discussion is required.

Section 5.1.2 specifies the Tier 2 NO_X compliance limits for all stationary gas turbines.

Simple Cycle Mode:

Table 5-2 of this rule limits the NO_X emissions from simple cycle, stationary gas turbine systems rated at greater than 10 MW and allowed to operate more than 876 hours per year to 5 ppmv @ 15% O_2 (Standard Compliance Option) and 3 ppmv @ 15% O_2 (Enhanced Compliance Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed simple cycle turbines will be limited to 2.5 ppmv @ 15% O_2 (based on a 1-hour average). Therefore, GWF Hanford will be in compliance with the enhanced compliance option and compliance with this section is expected. The following condition will ensure continued compliance with the requirements of this section:

- When operating in simple cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 4.24 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

Combined Cycle Mode:

Table 5-2 of this rule limits the NO_X emissions from combined cycle, stationary gas turbine systems rated at greater than 10 MW to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed combined cycle turbines will be limited to 2.0 ppmv @ 15% O_2 (based on a 1-hour average). Therefore, GWF Hanford will be in compliance with the Tier 2 enhanced NO_X compliance option and compliance with this section is expected. The following condition will ensure continued compliance with the requirements of this section:

- When operating in combined cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 3.40 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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 specifies the Tier 3 NO_X compliance limits for stationary gas turbines rated at less than 10 MW and stationary gas turbines that are allows to operate no more than 877 hours per year. GWF Hanford will be allowed to operate these turbines for up to 8,500 hours per year. Therefore, the requirements of Section 5.1.3 are not applicable and no further discussion is required.

<u>Section 5.2 – CO Emission Requirements:</u>

Per Table 5-4 of section 5.2, the CO emissions concentration from the proposed turbines must be less than 200 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 Hanford is proposing to operate these turbines, in either operating mode, with a CO emission concentration limit of 3 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 ensure continued compliance with the requirements of this section:

- When operating in simple cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 4.24 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

- When operating in combined cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 3.40 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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 5.3 – Transitional Operation Periods:

This section states that the emission limit requirements of Sections 5.1 or 5.2 shall not apply during any transitional operation period (bypass transition period, primary re-ignition period, reduced load period, startup or shutdown) provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, except as provided in section 5.3.3 below.
- For each bypass transition period, the requirements specified in Section 3.2 shall be met.
- For each primary re-ignition period, the requirements specified in Section 3.20 shall be met.
- Each reduced load period shall not exceed one hour.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during each transitional operation 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 Hanford is only 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 two hours. The SCR system and oxidation catalyst will be in operation during startup and shutdown in order to minimize emissions insofar as technologically feasible during startups and shutdowns. Therefore, the proposed turbines will be operating in compliance with the startup and shutdown requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

Simple Cycle Mode:

- When operating in simple cycle mode, during start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 7.70 lb/event; CO – 7.70 lb/event; VOC (as methane) – 0.70 lb/event; PM_{10} – 0.13 lb/event; or SO_X (as SO_2) – 0.054 lb/event. [District Rules 2201 and 4703]

- When operating in simple cycle mode, during shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 7.70 lb/event; CO – 7.70 lb/event; VOC (as methane) – 0.70 lb/event; PM_{10} – 0.20 lb/event; or SO_X (as SO_2) – 0.054 lb/event. [District Rules 2201 and 4703]

Combined Cycle Mode:

- When operating in combined cycle mode, during start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 6.10 lb/event; CO – 3.00 lb/event; VOC (as methane) – 0.50 lb/event; PM_{10} – 2.20 lb/event; or SO_X (as SO_2) – 0.31 lb/event. [District Rules 2201 and 4703]

- When operating in combined cycle mode, during shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 2.08 lb/event; CO – 1.00 lb/event; VOC (as methane) – 0.20 lb/event; PM_{10} – 0.73 lb/event; or SO_X (as SO_2) – 0.10 lb/event. [District Rules 2201 and 4703]

Either Operating Mode:

- A simple cycle startup period shall be defined as the period of time during which a unit is brought from a shutdown status until the unit meets the steady state simple cycle lb/hr and ppmvd emission limits specified within this permit. A combined cycle startup period shall be defined as the period of time beginning with the gas turbine operating in simple cycle mode and the initial start sequence of the once-through heat recovery steam generator until the unit meets the steady state combined cycle lb/hr and ppmvd emission limits specified within this permit. A combined cycle shutdown shall be defined as the period of time during which the initial shutdown sequence is given for the once through heat recovery steam generator until the unit meets the steady state simple cycle lb/hr and ppmvd emission limits specified within this permit. A simple cycle shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup or shutdown shall not exceed 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 Rules 2201 and 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, CO and oxygen content of each turbine's 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 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 and/or shutdown conditions, CEMS results during startup and shutdown events shall be replaced with startup and/or shutdown emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

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

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbines at this facility were installed in 2002. 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 Hanford 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:

- All records shall be maintained and retained on-site for a period of at least five years and shall be made available for District inspection upon request. [District Rules 1070, 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 Hanford 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:

- When operating in simple cycle mode and when operating in combined cycle more, the permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit when no continuous emission monitoring data for NO_X is available or when continuous emission monitoring system is not operating 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 Hanford will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, calculated NO_X and CO mass emission rates (lb/hr and lb/twelve month rolling period), and VOC, PM_{10} and SO_X mass emission rates (lb/twelve month rolling period). [District Rules 2201 and 4703]

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

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

Sections 6.2.9 and 6.2.12 specify recordkeeping requirements for units subject to Section 5.1.3.3 and Table 5-3 of this rule. As stated above, these turbines are not subject to the requirements of Section 5.1.3 or table 5-3 of this rule. Therefore, the recordkeeping requirements of these sections are not applicable and no further discussion is required.

Section 6.2.10 specifies recordkeeping requirements for units subject to Section 6.5.2, Exempt and Emergency Standby Units. As discussed above, the proposed turbines are subject to the requirements of this rule and are not going to be operated as Emergency Standby Units. Therefore, the recordkeeping requirements of this section are not applicable and no further discussion is required.

Section 6.2.11 specifies recordkeeping requirements for each bypass transition period and each re-ignition period. GWF Hanford has not proposed to incorporate any requirements in to their conditions pertaining to allowing bypass transition periods or re-ignition periods. Therefore, the requirements of this section are not applicable and 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 Hanford are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, each of the proposed turbines will be allowed to operate up to 8,500 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 specifies source testing requirements for units that are equipped with intermittently operated auxiliary burners. GWF is not proposing to operate any of these turbines with auxiliary burners. Therefore, the requirements of this section are not applicable and no further discussion is required.

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

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.

- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

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

- The following test methods shall be used: NO_X - EPA Method 7E, 20, or ARB Method 100 (ppmv basis), or EPA Method 19 (lb/MMBtu basis); CO - EPA Method 10, 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM_{10} - EPA Method 5 and 202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, 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 40 CFR 60.4400(a)(2), (3), and (b)]

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:

C-4140-1 and '-2 (natural gas fired turbines):

The sulfur content of the natural gas fuel burned in these turbines will be limited to 0.24 gr/100 dscf. Converting the sulfur content over to a lb-SO_X/MMBtu emission factor can be done as follows:

SO_X EF (lb/MMBtu) = 0.24 (gr-S/100 dscf) x lb/7,000 gr x dscf/1,020 Btu x 10^6 MMBtu/Btu x 64 lb SO_2/32 lb S

SO_X EF = 0.000672 lb/MMBtu

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)
- $n = \frac{0.000672\ lb}{MMBtu} \times \frac{1\ (lb - mol)}{64\ lb} = 0.0000105\ (lb - mol)$
- $R = \frac{0.7302\ ft^3 \cdot atm}{(lb - mol)\,°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

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

$$V = \frac{0.0000105\ (lb - mol) \cdot \frac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.0038\ ft^3$$

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

$$= \frac{0.0038}{8{,}578} = 0.000000443 = 0.4\ ppmv = 0.000043\%\ by\ volume$$

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

District Rule 8011 General Requirements
District Rule 8021 Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities
District Rule 8031 Bulk Materials
District Rule 8041 Carryout And Trackout
District Rule 8051 Open Areas
District Rule 8061 Paved And Unpaved Roads
District Rule 8071 Unpaved Vehicle/Equipment Traffic Areas
District Rule 8081 Agricultural Sources

The conversion of this existing simple cycle power plant to a combined cycle power plant 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:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

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)

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

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

Title 13 CCR, Section 2423 lists a diesel particulate emission standard of 0.15 g/bhp-hr (equivalent to 0.20 g/kW-hr) for engines with maximum power ratings ranging between of 301.7 - 603.4 bhp (equivalent to 225 - 450 kW). The PM standards given in Title 13 CCR, Section 2423 are less stringent than the PM standards given in Title 17 CCR, Section 93115 (ATCM), thus the ATCM standards are the required standards and will be discussed in the following section.

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

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

Requirements of Title 13 CCR, Section 2423					
Source	Maximum Rated Power	Model Year	NO_X + VOC	CO	PM
Title 13 CCR, §2423	301.7 – 603.4 bhp (225 - 450 kW)	2001-2005, extended to 2008 (Tier 2)	4.8 g/bhp-hr (6.4 g/kW-hr)	2.6 g/bhp-hr (3.5 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Title 13 CCR, §2423	301.7 – 603.4 bhp (225 - 450 kW)	2006 and later, extended to 2009 (Tier 3)	3.0 g/bhp-hr (4.0 g/kW-hr)	2.6 g/bhp-hr (3.5 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Cummins, model CFP15E-F10	460 bhp	2009	2.747 g/bhp-hr (3.684 g/kW-hr)	0.671 g/bhp-hr (0.90 g/kW-hr)	0.078 g/bhp-hr (0.105 g/kW-hr)
Meets Standard?			Yes	Yes	Yes

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

<u>Emergency Operating Requirements:</u>

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.

<u>Fuel and Fuel Additive Requirements:</u>

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 will 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," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

   I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
   II. Amount of fuel purchased;
   III. Date when the fuel was purchased;
   IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
   V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions will ensure continued compliance:

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, emergency fire fighting, 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, 40 CFR 60.4214(b) 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 New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or

2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and

3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions will ensure compliance:

- Emissions from this IC engine shall not exceed 0.078 g-PM_{10}/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. 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 100 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

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 and no further discussion is required.

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 Final Determination of Compliance for the facility subject to the conditions presented in Attachment A.

X. BILLING INFORMATION:

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-4140-1-5	3020-08B-G	60,000 kW	$9,458
C-4140-2-5	3020-08B-G	60,000 kW	$9,458
C-4140-3-0	3020-10-D	460 bhp IC engine	$443

ATTACHMENT A

FDOC CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-4140-1-5:
MODIFICATION OF 47.5 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION AND AN OXIDATION CATALYST: CONVERT THE EXISTING POWER GENERATING SYSTEM TO A SIMPLE CYCLE OR COMBINED CYCLE CONFIGURATION BY (1) REMOVING THE EXISTING OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION SYSTEM AND 85' EXHAUST STACK; (2) INSTALLING A NEW ONCE THROUGH HEAT RECOVERY STEAM GENERATOR; (3) INSTALLING A NEW OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION SYSTEM AND 91.5' TALL EXHAUST STACK; AND (4) INSTALLING A 25 MW NOMINALLY RATED CONDENSING STEAM TURBINE GENERATOR AND ITS ASSOCIATED LUBE OIL COOLER (SHARED WITH C-4140-2)

1. 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 Rule 2201]

2. 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]

3. 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, 5.8.8]

4. The permittee shall not begin actual onsite construction of the equipment authorized by this Determination of Compliance until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

5. Authority to Construct (ATC) C-603-1-8 shall be implemented concurrently, or prior to the modification and startup of the equipment authorized by this Determination of Compliance. [District Rule 2201]

6. District facilities C-603 and C-4140 are the same stationary source for District permitting purposes. [District Rule 2201]

7. The owner/operator of GWF Hanford shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #8 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, conditions #19 through #102 shall apply after the commissioning period has ended. [District Rule 2201]

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

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing and is available for commercial operation. [District Rule 2201]

10. 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]

11. 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 the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

12. Coincident with the end of the commission period and the steady-state operation of the SCR system and the oxidation catalyst, NO_X and CO emissions from this unit shall comply with the steady state emission limits specified in condition #28 or #32. [District Rule 2201]

13. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, 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 the activity. The activities described shall include, but not be limited to, the tuning of the combustors, the installation and operation of the SCR systems and the oxidation catalyst, the installation, calibration, and testing of the NO_X and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

14. Emission rates from this CTG, during the commissioning period, shall not exceed any of the following limits: NO_X (as NO2) – 52.00 lb/hr; CO – 40.50 lb/hr; VOC (as methane) – 1.20 lb/hr; PM_{10} – 2.20 lb/hr; or SO_X (as SO2) – 0.31 lb/hr. [District Rule 2201]

15. During the initial commissioning activities, the permittee shall demonstrate compliance with the NO_X emission limit specified in condition #14 through the use of a properly operated and maintained continuous emissions 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 permittee shall demonstrate compliance with the NO_X and CO emission limits specified in condition #14 through the use of a properly operated and maintained continuous emission monitors and recorders as specified in conditions #55 and #57. 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]

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

17. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 430 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 430 firing hours without abatement shall expire. [District Rule 2201]

18. The total mass emissions of NO_X, CO, VOC, PM_{10}, and SO_X that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #41. [District Rule 2201]

19. 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 permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

20. Permittee 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]

21. When operating in simple cycle mode and when operating in combined cycle mode, the permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit when no continuous emission monitoring data for NO_X is available or when continuous emission monitoring system is not operating properly. [District Rule 4703]

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

24. 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]

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

26. 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]

27. This CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 0.24 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

28. When operating in simple cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 4.24 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

29. When operating in simple cycle mode, during start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 7.70 lb/event; CO – 7.70 lb/event; VOC (as methane) – 0.70 lb/event; PM_{10} – 0.13 lb/event; or SO_X (as SO_2) – 0.054 lb/event. [District Rules 2201 and 4703]

30. When operating in simple cycle mode, during shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 7.70 lb/event; CO – 7.70 lb/event; VOC (as methane) – 0.70 lb/event; PM_{10} – 0.20 lb/event; or SO_X (as SO_2) – 0.054 lb/event. [District Rules 2201 and 4703]

31. When operating in simple cycle mode, the ammonia (NH_3) emissions shall not exceed either of the following limits: 6.20 lb/hr or 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

32. When operating in combined cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 3.40 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

33. When operating in combined cycle mode, during start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 6.10 lb/event; CO – 3.00 lb/event; VOC (as methane) – 0.50 lb/event; PM_{10} – 2.20 lb/event; or SO_X (as SO_2) – 0.31 lb/event. [District Rules 2201 and 4703]

34. When operating in combined cycle mode, during shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 2.08 lb/event; CO – 1.00 lb/event; VOC (as methane) – 0.20 lb/event; PM_{10} – 0.73 lb/event; or SO_X (as SO_2) – 0.10 lb/event. [District Rules 2201 and 4703]

35. When operating in combined cycle mode, the ammonia (NH_3) emissions shall not exceed either of the following limits: 3.10 lb/hr or 5 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

36. A simple cycle startup period shall be defined as the period of time during which a unit is brought from a shutdown status until the unit meets the steady state simple cycle lb/hr and ppmvd emission limits specified within this permit. A combined cycle startup period shall be defined as the period of time beginning with the gas turbine operating in simple cycle mode and the initial start sequence of the once through heat recovery steam generator until the unit meets the steady state combined cycle lb/hr and ppmvd emission limits specified within this permit. A combined cycle shutdown shall be defined as the period of time during which the initial shutdown sequence is given for the once through heat recovery steam generator until the unit meets the steady state simple cycle lb/hr and ppmvd emission limits specified within this permit. A simple cycle shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

37. The duration of each startup or shut down period shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

38. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rules 2201 and 4703]

39. 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]

40. Maximum daily emissions from the CTG shall not exceed any of the following limits: NO_X (as NO_2) – 129.7 lb/day; CO – 103.1 lb/day; VOC – 30.8 lb/day; PM_{10} – 52.1 lb/day; or SO_X (as SO_2) – 7.5 lb/day. [District Rule 2201]

41. Annual emissions from this CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 35,998 lb/year; CO – 20,705 lb/year; VOC – 4,683 lb/year; PM_{10} – 18,659 lb/year; or SO_X (as SO_2) – 2,649 lb/year. Compliance with the annual NO_X and CO emission limits shall be demonstrated using CEM data and the annual VOC, PM_{10} and SO_X 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. 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 permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

45. When operating in simple cycle mode and when operating in combined cycle mode, source testing to measure startup and shutdown NO_X, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-4140-1 or C-4140-2) within 60 days after the end of the commissioning period. [District Rules 1081 and 2201]

46. Source testing to measure startup and shutdown NO_X, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-4140-1 or C-4140-2) at least once every seven years. CEM relative accuracy 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 or shutdown emission limits, then source testing to measure startup and shutdown NO_X and CO mass emission rates shall be conducted at least once every 12 months. If an annual startup and shutdown NO_X and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NO_X and CO testing frequency shall return to the once every seven years schedule. [District Rules 1081 and 2201]

47. When operating in simple cycle mode, initial source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

48. When operating in combined cycle mode, initial source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

49. Source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

50. Testing to demonstrate compliance with the fuel sulfur content limit of 0.24 grains of sulfur compounds (as S) per 100 dry scf of natural gas 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 the 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. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. The following test methods shall be used: NO_X - EPA Method 7E, 20, or ARB Method 100 (ppmv basis), or EPA Method 19 (lb/MMBtu basis); CO - EPA Method 10, 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM_{10} - EPA Method 5 and 202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, 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 40 CFR 60.4400(a)(2), (3), and (b)]

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

53. The 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]

54. 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 and 40 CFR 60.4375(b)]

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

56. 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]

57. 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 and/or shutdown conditions, CEMS results during startup and shutdown events shall be replaced with startup and/or shutdown 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)]

58. The owner/operator shall develop and keep on site a quality assurance plan for the NO_X CEMS. [40 CFR 60.4345(e)]

59. 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)]

60. 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 (PS 2, 3 and 4), 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)]

61. 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]

62. 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 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. 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(a)]

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

64. When operating in simple cycle mode, excess NO_X emissions shall be defined as any operating hour in which the 1-hour rolling average NO_X concentration exceeds an applicable emissions limit. When operating in combined cycle mode, excess NO_X emissions shall be defined as any 30 day operating period in which the 30 day rolling average NO_X concentration exceeds an applicable emissions limit. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O_2 (or both). [40 CFR 60.4350(g), 40 CFR 60.4350(h) and 40 CFR 60.4380(b)(1)]

65. For the purpose of determining excess NO_X emission, 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 NO_X emission rate in units of ppm, using the appropriate equation from Method 19 of 40 CFR 60, Appendix A. For any hour in which the hourly O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations. [40 CFR 60.4350(b) and 60.4350(f)]

66. Excess SO_X 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 SO_X begins when a sample is not taken by its due date. A period of monitor downtime for SO_X also begins on the date and hour of a required sample, if invalid results are obtained. A period of SO_X monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)]

67. 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]

68. 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]

69. 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]

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. 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]

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

73. 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]

74. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

75. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, calculated NO_X and CO mass emission rates (lb/hr and lb/twelve month rolling period), and VOC, PM_{10} and SO_X mass emission rates (lb/twelve month rolling period). [District Rules 2201 and 4703]

76. All records shall be maintained and retained on-site for a period of at least five years and shall be made available for District inspection upon request. [District Rules 1070, 2201 and 4703]

77. 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 superseding Acid Rain permit issued by the permitting authority; and (ii) Have an Acid Rain permit. [40 CFR 72]

78. 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]

79. 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]

80. 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]

81. 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]

82. 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 and 40 CFR 75]

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

84. 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]

85. 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]

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

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

88. 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]

89. 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]

90. 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 superseded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72]

91. 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 75]

92. 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]

93. 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]

94. 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]

95. 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]

96. 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]

97. 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]

98. 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 Rules 8011 and 8071]

99. 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 Rules 8011 and 8071]

100. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

101. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

102. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-4140-2-5:
MODIFICATION OF 47.5 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION AND AN OXIDATION CATALYST: CONVERT THE EXISTING POWER GENERATING SYSTEM TO A SIMPLE CYCLE OR COMBINED CYCLE CONFIGURATION BY (1) REMOVING THE EXISTING OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION SYSTEM AND 85' EXHAUST STACK; (2) INSTALLING A NEW ONCE THROUGH HEAT RECOVERY STEAM GENERATOR; (3) INSTALLING A NEW OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION SYSTEM AND 91.5' TALL EXHAUST STACK; AND (4) INSTALLING A 25 MW NOMINALLY RATED CONDENSING STEAM TURBINE GENERATOR AND ITS ASSOCIATED LUBE OIL COOLER (SHARED WITH C-4140-1)

1. 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 Rule 2201]

2. 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]

3. 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, 5.8.8]

4. The permittee shall not begin actual onsite construction of the equipment authorized by this Determination of Compliance until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

5. Authority to Construct (ATC) C-603-1-8 shall be implemented concurrently, or prior to the modification and startup of the equipment authorized by this Determination of Compliance. [District Rule 2201]

6. District facilities C-603 and C-4140 are the same stationary source for District permitting purposes. [District Rule 2201]

7. The owner/operator of GWF Hanford shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. Conditions #8 through #18 shall apply only during the commissioning period as defined below. Unless otherwise indicated, conditions #19 through #102 shall apply after the commissioning period has ended. [District Rule 2201]

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

9. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing and is available for commercial operation. [District Rule 2201]

10. 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]

11. 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 the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

12. Coincident with the end of the commission period and the steady-state operation of the SCR system and the oxidation catalyst, NO_X and CO emissions from this unit shall comply with the steady state emission limits specified in condition #28 or #32. [District Rule 2201]

13. The permittee shall submit a plan to the District at least four weeks prior to the first firing of this unit, 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 the activity. The activities described shall include, but not be limited to, the tuning of the combustors, the installation and operation of the SCR systems and the oxidation catalyst, the installation, calibration, and testing of the NO_X and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

14. Emission rates from this CTG, during the commissioning period, shall not exceed any of the following limits: NO_X (as NO2) – 52.00 lb/hr; CO – 40.50 lb/hr; VOC (as methane) – 1.20 lb/hr; PM_{10} – 2.20 lb/hr; or SO_X (as SO2) – 0.31 lb/hr. [District Rule 2201]

15. During the initial commissioning activities, the permittee shall demonstrate compliance with the NO_X emission limit specified in condition #14 through the use of a properly operated and maintained continuous emissions 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 permittee shall demonstrate compliance with the NO_X and CO emission limits specified in condition #14 through the use of a properly operated and maintained continuous emission monitors and recorders as specified in conditions #55 and #57. 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]

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

17. The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 430 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 430 firing hours without abatement shall expire. [District Rule 2201]

18. The total mass emissions of NO_X, CO, VOC, PM_{10}, and SO_X that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #41. [District Rule 2201]

19. 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 permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

20. Permittee 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]

21. When operating in simple cycle mode and when operating in combined cycle mode, the permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit when no continuous emission monitoring data for NO_X is available or when continuous emission monitoring system is not operating properly. [District Rule 4703]

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

24. 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]

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

26. 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]

27. This CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 0.24 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

28. When operating in simple cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 4.24 lb/hr and 2.5 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

29. When operating in simple cycle mode, during start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 7.70 lb/event; CO – 7.70 lb/event; VOC (as methane) – 0.70 lb/event; PM_{10} – 0.13 lb/event; or SO_X (as SO_2) – 0.054 lb/event. [District Rules 2201 and 4703]

30. When operating in simple cycle mode, during shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 7.70 lb/event; CO – 7.70 lb/event; VOC (as methane) – 0.70 lb/event; PM_{10} – 0.20 lb/event; or SO_X (as SO_2) – 0.054 lb/event. [District Rules 2201 and 4703]

31. When operating in simple cycle mode, the ammonia (NH_3) emissions shall not exceed either of the following limits: 6.20 lb/hr or 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

32. When operating in combined cycle mode, the steady state emission rates from this CTG, except during startup and shutdown periods, shall not exceed any of the following limits: NO_X (as NO_2) – 3.40 lb/hr and 2.0 ppmvd @ 15% O_2; CO – 3.10 lb/hr and 3.0 ppmvd @ 15% O_2; VOC (as methane) – 1.20 lb/hr and 2.0 ppmvd @ 15% O_2; PM_{10} – 2.20 lb/hr; or SO_X (as SO_2) – 0.31 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)]

33. When operating in combined cycle mode, during start-up, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 6.10 lb/event; CO – 3.00 lb/event; VOC (as methane) – 0.50 lb/event; PM_{10} – 2.20 lb/event; or SO_X (as SO_2) – 0.31 lb/event. [District Rules 2201 and 4703]

34. When operating in combined cycle mode, during shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 2.08 lb/event; CO – 1.00 lb/event; VOC (as methane) – 0.20 lb/event; PM_{10} – 0.73 lb/event; or SO_X (as SO_2) – 0.10 lb/event. [District Rules 2201 and 4703]

35. When operating in combined cycle mode, the ammonia (NH_3) emissions shall not exceed either of the following limits: 3.10 lb/hr or 5 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rules 2201 and 4102]

36. A simple cycle startup period shall be defined as the period of time during which a unit is brought from a shutdown status until the unit meets the steady state simple cycle lb/hr and ppmvd emission limits specified within this permit. A combined cycle startup period shall be defined as the period of time beginning with the gas turbine operating in simple cycle mode and the initial start sequence of the once through heat recovery steam generator until the unit meets the steady state combined cycle lb/hr and ppmvd emission limits specified within this permit. A combined cycle shutdown shall be defined as the period of time during which the initial shutdown sequence is given for the once through heat recovery steam generator until the unit meets the steady state simple cycle lb/hr and ppmvd emission limits specified within this permit. A simple cycle shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

37. The duration of each startup or shut down period shall not exceed two hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

38. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rules 2201 and 4703]

39. 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]

40. Maximum daily emissions from the CTG shall not exceed any of the following limits: NO_X (as NO_2) – 129.7 lb/day; CO – 103.1 lb/day; VOC – 30.8 lb/day; PM_{10} – 52.1 lb/day; or SO_X (as SO_2) – 7.5 lb/day. [District Rule 2201]

41. Annual emissions from this CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 35,998 lb/year; CO – 20,705 lb/year; VOC – 4,683 lb/year; PM_{10} – 18,659 lb/year; or SO_X (as SO_2) – 2,649 lb/year. Compliance with the annual NO_X and CO emission limits shall be demonstrated using CEM data and the annual VOC, PM_{10} and SO_X 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. 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 permittee shall submit a detailed calculation protocol for District approval at least 60 days prior to commencement of operation; 3.) Alternatively, the permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the permittee shall submit a monitoring plan for District approval at least 60 days prior to commencement of operation. [District Rules 2201 and 4102]

45. When operating in simple cycle mode and when operating in combined cycle mode, source testing to measure startup and shutdown NO_X, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-4140-1 or C-4140-2) within 60 days after the end of the commissioning period. [District Rules 1081 and 2201]

46. Source testing to measure startup and shutdown NO_X, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-4140-1 or C-4140-2) at least once every seven years. CEM relative accuracy 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 or shutdown emission limits, then source testing to measure startup and shutdown NO_X and CO mass emission rates shall be conducted at least once every 12 months. If an annual startup and shutdown NO_X and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NO_X and CO testing frequency shall return to the once every seven years schedule. [District Rules 1081 and 2201]

47. When operating in simple cycle mode, initial source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

48. When operating in combined cycle mode, initial source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of the commissioning period. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

49. Source testing to determine compliance with the steady state NO_X, CO, VOC and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

50. Testing to demonstrate compliance with the fuel sulfur content limit of 0.24 grains of sulfur compounds (as S) per 100 dry scf of natural gas 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 the 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. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. The following test methods shall be used: NO_X - EPA Method 7E, 20, or ARB Method 100 (ppmv basis), or EPA Method 19 (lb/MMBtu basis); CO - EPA Method 10, 10B or ARB Method 100; VOC - EPA Method 18 or 25; PM_{10} - EPA Method 5 and 202 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, 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 40 CFR 60.4400(a)(2), (3), and (b)]

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

53. The 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]

54. 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 and 40 CFR 60.4375(b)]

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

56. 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]

57. 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 and/or shutdown conditions, CEMS results during startup and shutdown events shall be replaced with startup and/or shutdown 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)]

58. The owner/operator shall develop and keep on site a quality assurance plan for the NO_X CEMS. [40 CFR 60.4345(e)]

59. 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)]

60. 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 (PS 2, 3 and 4), 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)]

61. 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]

62. 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 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. 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(a)]

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

64. When operating in simple cycle mode, excess NO_X emissions shall be defined as any operating hour in which the 1-hour rolling average NO_X concentration exceeds an applicable emissions limit. When operating in combined cycle mode, excess NO_X emissions shall be defined as any 30 day operating period in which the 30 day rolling average NO_X concentration exceeds an applicable emissions limit. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O_2 (or both). [40 CFR 60.4350(g), 40 CFR 60.4350(h) and 40 CFR 60.4380(b)(1)]

65. For the purpose of determining excess NO_X emission, 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 NO_X emission rate in units of ppm, using the appropriate equation from Method 19 of 40 CFR 60, Appendix A. For any hour in which the hourly O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations. [40 CFR 60.4350(b) and 60.4350(f)]

66. Excess SO_X 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 SO_X begins when a sample is not taken by its due date. A period of monitor downtime for SO_X also begins on the date and hour of a required sample, if invalid results are obtained. A period of SO_X monitoring downtime ends on the date and hour of the next valid sample. [40 CFR 60.4385(a) and (c)]

67. 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]

68. 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]

69. 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]

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. 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]

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

73. 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]

74. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 1080, 2201 and 4703 and 40 CFR 60.8(d)]

75. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, calculated NO_X and CO mass emission rates (lb/hr and lb/twelve month rolling period), and VOC, PM_{10} and SO_X mass emission rates (lb/twelve month rolling period). [District Rules 2201 and 4703]

76. All records shall be maintained and retained on-site for a period of at least five years and shall be made available for District inspection upon request. [District Rules 1070, 2201 and 4703]

77. 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 superseding Acid Rain permit issued by the permitting authority; and (ii) Have an Acid Rain permit. [40 CFR 72]

78. 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]

79. 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]

80. 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]

81. 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]

82. 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 and 40 CFR 75]

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

84. 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]

85. 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]

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

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

88. 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]

89. 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]

90. 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 superseded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72]

91. 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 75]

92. 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]

93. 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]

94. 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]

95. 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]

96. 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]

97. 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]

98. 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 Rules 8011 and 8071]

99. 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 Rules 8011 and 8071]

100. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rules 8011 and 8071]

101. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

102. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-4140-3-0:
460 BHP CUMMINS MODEL CFP15E-F10 TIER 3 CERTIFIED DIESEL-FIRED EMERGENCY INTERNAL COMBUSTION (IC) ENGINE POWERING A FIREWATER PUMP

1. 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 Rule 2201]

2. 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]

3. 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, 5.8.8]

4. The permittee shall not begin actual onsite construction of the equipment authorized by this Determination of Compliance until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

5. Authority to Construct (ATC) C-603-1-8 shall be implemented concurrently, or prior to the modification and startup of the equipment authorized by this Determination of Compliance. [District Rule 2201]

6. District facilities C-603 and C-4140 are the same stationary source for District permitting purposes. [District Rule 2201]

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

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

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

10. Emissions from this IC engine shall not exceed any of the following limits: 2.66 g-NO_X/bhp-hr, 0.671 g-CO/bhp-hr, or 0.086 g-VOC/bhp-hr. [District Rule 2201, 40 CFR 60.4205(c), 13 CCR 2423 and 17 CCR 93115]

11. Emissions from this IC engine shall not exceed 0.078 g-PM_{10}/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102, 40 CFR 60.4205(c), 13 CCR 2423 and 17 CCR 93115]

12. 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]

13. 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)]

14. This engine shall be equipped with either a positive crankcase ventilation (PCV) system which 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]

15. 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]

16. 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)]

17. During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [40 CFR 60.4211(a)]

18. 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 100 hours per calendar year. [District Rule 4702, 40 CFR 60.4211(e) and 17 CCR 93115]

19. An emergency situation is an unscheduled event caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

20. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, emergency fire fighting, 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, 40 CFR 60.4214(b) and 17 CCR 93115]

21. 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

Existing Permits to Operate C-4140-0-0, '-1-3 and '-2-3

San Joaquin Valley
Air Pollution Control District

FACILITY: C-4140-0-0 **EXPIRATION DATE:** 04/30/2008

FACILITY-WIDE REQUIREMENTS

1. The owner or 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; County Rules 110 (Fresno, Stanislaus, San Joaquin); 109 (Merced); 113 (Madera); and 111 (Kern, Tulare, Kings)] Federally Enforceable Through Title V Permit
2. 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; County Rules 110 (Fresno, Stanislaus, San Joaquin); 109 (Merced); 113 (Madera); and 111 (Kern, Tulare, Kings)] Federally Enforceable Through Title V Permit
3. The owner or operator of any stationary source operation that emits more than 25 tons per year of nitrogen oxides or reactive organic compounds, shall provide the District annually with a written statement in such form and at such time as the District prescribes, showing actual emissions of nitrogen oxides and reactive organic compounds from that source. [District Rule 1160, 5.0] Federally Enforceable Through Title V Permit
4. 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 or the use of which may eliminate, reduce, or control the issuance of air contaminants, shall first obtain an Authority to Construct (ATC) from the District unless exempted by District Rule 2020 (3/21/02). [District Rule 2010, 3.0 and 4.0; and 2020] Federally Enforceable Through Title V Permit
5. The permittee must comply with all conditions of the permit including permit revisions originated by the District. All terms and conditions of a permit that are required pursuant to the Clean Air Act (CAA), including provisions to limit potential to emit, are enforceable by the EPA and Citizens under the CAA. Any permit noncompliance constitutes a violation of the CAA and the District Rules and Regulations, and is grounds for enforcement action, for permit termination, revocation, reopening and reissuance, or modification; or for denial of a permit renewal application. [District Rules 2070, 7.0; 2080; and 2520, 9.8.1 and 9.12.1] Federally Enforceable Through Title V Permit
6. A Permit to Operate or an Authority to Construct shall not be transferred unless a new application is filed with and approved by the District. [District Rule 2031] Federally Enforceable Through Title V Permit
7. Every application for a permit required under Rule 2010 (12/17/92) shall be filed in a manner and form prescribed by the District. [District Rule 2040] Federally Enforceable Through Title V Permit
8. The operator shall maintain records of required monitoring that include: 1) the date, place, and time of sampling or measurement; 2) the date(s) analyses were performed; 3) the company or entity that performed the analysis; 4) the analytical techniques or methods used; 5) the results of such analysis; and 6) the operating conditions at the time of sampling or measurement. [District Rule 2520, 9.4.1] Federally Enforceable Through Title V Permit
9. The operator shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, or report. Support information includes copies of all reports required by the permit and, for continuous monitoring instrumentation, all calibration and maintenance records and all original strip-chart recordings. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

FACILITY-WIDE REQUIREMENTS CONTINUE ON NEXT PAGE

10. The operator shall submit reports of any required monitoring at least every six months unless a different frequency is required by an applicable requirement. All instances of deviations from permit requirements must be clearly identified in such reports. [District Rule 2520, 9.5.1] Federally Enforceable Through Title V Permit
11. Deviations from permit conditions must be promptly reported, including deviations attributable to upset conditions, as defined in the permit. For the purpose of this condition, promptly means as soon as reasonably possible, but no later than 10 days after detection. The report shall include the probable cause of such deviations, and any corrective actions or preventive measures taken. All required reports must be certified by a responsible official consistent with section 10.0 of District Rule 2520 (6/21/01). [District Rules 2520, 9.5.2 and 1100, 7.0] Federally Enforceable Through Title V Permit
12. If for any reason a permit requirement or condition is being challenged for its constitutionality or validity by a court of competent jurisdiction, the outcome of such challenge shall not affect or invalidate the remainder of the conditions or requirements in that permit. [District Rule 2520, 9.7] Federally Enforceable Through Title V Permit
13. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. [District Rule 2520, 9.8.2] Federally Enforceable Through Title V Permit
14. The permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. [District Rule 2520, 9.8.3] Federally Enforceable Through Title V Permit
15. The permit does not convey any property rights of any sort, or any exclusive privilege. [District Rule 2520, 9.8.4] Federally Enforceable Through Title V Permit
16. The Permittee shall furnish to the District, within a reasonable time, any information that the District may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the District copies of records required to be kept by the permit or, for information claimed to be confidential, the permittee may furnish such records directly to EPA along with a claim of confidentiality. [District Rule 2520, 9.8.5] Federally Enforceable Through Title V Permit
17. The permittee shall pay annual permit fees and other applicable fees as prescribed in Regulation III of the District Rules and Regulations. [District Rule 2520, 9.9] Federally Enforceable Through Title V Permit
18. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to enter the permittee's premises where a permitted source is located or emissions related activity is conducted, or where records must be kept under condition of the permit. [District Rule 2520, 9.13.2.1] Federally Enforceable Through Title V Permit
19. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit. [District Rule 2520, 9.13.2.2] Federally Enforceable Through Title V Permit
20. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to inspect at reasonable times any facilities, equipment, practices, or operations regulated or required under the permit. [District Rule 2520, 9.13.2.3] Federally Enforceable Through Title V Permit
21. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or applicable requirements. [District Rule 2520, 9.13.2.4] Federally Enforceable Through Title V Permit
22. 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

FACILITY-WIDE REQUIREMENTS CONTINUE ON NEXT PAGE

23. No person shall manufacture, blend, repackage, supply, sell, solicit or apply any architectural coating with a VOC content in excess of the corresponding limit specified in the Table of Standards of District Rule 4601 (10/31/01) for use or sale within the District. [District Rule 4601, 5.1] Federally Enforceable Through Title V Permit

24. All VOC-containing materials for architectural coatings subject to Rule 4601 (10/31/01) shall be stored in closed containers when not in use. [District Rule 4601, 5.4] Federally Enforceable Through Title V Permit

25. The permittee shall comply with all the Labeling and Test Methods requirements outlined in Rule 4601 sections 6.1 and 6.3 (10/31/01). [District Rule 4601, 6.1 and 6.3] Federally Enforceable Through Title V Permit

26. With each report or document submitted under a permit requirement or a request for information by the District or EPA, the permittee shall include a certification of truth, accuracy, and completeness by a responsible official. [District Rule 2520, 9.13.1 and 10.0] Federally Enforceable Through Title V Permit

27. If the permittee performs maintenance on, or services, repairs, or disposes of appliances, the permittee shall comply with the standards for Recycling and Emissions Reduction pursuant to 40 CFR 82, Subpart F. [40 CFR 82 Subpart F] Federally Enforceable Through Title V Permit

28. If the permittee performs service on motor vehicles when this service involves the ozone-depleting refrigerant in the motor vehicle air conditioner (MVAC), the permittee shall comply with the standards for Servicing of Motor Vehicle Air Conditioners pursuant to all the applicable requirements as specified in 40 CFR 82, Subpart B. [40 CFR 82, Subpart B] Federally Enforceable Through Title V Permit

29. 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 (11/15/01) or Rule 8011 (11/15/01). [District Rule 8021 and 8011] Federally Enforceable Through Title V Permit

30. Outdoor handling, storage and transport of any bulk material which emits dust shall comply with the requirements of District Rule 8031, unless specifically exempted under Section 4.0 of Rule 8031 (11/15/01) or Rule 8011 (11/15/01). [District Rule 8031 and 8011] Federally Enforceable Through Title V Permit

31. 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 (11/15/01) or Rule 8011 (11/15/01). [District Rule 8041 and 8011] Federally Enforceable Through Title V Permit

32. 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 (11/15/01) or Rule 8011 (11/15/01). [District Rule 8051 and 8011] Federally Enforceable Through Title V Permit

33. 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 (11/15/01) or Rule 8011 (11/15/01). [District Rule 8061 and Rule 8011] Federally Enforceable Through Title V Permit

34. Any unpaved vehicle/equipment area that anticipates more than 75 vehicle trips per day shall comply with the requirements of Section 5.1.1 of District Rule 8071. Any unpaved vehicle/equipment area that anticipates more than 100 vehicle trips per day shall comply with the requirements of Section 5.1.2 of District Rule 8071. All sources shall comply with the requirements of Section 5.0 of District Rule 8071 unless specifically exempted under Section 4.0 of Rule 8071 (11/15/01) or Rule 8011 (11/15/01). [District Rule 8071 and Rule 8011] Federally Enforceable Through Title V Permit

35. Any owner or operator of a demolition or renovation activity, as defined in 40 CFR 61.141, shall comply with the applicable inspection, notification, removal, and disposal procedures for asbestos containing materials as specified in 40 CFR 61.145 (Standard for Demolition and Renovation). [40 CFR 61 Subpart M] Federally Enforceable Through Title V Permit

FACILITY-WIDE REQUIREMENTS CONTINUE ON NEXT PAGE

36. The permittee shall submit certifications of compliance with the terms and standards contained in Title V permits, including emission limits, standards and work practices, to the District and the EPA annually (or more frequently as specified in an applicable requirement or as specified by the District). The certification shall include the identification of each permit term or condition, the compliance status, whether compliance was continuous or intermittent, the methods used for determining the compliance status, and any other facts required by the District to determine the compliance status of the source. [District Rule 2520, 9.16] Federally Enforceable Through Title V Permit

37. The permittee shall submit an application for Title V permit renewal to the District at least six months, but not greater than 18 months, prior to the permit expiration date. [District Rule 2520, 5.2] Federally Enforceable Through Title V Permit

38. When a term is not defined in a Title V permit condition, the definition in the rule cited as the origin and authority for the condition in a Title V permits shall apply. [District Rule 2520, 9.1.1] Federally Enforceable Through Title V Permit

39. Compliance with permit conditions in the Title V permit shall be deemed in compliance with the following outdated SIP requirements: Rule 401 (Madera, Fresno, Kern, Kings, San Joaquin, Stanislaus, Tulare and Merced), Rule 110 (Fresno, Stanislaus, San Joaquin), Rule 109 (Merced), Rule 113 (Madera), and Rule 111 (Kern, Tulare, Kings). A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

40. Compliance with permit conditions in the Title V permit shall be deemed in compliance with the following applicable requirements: SJVUAPCD Rules 1100, sections 6.1 and 7.0 (12/17/92); 2010, sections 3.0 and 4.0 (12/17/92); 2031 (12/17/92); 2040 (12/17/92); 2070, section 7.0 (12/17/92); 2080 (12/17/92); 4101 (11/15/01); 4601, sections 5.1, 5.2, 5.3, 5.8 and 8.0 (10/31/01); 8021 (11/15/01); 8031 (11/15/01); 8041 (11/15/01); 8051 (11/15/01); 8061 (11/15/01); and 8071 (11/15/01). A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

41. On January 31, 2004, the initial Title V permit was issued. The reporting periods for the Report of Required Monitoring and the Compliance Certification Report are based upon this initial permit issuance date, unless alternative dates are approved by the District Compliance Division. These reports are due within 30 days after the end of the reporting period. [District Rule 2520] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-4140-1-3 **EXPIRATION DATE:** 04/30/2008

EQUIPMENT DESCRIPTION:
47.5 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION AND AN OXIDATION CATALYST

PERMIT UNIT REQUIREMENTS

1. Facilities C-603 and C-4140 are the same stationary source for SJVAPCD permitting purposes. [District Rule 2201] Federally Enforceable Through Title V Permit
2. 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 NSR Rule] Federally Enforceable Through Title V Permit
3. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. 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
5. Combustion turbine generator (CTG) and 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 Rule 2201] Federally Enforceable Through Title V Permit
6. The CTG shall be equipped with a continuous monitoring system to measure and record hours of operation, and fuel consumption. [District Rules 2201, 4001, and 4703] Federally Enforceable Through Title V Permit
7. Operation of the turbine shall not exceed 8,000 hours per calendar year. [District Rule 2201] Federally Enforceable Through Title V Permit
8. The CTG shall be equipped with continuous emission monitor (CEM) for NOx (before and after SCR system), CO, and O2. Continuous emission monitor shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. [District Rules 2201, 4001, and 4703] Federally Enforceable Through Title V Permit
9. 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
10. 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. [District Rule 1081] Federally Enforceable Through Title V Permit
11. 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, and the exhaust gas NOx and O2 concentrations. [40 CFR 60.334(a)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

12. CEM cycling times shall be those specified in 40 CFR, Part 51, Appendix P, Sections 3.4, 3.4.1 and 3.4.2, or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080, 6.4] Federally Enforceable Through Title V Permit

13. The continuous NOx and O2 monitoring system shall meet the performance specification requirements in 40 CFR 60, Appendix F, 40 CFR 51, Appendix P, and Part 60, Appendix B, or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080, 6.3, 6.5, 6.6 and 7.2] Federally Enforceable Through Title V Permit

14. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201, 3.1] Federally Enforceable Through Title V Permit

15. 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

16. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 0.25 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201; 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

17. If this unit is fired on PUC-regulated natural gas, then maintain on file copies of natural gas bills. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit

18. Thermal Stabilization Period shall be defined as the start up or shut down time during which the exhaust gas is not within the normal operating temperature range, not exceeding two hours. [District Rule 4703, 3.25] Federally Enforceable Through Title V Permit

19. During startup or shutdown of any gas turbine engine, combined emissions from the two gas turbine engines (Unit #1 and Unit #2) shall not exceed either of the following limits: NOx - 15.4 lb or CO - 15.4 lb per event. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

20. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in condition #21. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown durations shall not exceed a time period of one hour each per occurrence. [District Rule 2201] Federally Enforceable Through Title V Permit

21. Emission rates from this unit, excluding startup and shutdown, shall not exceed any of the following limits: PM10: 3.03 lb/hr, SOx (as SO2): 0.33 lb/hr, NOx (as NO2): 3.7 ppmvd @ 15% O2 and 6.3 lb/hr, VOC (as methane): 2.0 ppmvd @ 15% O2 and 1.19 lb/hr, or CO: 6.0 ppmvd @ 15% O2 and 6.2 lb/hr. All emission limits, except ammonia, are three hour rolling averages. [District Rules 2201, 4001, and 4703] Federally Enforceable Through Title V Permit

22. 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

23. 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] Federally Enforceable Through Title V Permit

24. Maximum daily emissions from this unit shall not exceed any of the following limits: PM10 - 72.8 lb/day; SOx (as SO2) - 7.8 lb/day; NOx (as NO2) - 151.5 lb/day; VOC - 28.7 lb/day; or CO - 150.3 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

25. Maximum annual emissions from this unit shall not exceed any of the following limits: NOx (as NO2) - 52,314 lb/year; VOC - 9,764 lb/year; CO - 51,947 lb/year; PM10 - 25,176 lb/year; or SOx (as SO2) - 2,710 lb/year. [District Rule 2201] Federally Enforceable Through Title V Permit

26. 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

27. Source testing to measure PM10, NOx (as NO2), VOC, CO, and ammonia emission rates, and fuel gas sulfur content shall be conducted at least once every twelve months. [District Rule 1081] Federally Enforceable Through Title V Permit

28. Compliance demonstration (source testing) shall be District witnessed or authorized, and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

29. The following test methods shall be used PM10: EPA Method 5 (front half and back half), 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, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. 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, 4001, and 4703] Federally Enforceable Through Title V Permit

30. The owner or operator shall provide source test information annually regarding the exhaust gas NOx and CO concentration corrected to 15% O2 (dry). EPA Methods 7E or 20 shall be used for NOx emissions. EPA Methods 10 or 10B shall be used for CO emissions. EPA Methods 3, 3A, or 20 shall be used for Oxygen content of the exhaust gas. [40 CFR 60.8(a) and District Rule 4703, 5.1, 6.3.1, 6.4.1, 6.4.2, and 6.4.3] Federally Enforceable Through Title V Permit

31. The owner or operator shall provide source test information annually regarding the demonstrated percent efficiency (EFF) as defined in District Rule 4703 (as amended 4/25/02), 5.1.1 and 6.4.6. [40 CFR 60.332(a) and (b) and District Rule 4703, 5.1.1 and 6.4.6] Federally Enforceable Through Title V Permit

32. All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device. [40 CFR 60.13(b)] Federally Enforceable Through Title V Permit

33. Results of the CEM system shall be averaged over a three hour period, using consecutive 15-minute sampling periods in accordance with either EPA Method 7E or EPA Method 20 for NOx, EPA Test 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. [40 CFR 60.13 and District Rule 4703, 5.1, 6.4] Federally Enforceable Through Title V Permit

34. The owner or operator shall not operate the gas turbine under load conditions, excluding the thermal stabilization period or reduced load period, which results in the measured CO emissions concentration exceeding 200 ppmv @ 15% O2. [District Rule 4703, 5.2] Federally Enforceable Through Title V Permit

35. The HHV and LHV of the fuel combusted shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a) and (b) and District Rule 4703, 6.4.5] Federally Enforceable Through Title V Permit

36. 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

37. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary of data shall be in the form and the manner prescribed by the APCO. [District Rule 1080, 7.1] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

38. Operators of CEM systems installed at the direction of the APCO shall submit a written report 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 emissions, nature and 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, 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, 8.0] Federally Enforceable Through Title V Permit

39. 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

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] 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] Federally Enforceable Through Title V Permit

42. APCO or an authorized representative shall be allowed to inspect, as he or she determines to be necessary, the monitoring devices required by this rule to ensure that such devices are functioning properly. [District Rule 1080, 11.0] Federally Enforceable Through Title V Permit

43. The owner or operator shall maintain records that contain the following: the occurrence and duration of any start-up, shutdown or malfunction, performance testing, evaluations, calibrations, checks, adjustments, any periods during which a continuous monitoring system or monitoring device is inoperative, maintenance of any CEM system that has been installed pursuant to District Rule 1080 (as amended 12/17/92), and emission measurements. [40 CFR 60.8(d) and District Rule 1080, 7.0] Federally Enforceable Through Title V Permit

44. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

45. 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 Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

46. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following subsumed requirements: Rules 108 (Fresno, Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus) and 109 (Madera) 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

47. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following subsumed requirements: Rules 108.1 (Fresno, Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus), and 110 (Madera) 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

48. 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

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

49. 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

50. 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

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-4140-2-3 **EXPIRATION DATE:** 04/30/2008

EQUIPMENT DESCRIPTION:
47.5 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL LM6000 NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH WATER SPRAY PREMIXED COMBUSTION SYSTEMS, SERVED BY A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION AND AN OXIDATION CATALYST

PERMIT UNIT REQUIREMENTS

1. Facilities C-603 and C-4140 are the same stationary source for SJVAPCD permitting purposes. [District Rule 2201] Federally Enforceable Through Title V Permit
2. 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 NSR Rule] Federally Enforceable Through Title V Permit
3. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. 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
5. Combustion turbine generator (CTG) and 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 Rule 2201] Federally Enforceable Through Title V Permit
6. The CTG shall be equipped with a continuous monitoring system to measure and record hours of operation, and fuel consumption. [District Rules 2201, 4001, and 4703] Federally Enforceable Through Title V Permit
7. Operation of the turbine shall not exceed 8,000 hours per calendar year. [District Rule 2201] Federally Enforceable Through Title V Permit
8. The CTG shall be equipped with continuous emission monitor (CEM) for NOx (before and after SCR system), CO, and O2. Continuous emission monitor shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. [District Rules 2201, 4001, and 4703] Federally Enforceable Through Title V Permit
9. 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
10. 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. [District Rule 1081] Federally Enforceable Through Title V Permit
11. 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, and the exhaust gas NOx and O2 concentrations. [40 CFR 60.334(a)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

12. CEM cycling times shall be those specified in 40 CFR, Part 51, Appendix P, Sections 3.4, 3.4.1 and 3.4.2, or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080, 6.4] Federally Enforceable Through Title V Permit

13. The continuous NOx and O2 monitoring system shall meet the performance specification requirements in 40 CFR 60, Appendix F, 40 CFR 51, Appendix P, and Part 60, Appendix B, or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080, 6.3, 6.5, 6.6 and 7.2] Federally Enforceable Through Title V Permit

14. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201, 3.1] Federally Enforceable Through Title V Permit

15. 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

16. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 0.25 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201; 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

17. If this unit is fired on PUC-regulated natural gas, then maintain on file copies of natural gas bills. [District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit

18. Thermal Stabilization Period shall be defined as the start up or shut down time during which the exhaust gas is not within the normal operating temperature range, not exceeding two hours. [District Rule 4703, 3.25] Federally Enforceable Through Title V Permit

19. During startup or shutdown of any gas turbine engine, combined emissions from the two gas turbine engines (Unit #1 and Unit #2) shall not exceed either of the following limits: NOx - 15.4 lb or CO - 15.4 lb per event. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

20. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmvd emission limits in condition #21. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown durations shall not exceed a time period of one hour each per occurrence. [District Rule 2201] Federally Enforceable Through Title V Permit

21. Emission rates from this unit, excluding startup and shutdown, shall not exceed any of the following limits: PM10: 3.03 lb/hr, SOx (as SO2): 0.33 lb/hr, NOx (as NO2): 3.7 ppmvd @ 15% O2 and 6.3 lb/hr, VOC (as methane): 2.0 ppmvd @ 15% O2 and 1.19 lb/hr, or CO: 6.0 ppmvd @ 15% O2 and 6.2 lb/hr. All emission limits, except ammonia, are three hour rolling averages. [District Rules 2201, 4001, and 4703] Federally Enforceable Through Title V Permit

22. 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

23. 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] Federally Enforceable Through Title V Permit

24. Maximum daily emissions from this unit shall not exceed any of the following limits: PM10 - 72.8 lb/day; SOx (as SO2) - 7.8 lb/day; NOx (as NO2) - 151.5 lb/day; VOC - 28.7 lb/day; or CO - 150.3 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

25. Maximum annual emissions from this unit shall not exceed any of the following limits: NOx (as NO2) - 52,314 lb/year; VOC - 9,764 lb/year; CO - 51,947 lb/year; PM10 - 25,176 lb/year; or SOx (as SO2) - 2,710 lb/year. [District Rule 2201] Federally Enforceable Through Title V Permit

26. 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

27. Source testing to measure PM10, NOx (as NO2), VOC, CO, and ammonia emission rates, and fuel gas sulfur content shall be conducted at least once every twelve months. [District Rule 1081] Federally Enforceable Through Title V Permit

28. Compliance demonstration (source testing) shall be District witnessed or authorized, and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

29. The following test methods shall be used PM10: EPA Method 5 (front half and back half), 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, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. 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, 4001, and 4703] Federally Enforceable Through Title V Permit

30. The owner or operator shall provide source test information annually regarding the exhaust gas NOx and CO concentration corrected to 15% O2 (dry). EPA Methods 7E or 20 shall be used for NOx emissions. EPA Methods 10 or 10B shall be used for CO emissions. EPA Methods 3, 3A, or 20 shall be used for Oxygen content of the exhaust gas. [40 CFR 60.8(a) and District Rule 4703, 5.1, 6.3.1, 6.4.1, 6.4.2, and 6.4.3] Federally Enforceable Through Title V Permit

31. The owner or operator shall provide source test information annually regarding the demonstrated percent efficiency (EFF) as defined in District Rule 4703 (as amended 4/25/02), 5.1.1 and 6.4.6. [40 CFR 60.332(a) and (b) and District Rule 4703, 5.1.1 and 6.4.6] Federally Enforceable Through Title V Permit

32. All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device. [40 CFR 60.13(b)] Federally Enforceable Through Title V Permit

33. Results of the CEM system shall be averaged over a three hour period, using consecutive 15-minute sampling periods in accordance with either EPA Method 7E or EPA Method 20 for NOx, EPA Test 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. [40 CFR 60.13 and District Rule 4703, 5.1, 6.4] Federally Enforceable Through Title V Permit

34. The owner or operator shall not operate the gas turbine under load conditions, excluding the thermal stabilization period or reduced load period, which results in the measured CO emissions concentration exceeding 200 ppmv @ 15% O2. [District Rule 4703, 5.2] Federally Enforceable Through Title V Permit

35. The HHV and LHV of the fuel combusted shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a) and (b) and District Rule 4703, 6.4.5] Federally Enforceable Through Title V Permit

36. 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

37. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary of data shall be in the form and the manner prescribed by the APCO. [District Rule 1080, 7.1] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

38. Operators of CEM systems installed at the direction of the APCO shall submit a written report 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 emissions, nature and 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, 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, 8.0] Federally Enforceable Through Title V Permit

39. 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

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] 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] Federally Enforceable Through Title V Permit

42. APCO or an authorized representative shall be allowed to inspect, as he or she determines to be necessary, the monitoring devices required by this rule to ensure that such devices are functioning properly. [District Rule 1080, 11.0] Federally Enforceable Through Title V Permit

43. The owner or operator shall maintain records that contain the following: the occurrence and duration of any start-up, shutdown or malfunction, performance testing, evaluations, calibrations, checks, adjustments, any periods during which a continuous monitoring system or monitoring device is inoperative, maintenance of any CEM system that has been installed pursuant to District Rule 1080 (as amended 12/17/92), and emission measurements. [40 CFR 60.8(d) and District Rule 1080, 7.0] Federally Enforceable Through Title V Permit

44. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

45. 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 Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

46. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following subsumed requirements: Rules 108 (Fresno, Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus) and 109 (Madera) 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

47. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following subsumed requirements: Rules 108.1 (Fresno, Kings, Merced, San Joaquin, Tulare, Kern, and Stanislaus), and 110 (Madera) 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

48. 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

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

49. 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

50. 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

ATTACHMENT C

Project Location and Site Plan

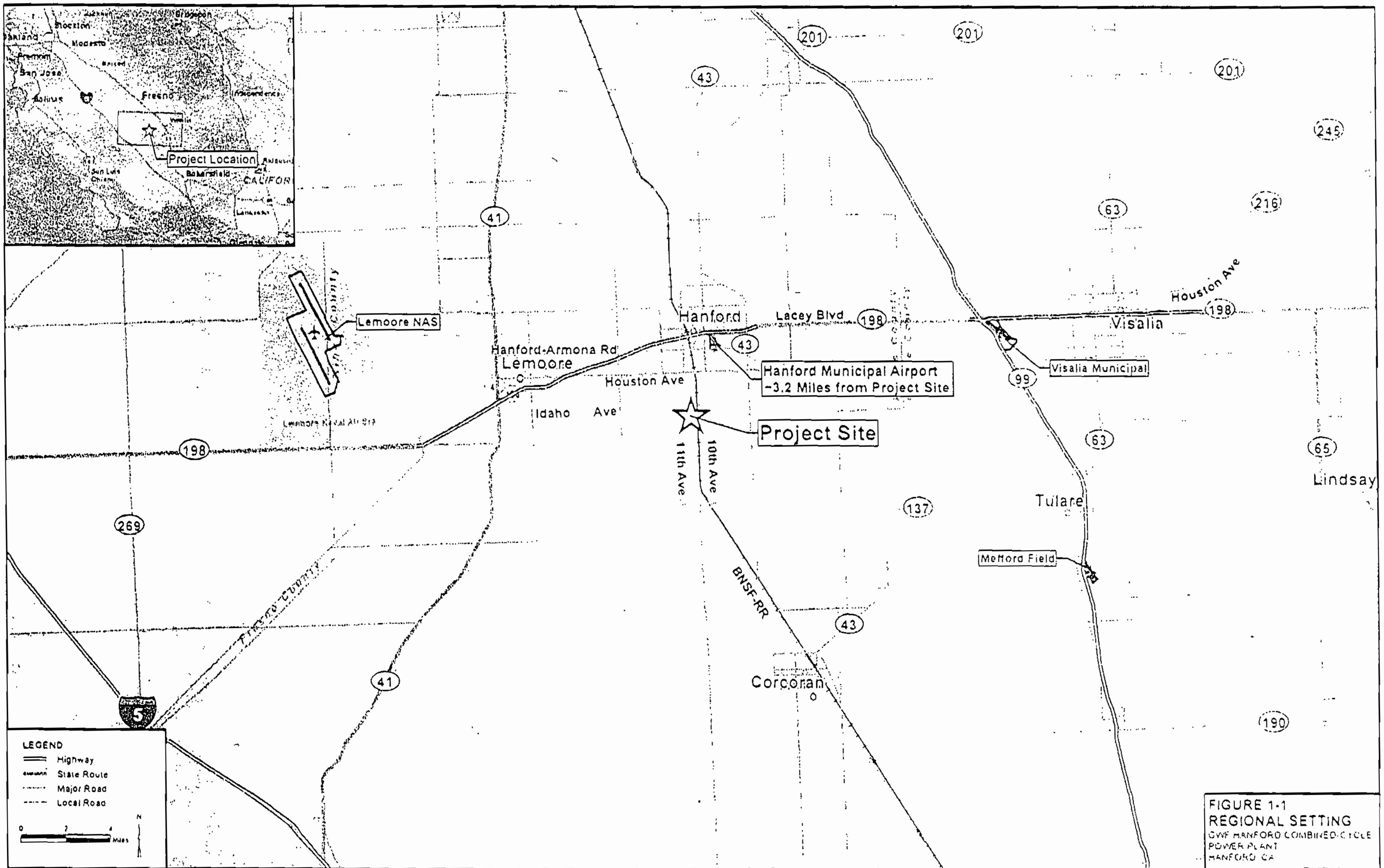
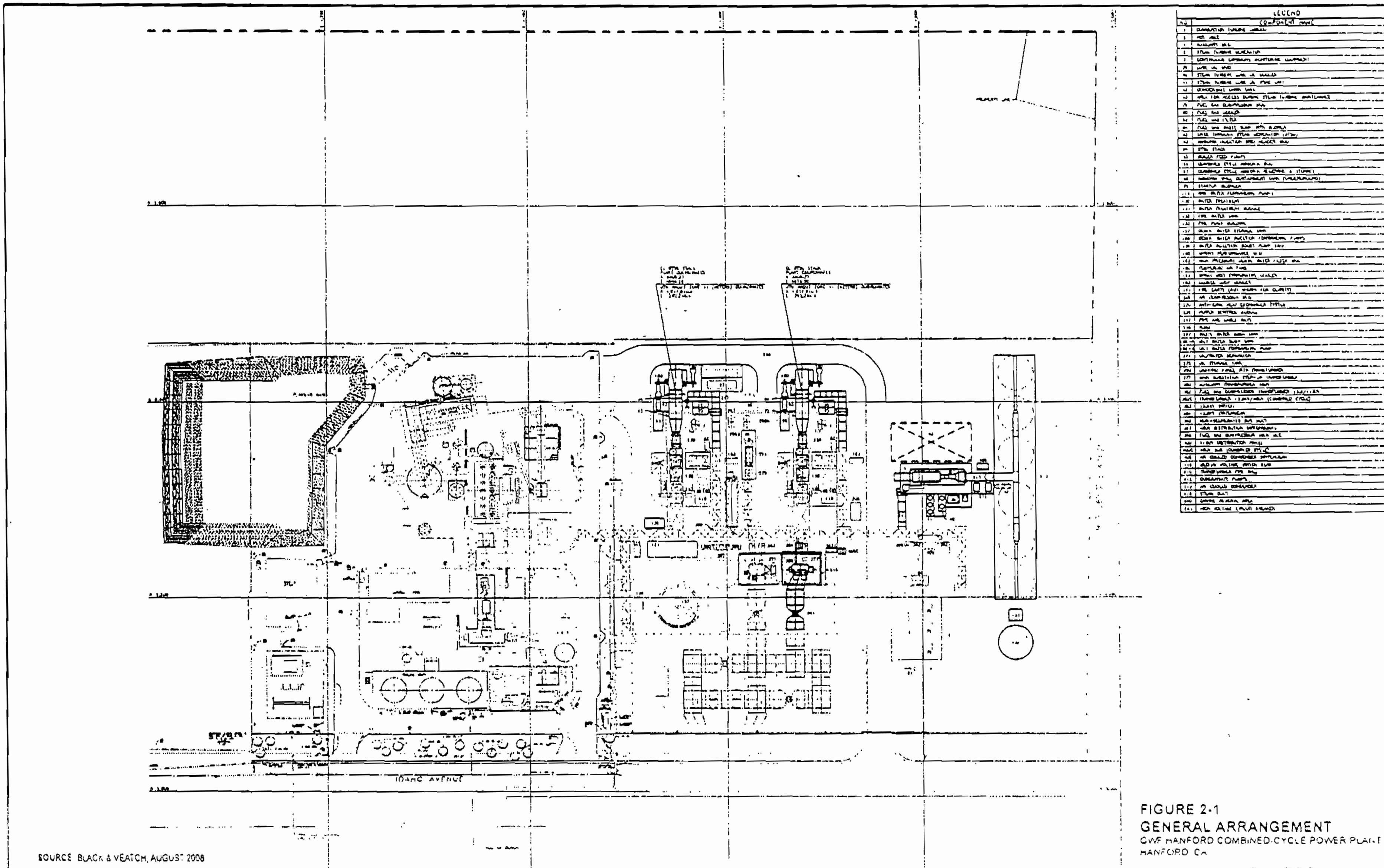


FIGURE 1-1
REGIONAL SETTING
GWF HANFORD COMBINED-CYCLE POWER PLANT
HANFORD CA



SOURCE: BLACK & VEATCH, AUGUST 2008

FIGURE 2-1
GENERAL ARRANGEMENT
GWF HANFORD COMBINED-CYCLE POWER PLANT
HANFORD CA

CH2MHILL

ATTACHMENT D

CTG Commissioning Period Emissions Data

GWF.Hanford Combined Cycle Power Plant
Table C2.1
Commissioning Emission Scenarios
September 2008

Number	Scenario	Turbine	Turbine Load Rate (%)	Scenario Modeled	Emission Rate per Turbine (lb/hr) 1 Hr NOx	1-Hr CO	8-Hr CO
2	Steam Blows	1 or 2	45	X	52.0	20.9	20 9
3	Steam Blows	Both	45	X	39.0	18.2	18.2
8	Bypass Operation until Steam Quality Achieved/STG Initial Roll and Trip Test	1 or 2	50		8.1	5.3	5.3
9	STG Load Testing	1 or 2	50		6.7	4 4	4.4
1	CTG Testing (OTSG HP Startup)	1 or 2	100		44.1	36.1	36.1
4	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	1 or 2	100	X	44.8	40.5	40.5
6	CTG Base Load / Commissioning of Ammonia system	1 or 2	100		23 4	36.1	36.1
10	STG Load Test	1 or 2	100		6.1	3.1	3.1
5	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	Both	100	X	44.8	40.5	40.5
7	CTG Base Load / Commissioning of Ammonia system	Both	100		19.1	34.2	34.2
11	Load Test STG / Combine Cycle (2X1)	Both	100		6.7	4.4	4.4
12	Combine Cycle testing	Both	100		5.7	3.7	3.7
13	RATA / Pre-performance Testing/Source Testing	Both	100		8.1	4.5	4.5
14	Source Testing	Both	100		8.1	4.5	4.5
15	Performance Testing	Both	100		7.1	3.8	3.8
16	CALISO Certification	Both	100		8.1	4.5	4.5
			Max		52.0	40.5	40.5

ATTACHMENT E

CTG Emissions Data

GWF Hanford Combined Cycle Power Plant
Table C2.2
Summary of Simple Cycle Turbine Emissions - Criteria Pollutants
September 2008

GWF Hanford Combined Cycle Conversion LM6000PC-SPRINT Simple Cycle Emissions						
Case Number	1	2	3	4	5	6
CTG Model	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	60%	100%	60%	100%	60%
CTG Inlet Air Cooling	Off	Off	Evap. Cooler	Evap. Cooler	Evap. Cooler	Evap. Cooler
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	15	15	61	61	115	115
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.24	0.24	0.24	0.24	0.24	0.24
Ambient Conditions						
Ambient Temperature, F	15.0	15.0	61.0	61.0	115.0	115.0
Ambient Relative Humidity, %	92.0	92.0	60.0	60.0	21.0	21.0
Atmospheric Pressure, psia	14.569	14.569	14.569	14.569	14.569	14.569
Combustion Turbine Performance						
CTG Performance Reference	GE	GE	GE	GE	GE	GE
CTG Inlet Air Conditioning Effectiveness, %	0	0	85	85	85	85
CTG Compressor Inlet Dry Bulb Temperature, F	15.0	15.0	56.1	56.1	84.6	84.6
CTG Compr. Inlet Relative Humidity, %	92.1	92.1	92.9	92.9	79.4	79.4
Inlet Loss, in. H2O	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H2O	12.0	12.0	12.0	12.0	12.0	12.0
CTG Load Level (percent of Base Load)	100%	60%	100%	60%	100%	60%
Gross CTG Output, kW	49,967	29,970	48,893	29,340	42,756	25,655
Gross CTG Heat Rate, Btu/kWh (LHV)	8,412	9,152	8,574	9,356	8,761	9,596
Gross CTG Heat Rate, Btu/kWh (HHV)	9,309	10,128	9,489	10,354	9,696	10,620
CTG Heat Input, MBtu/h (LHV)	420.3	274.3	419.2	274.5	374.6	246.2
CTG Heat Input, MBtu/h (HHV)	465.2	303.6	463.9	303.8	414.6	272.5
CTG Water/Steam Injection Flow, lb/h	22,452	10,639	18,510	11,235	13,804	8,370
Injection Fluid/Fuel Ratio	1.0	0.7	0.8	0.8	0.7	0.7
CTG Exhaust Flow, lb/h	1,119,571	860,648	1,048,369	833,496	954,633	735,795
CTG Exhaust Temperature, F	735	732	847	789	873	842
Combustion Turbine Fuel						
Total CTG Fuel Flow, lb/h	22,1[illegible]	14,450	22,090	14,460	19,739	12,973
CTG Fuel Temperature, F	76	76	76	76	76	76
CTG Fuel LHV, Btu/lb	18,981	18,981	18,981	18,981	18,981	18,981
CTG Fuel HHV, Btu/lb	21,006	21,006	21,006	21,006	21,006	21,006
HHV/LHV Ratio	1.1067	1.1067	1.1067	1.1067	1.1067	1.1067
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	68.44%	68.44%	68.44%	68.44%	68.44%	68.44%
H2	21.38%	21.38%	21.38%	21.38%	21.38%	21.38%
N2	8.80%	8.80%	8.80%	8.80%	8.80%	8.80%
O2	1.37%	1.37%	1.37%	1.37%	1.37%	1.37%
S	0.00074%	0.00074%	0.00074%	0.00074%	0.00074%	0.00074%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	0.24	0.24	0.24	0.24	0.24	0.24
Stack Emissions						
Stack Exhaust Analysis - Volume Basis - Wet						
Ar	0.92%	0.93%	0.91%	0.92%	0.90%	0.90%
CO2	3.18%	2.72%	3.38%	2.80%	3.30%	2.82%
H2O	9.33%	7.27%	10.39%	8.68%	11.45%	10.12%
N2	73.08%	74.34%	72.39%	73.30%	71.51%	72.20%
O2	13.49%	14.73%	12.93%	14.30%	12.84%	13.95%
SO2 (after SO2 oxidation)	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%
SO3 (after SO2 oxidation)	0.000005%	0.000004%	0.000005%	0.000004%	0.000005%	0.000004%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	735	732	847	789	873	842
Stack Diameter, ft (estimated)	9.6	9.6	9.6	9.6	9.6	9.6
Stack Flow, lb/h	1,119,571	860,648	1,048,369	833,496	954,633	735,795
Stack Flow, scfm	250,734	191,494	235,534	186,425	215,429	165,431
Stack Flow, acfm	605,501	442,660	597,570	451,755	557,187	418,127
Stack Exit Velocity, ft/s	133	101	137	103	127	96
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)						
NOx, ppmvd (dry, 15% O2)	2.5	2.5	2.5	2.5	2.5	2.5
NOx, lb/h as NO2	4.2	2.8	4.2	2.8	3.8	2.5
NOx, lb/MBtu (HHV) as NO2	0.0101	0.0101	0.0101	0.0101	0.0100	0.0102
SCR NH3 slip, ppmvd (dry, 15% O2)	10.0	10.0	10.0	10.0	10.0	10.0
SCR NH3 slip, lb/h	6.2	4.1	6.2	4.1	5.6	3.7
Stack CO Emissions with the Effects of Catalytic Reduction (CO Catalyst)						
CO, ppmvd (dry, 15% O2)	3.0	3.0	1.8	2.9	2.2	2.7
CO, lb/h	3.1	2.0	1.8	2.1	2.2	1.8
CO, lb/MBtu (HHV)	0.0067	0.0067	0.0039	0.0069	0.0053	0.0066

GWF

Hanford Combined Cycle Conversion

LM6000PC-SPRINT Simple Cycle Emissions

Case Number	1	2	3	4	5	6
CTG Model	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	60%	100%	60%	100%	60%
CTG Inlet Air Cooling	Off	Off	Evap Cooler	Evap Cooler	Evap Cooler	Evap Cooler
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	15	15	63	63	115	115
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.24	0.24	0.24	0.24	0.24	0.24
Stack SO2 Emissions without the Effects of SO2 Scrubber						
SO2, ppmvd (dry, 15% O2)	0.11	0.13	0.11	0.13	0.13	0.13
SO2, lb/h	0.31	0.20	0.31	0.20	0.27	0.18
SO2, lb/MBtu (HHV)	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
Stack VOC Emissions with the Effects of Catalytic Reduction (CO Catalyst)						
VOC, ppmvd (dry, 15% O2)	2.0	2.0	0.3	0.8	0.3	0.8
VOC, lb/h as CH4	1.2	0.4	0.5	0.3	0.4	0.3
VOC, lb/MBtu (HHV)	0.0025	0.0025	0.0011	0.0010	0.0010	0.0010
PM10 with the Effects of SO2 Oxidation						
PM10 Emissions - Front and Back Half Catch						
PM10, lb/h	2.2	2.1	2.2	2.1	2.1	2.1
PM10, lb/MBtu (HHV)	0.0046	0.0068	0.0045	0.0068	0.0051	0.0075
PM2.5 with the Effects of SO2 Oxidation						
PM2.5 Emissions - Front and Back Half Catch						
PM2.5, lb/h	2.2	2.1	2.2	2.1	2.1	2.1
PM2.5, lb/MBtu (HHV)	0.0046	0.0058	0.0046	0.0068	0.0051	0.0075
Additional Emissions						
CTG Exhaust						
O2, lb/h	171,178	142,728	154,101	134,909	140,025	116,793
CO2, lb/h	55,528	36,241	55,493	36,267	49,484	32,530
H2O, lb/h	66,610	39,687	69,758	45,119	70,295	47,729

Notes:

1. The emissions estimates shown in the table above are per stack. Emission estimates are expected and do not include any margin. Permitting margins should be applied by permitting engineer.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99% O2.
3. Standard conditions are defined as 59° F, 14.696 psia. Norm conditions are defined as 32° F, 14.696 psia.
4. All ppm values are based on CH4 calibration gas.
5. The CTG performance and emissions is based on GE APPS data.
6. The VOC/UHC ratio is assumed to be 20% for natural gas firing (typical for GE turbines).
7. UHC values shown do not include the effects of oxidation in the CO catalyst.
8. The O2 reduction in the CO catalyst is negligible and not included in the analysis.
9. The H2O increase in the SCR catalyst is negligible and not included in the analysis.
10. The front half catch of particulate emissions is assumed to be half the amount of the front and back half catch.
11. Ammonium sulfates created downstream of the SCR are included in front & back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.
12. B&V estimates of lb/h of pollutant emissions were adjusted, where applicable, to meet the values specified by GWF (VOC and PM10). VOC estimates for all cases except emissions on 15°F were adjusted based on 100% load emissions at 63F provided by GWF. All the PM10 emissions were adjusted based on value provided by GWF at 100% load on 63°F case.
13. SCR and CO Catalyst are included for emission reduction and are designed to control NOx and CO emissions to meet permit limits provided by GWF. The revised simple cycle permit limits for NOx, CO and VOC are 2.5 ppmvd @15% O2, 3.0 ppmvd @15%O2 and 2.0 ppmvd @15% O2 respectively. VOC conversion across the CO catalyst is assumed to be 30% for 63°F and 115°F ambient cases. VOC catalyst efficiency for 15°F cases is adjusted so that VOC at stack equals target level of 2 ppmvd @ 15%O2.
14. Sulfur content in fuel gas was assumed to be 0.24 grains/100 SCF.
15. The estimated PM2.5 emissions are assumed to be 100% of PM10 emissions as per GE.
16. SO2 oxidation rate of 20% in CO catalyst was used for emission estimates. Permitting engineer should apply necessary margins if the assumed SO2 oxidation rate in CO catalyst varies from 20%.
17. The estimates for SO2 do not account for any reduction in SO2 emissions because of the oxidation of SO2 to SO3 in CTG, SCR and CO catalyst respectively.
18. SO3 and subsequent PM10 and PM2.5 values are calculated based on the SO2 to SO3 conversion rates noted for the CTG, SCR and CO catalyst.
19. The estimated ammonia slip (lb/hr) in SCR is based on the ammonia slip concentration (10 ppmvd @15%O2) as per GWF specified simple cycle permit limits.

GWF Hanford Combined Cycle Power Plant
Table C2.3
Summary of Combined Cycle Turbine Emissions - Criteria Pollutants
September 2008

GWF
Hanford Combined Cycle Conversion
LM6000PC-SPRINT Combined Cycle Emissions

Case Number	1	2	3	4	5	6
CTG Model	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	60%	100%	60%	100%	60%
CTG Inlet Air Cooling	Off	Off	Evap Cooler	Evap Cooler	Evap Cooler	Evap Cooler
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	15	15	61	61	115	115
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.24	0.24	0.24	0.24	0.24	0.24
Ambient Conditions						
Ambient Temperature, F	15.0	15.0	61.0	61.0	115.0	115.0
Ambient Relative Humidity, %	92.0	92.0	60.0	60.0	21.0	21.0
Atmospheric Pressure, psia	14.563	14.569	14.569	14.569	14.569	14.569
Combustion Turbine Performance						
CTG Performance Reference	GE	GE	GE	GE	GE	GE
CTG Inlet Air Conditioning Effectiveness, %	0	0	85	85	85	85
CTG Compressor Inlet Dry Bulb Temperature, F	15.0	15.0	56.1	56.1	84.6	84.6
CTG Compr. Inlet Relative Humidity, %	92.1	92.1	92.9	92.9	79.4	79.4
Inlet Loss, in. H2O	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H2O	12.0	12.0	12.0	12.0	12.0	12.0
CTG Load Level (percent of Base Load)	100%	60%	100%	60%	100%	60%
Gross CTG Output, kW	49,967	29,970	48,893	29,340	42,756	25,655
Gross CTG Heat Rate, Btu/kWh (LHV)	8,412	9,152	8,574	9,356	8,761	9,596
Gross CTG Heat Rate, Btu/kWh (HHV)	9,309	10,128	9,489	10,354	9,695	10,620
CTG Heat Input, MBtu/h (LHV)	420.3	274.3	419.2	274.5	374.6	246.2
CTG Heat Input, MBtu/h (HHV)	465.2	303.6	463.9	303.8	414.6	272.5
CTG Water/Steam Injection Flow, lb/h	22,457	10,639	18,510	11,235	13,804	8,370
Injection Fluid/Fuel Ratio	1.0	0.7	0.8	0.8	0.7	0.7
CTG Exhaust Flow, lb/h	1,119,571	559,648	1,048,369	833,495	954,633	735,795
CTG Exhaust Temperature, F	785	732	847	789	873	842
Combustion Turbine Fuel						
Total CTG Fuel Flow, lb/h	22,140	14,450	22,090	14,460	19,730	12,970
CTG Fuel Temperature, F	76	76	75	76	75	76
CTG Fuel LHV, Btu/lb	18,981	18,981	18,981	18,981	18,981	18,981
CTG Fuel HHV, Btu/lb	21,006	21,006	21,006	21,006	21,006	21,006
HHV/LHV Ratio	1.1067	1.1067	1.1067	1.1067	1.1067	1.1067
CTG Fuel Composition (Ultimate Analysis by Weight)						
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	68.44%	68.44%	68.44%	68.44%	68.44%	68.44%
H2	21.38%	21.38%	21.38%	21.38%	21.38%	21.38%
N2	8.80%	8.80%	8.80%	8.80%	8.80%	8.80%
O2	1.37%	1.37%	1.37%	1.37%	1.37%	1.37%
S	0.00074%	0.00074%	0.00074%	0.00074%	0.00074%	0.00074%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	0.24	0.24	0.24	0.24	0.24	0.24
Stack Exhaust Analysis - Volume Basis - Wet						
Ar	0.92%	0.93%	0.91%	0.92%	0.90%	0.90%
CO2	3.18%	2.72%	3.38%	2.80%	3.30%	2.82%
H2O	9.33%	7.27%	10.39%	8.68%	11.45%	10.12%
N2	73.08%	74.34%	72.39%	73.30%	71.51%	72.20%
O2	13.49%	14.73%	12.93%	14.30%	12.84%	13.95%
SO2 (after SO2 oxidation)	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%
SO3 (after SO2 oxidation)	0.000005%	0.000004%	0.000005%	0.000004%	0.000005%	0.000004%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	288	284	272	269	283	269
Stack Diameter, ft (estimated)	9.6	9.6	9.6	9.6	9.6	9.6
Stack Flow, lb/h	1,119,571	860,648	1,048,369	833,496	954,633	735,795
Stack Flow, scfm	250,784	191,494	235,534	186,425	215,429	165,431
Stack Flow, acfm	363,861	276,411	334,430	263,663	310,415	234,105
Stack Exit Velocity, ft/s	83.2	63.2	76.5	60.3	71.0	53.6
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)						
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0	2.0	2.0
NOx, lb/h as NO2	3.4	2.2	3.4	2.2	3.0	2.0
NOx, lb/MBtu (HHV) as NO2	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
SCR NH3 slip, ppmvd (dry, 15% O2)	5.0	5.0	5.0	5.0	5.0	5.0
SCR NH3 slip, lb/h	3.1	2.0	3.1	2.0	2.8	1.8

GWF

Hanford Combined Cycle Conversion

LM6000PC-SPRINT Combined Cycle Emissions

Case Number	1	2	3	4	5	6
CTG Model	LM6000	LM6000	LM6000	LM6000	LM6000	LM6000
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	50%	100%	60%	100%	50%
CTG Inlet Air Cooling	Off	Off	Evap Cooler	Evap Cooler	Evap Cooler	Evap Cooler
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	15	15	63	63	115	115
HRSG Duct Firing	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.24	0.24	0.24	0.24	0.24	0.24
Stack CO Emissions with the Effects of Catalytic Reduction (CO Catalyst)						
CO, ppmvd (dry, 15% O2)	3.00	3.00	1.80	1.58	1.75	1.75
CO, lb/h	3.10	2.04	1.80	2.25	1.75	2.63
CO, lb/MMBtu (HHV)	0.01	0.01	0.00	0.01	0.00	0.01
Stack SO2 Emissions without the Effects of SO2 Scrubber, after SO2 Oxidation						
SO2, ppmvd (dry, 15% O2)	0.13	0.13	0.13	0.13	0.13	0.13
SO2, lb/h	0.31	0.20	0.31	0.20	0.27	0.13
SO2, lb/MMBtu (HHV)	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
Stack VOC Emissions with the Effects of Catalytic Reduction (CO Catalyst)						
VOC, ppmvd (dry, 15% O2)	2.0	2.0	0.8	0.8	0.8	0.8
VOC, lb/h as CH4	1.2	0.8	0.5	0.3	0.4	0.3
VOC, lb/MMBtu (HHV)	0.0025	0.0025	0.0011	0.0010	0.0010	0.0010
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]						
PM10 Emissions - Front and Back Half Catch						
PM10, lb/h	2.2	2.1	2.2	2.1	2.1	2.1
PM10, lb/MMBtu (HHV)	0.0046	0.0068	0.0046	0.0068	0.0051	0.0075
PM2.5 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]						
PM2.5 Emissions - Front and Back Half Catch						
PM2.5, lb/h	2.2	2.1	2.2	2.1	2.1	2.1
PM2.5, lb/MMBtu (HHV)	0.0046	0.0068	0.0046	0.0068	0.0051	0.0075
Additional Emissions						
CTG Exhaust						
O2, lb/h	171,178	142,723	154,101	134,909	140,023	116,793
CO2, lb/h	55,528	36,241	55,403	36,267	49,484	32,530
H2O, lb/h	66,610	39,687	69,768	46,119	70,295	47,723

Notes:

1. The emissions estimates shown in the table above are per stack. Emission estimates are expected and do not include any margin. Permitting margins should be applied by permitting engineer.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99% O2
3. Standard conditions are defined as 59°F, 14.696 psia. Norm conditions are defined as 32°F, 14.696 psia
4. All ppm values are based on CH4 calibration gas
5. The CTG performance and emissions is based on GE APPS data
6. The VOC/UHC ratio is assumed to be 20% for natural gas firing (typical for GE turbines)
7. UHC values shown do not include the effects of oxidation in the CO catalyst
8. The O2 reduction in the CO catalyst is negligible and not included in the analysis
9. The H2O increase in the SCR catalyst is negligible and not included in the analysis
10. The front half catch of particulate emissions is assumed to be half the amount of the front and back half catch
11. Ammonium sulfates created downstream of the SCR are included in front half particulates and front/back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions
12. [illegible] GWF (VOC and PM10). VOC estimates for all cases except emissions on 15°F were adjusted based on 100% load emissions at 63F provided by GWF. All the PM10 emissions were adjusted based on value provided by GWF at 100% load on 63°F case
13. SCR and CO Catalyst are included for emission reduction and are designed to control NOx and CO emissions to meet emission limits provided by GWF. The combined cycle limits for NOx, CO and VOC are set to 2.0 ppmvd @15% O2, 3.0 ppmvd @15%O2 and 2.0 ppmvd @15% O2 respectively as per GWF guidelines. VOC conversion across the CO catalyst is assumed to be 30% for 63°F and 115°F ambient cases. VOC catalyst efficiency for 15°F cases is adjusted so that VOC at stack equals target level of 2 ppmvd @ 15%O2
14. Sulfur content in fuel gas was assumed to be 0.24 grains/100 SCF
15. The estimated PM2.5 emissions are assumed to be 100% of PM10 emissions as per GE
16. SO2 oxidation rate of 20% in CO catalyst was used for emission estimates. Permitting engineer should apply necessary margins if the assumed SO2 oxidation rate in CO catalyst varies from 20%
17. The estimates for SO2 do not account for any reduction in SO2 emissions because of the oxidation of SO2 to SO3 in CTG, SCR and CO catalyst respectively
18. SO3 and subsequent PM10 and PM2.5 values are calculated based on the SO2 to SO3 conversion rates noted for the CTG, SCR and CO catalyst
19. The estimated ammonia slip (lb/hr) in SCR is based on the ammonia slip concentration (5 ppmvd @15%O2) as per GWF specified limits
20. A equivalent stack diameter of 12 ft is used for stack velocity estimation
21. Estimated stack temperatures are obtained from Thermoflow estimated combined cycle performance data

simple-cycle mode. GWF Hanford will continue to use the existing aqueous ammonia storage system, ammonia vaporization and injection system, and monitoring equipment and sensors.

CO and VOCs emissions will be controlled using an oxidation catalyst located in the OTSGs. CO would be controlled to 3 ppmvd or less at 15 percent O_2, and VOCs would be controlled to 2 ppmvd or less at 15 percent O_2 while operating under both combined- and simple-cycle modes.

Particulate and sulfur dioxide emissions will be controlled by using inherently low sulfur natural gas as the sole fuel for the LM6000 turbines. In addition, the LM6000 turbines will employ high-efficiency inlet air filtration to remove particulate matter from the inlet air.

Start-up and Shutdown Emissions

The maximum facility start-up and shutdown emission rates for both operating modes are presented in Table 3.1-4, on a pound per event (lb/event) basis. These emissions are based on vendor data. GWF Hanford will have the ability to operate in either simple- or combined-cycle mode. Each turbine start-up would include a simple-cycle start-up. If the turbine transitions to combined-cycle operation then a combined-cycle start-up would occur and the total emissions for that start-up would be the sum of the simple-cycle and combined-cycle start-up emissions. Similarly each turbine shutdown includes a simple-cycle shutdown. A combined-cycle shutdown only occurs if the plant was operating in combined-cycle mode.

TABLE 3.1-4
LM6000 Start-up/Shutdown Emission Rates

	NO_x	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$
Simple-cycle						
Start (lb/event) [a]	7.7	7.7	0.7	0.1	0.1	0.1
Stop (lb/event) [b]	7.7	7.7	0.7	0.1	0.2	0.2
Combined-cycle						
Start (lb/event) [c]	6.1	3	0.5	0.3	2.2	2.2
Shutdown (lb/event) [d]	2.1	1.0	0.2	0.1	0.8	0.8

[a] Simple-cycle start is based on a 10-minute start cycle.

[b] Simple-cycle stop is based on a 10-minute stop cycle.

[c] Combined-cycle start is based on a 60-minute start cycle.

[d] Combined-cycle stop is based on a 20-minute stop cycle.

Steady-state Operating Emissions

GWF Hanford's CTGs will have the capability of operating in either a simple-cycle or combined-cycle mode. As such, the emission concentrations for both modes differ slightly for NO_x. The turbine operational emission rates for steady-state operations have been estimated based on the combined maximum heat input rating and conservative estimates of annual operation. The emission rates for the LM6000 unit are shown in Table 3.1-5. Emission estimates are provided in Attachment C.

ATTACHMENT F

SJVAPCD BACT Guidelines 3.1.4, 3.4.6 and 3.4.8

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.4*

Last Update: 6/30/2001

Emergency Diesel I.C. Engine Driving a Fire Pump

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO		Oxidation Catalyst	
NOx	Certified NOx emissions of 6.9 g/bhp-hr or less		
PM10	0.1 grams/bhp-hr (if TBACT is triggered) (corrected 7/16/01) 0.4 grams/bhp-hr (if TBACT is not triggered)		
SOx	Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available.		
VOC	Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]	Catalytic Oxidation	

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.6*

Last Update: 10/1/2002

Gas Turbine - > 10 MW and < 50 MW, Uniform Load, with Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmvd @ 15% O2 (Oxidation catalyst, or equal)		
NOx	2.5 ppmvd @ 15% O2, based on a three-hour rolling average (SCR with steam or water injection, or equal)	2.0 ppmvd @15% O2 (SCONOx™ system with steam or water injection, or equal)	
PM10	Air inlet cooler/filter, lube oil vent coalescer and either PUC regulated natural gas or non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal.		
SOx	PUC-regulated natural gas or Non-PUC-regulated gas with no more that 0.75 gr S/100 dscf, or equal.		
VOC	2.0 ppmvd @ 15% O2 (Oxidation catalyst, or equal)		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

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San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.8*

Last Update: 10/1/2002

Gas Turbine - < 50 MW, Uniform Load, Without Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).	90% control efficiency (SCONOx system, or equal).	
NOx	5.0 ppmvd** @ 15% O2, based on a three-hour average (high temp SCR, or equal).	1. 2.5 ppmv @ 15% O2 (SCONOx system, or equal). 2. 3.0 ppmv (Dry Low-NOx combustors and 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 < 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal).	1. 90% control efficiency (SCONOx system, or equal).	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

ATTACHMENT G

Simple Cycle Mode Top Down BACT Analysis
(C-4140-1-5 and C-4140-2-5)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.8 identifies achieved in practice BACT as the following:

- 5.0 ppmvd NO_X @ 15% O_2, based on a three-hour average (high temperature SCR, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.8 identifies technologically feasible BACT as the following:

- 2.5 ppmvd NO_X @ 15% O_2 (SCONO$_X$ system, or equal)
- 3.0 ppmvd NO_X @ 15% O_2 (dry low-NO_X combustors and SCR, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.8 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. 2.5 ppmvd NO_X @ 15% O_2 (SCONO$_X$ system, or equal)
2. 3.0 ppmvd NO_X @ 15% O_2 (dry low-NO_X combustors and SCR, or equal)
3. 5.0 ppmvd NO_X @ 15% O_2, based on a three-hour average (high temperature 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 2.5 ppmv @ 15% O_2 (1-hour average). This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.5 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 2.5 ppmv @ 15% O_2 (1-hour average). Therefore, BACT for NO_X emissions is satisfied.

ATTACHMENT H

Combined Cycle Mode Top Down BACT Analysis
(C-4140-1-5 and C-4140-2-5)

I. Steady State NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.6 identifies achieved in practice BACT as the following:

- 2.5 ppmvd NO_X @ 15% O_2, based on a three-hour rolling average (SCR with steam or water injection, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.6 identifies technologically feasible BACT as the following:

- 2.0 ppmvd NO_X @ 15% O_2 ($SCONO_X$ system with steam or water injection, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.6 does not identify any alternate basic equipment BACT control alternatives for NO_X emissions.

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 ($SCONO_X$ system with steam or water injection, or equal)
2. 2.5 ppmvd NO_X @ 15% O_2 (SCR with steam or water injection, 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), 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 steady state operation from this emission unit is determined to be the use of a SCONO$_X$ system with emissions of less than or equal to 2.0 ppmv @ 15% O_2 (1-hour average), or an equivalent control technology. 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 for NO_X emissions is satisfied and no further discussion is required.

II. Startup/Shutdown NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.6 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) as a part of the GWF Energy projects associated with this GWF Hanford project (refer to GWF Henrietta, FID C-3929, and GWF Tracy, FID N-4597), 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.

The US electric power industry has changed dramatically since the downturn of the gas turbine-based market in the early 2000's. In prior years, nearly all combined-cycle plants were planned, permitted and built with the expectation to be operated predominantly in base load. With the addition of excess generating capacity in the industry coupled with rising natural gas prices, many new power plants will have to address a new set of challenges posed by nightly and weekend shutdowns and subsequent fast start-up requirements to remain economically viable.

In order to improve power plant operating flexibility, additional control technologies or strategies are being incorporated in to new combined cycle power plant designs. The following three control strategies could potentially be applied for GWF Hanford's combined cycle power plant being modified within this project:

Rapid start to maximize generation opportunities
Lower startup emissions
Lower operating costs (high start efficiency)

The following control technologies incorporate the necessary requirements to perform the three control strategies listed above and allow for combined cycle plants to perform rapid turbine startups and reduce startup emissions. Therefore, the following control strategies will be included as a part of the top-down BACT analysis for this project:

- General Electric Rapid Response Startup Technology
- General Electric OpFlex Startup Technology
- Siemens Fast Start Technology

EPA has also 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, the following control strategy will also be included as a part of the top-down BACT analysis for this project.

- SCR System Operation with NH_3 Injection at Feasible Catalyst Temperatures during Startup and Shutdown Periods

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

Both the GE Rapid Response and Siemens Fast Start Technologies incorporate similar pieces of equipment from a conventionally designed combined cycle power plant design that result in reduced startup durations and reductions in overall startup NO_X emissions. The key components of these systems are as follows:

- Installation of a new heat recovery steam generator that is designed with features to accommodate the high temperature exhaust gas flow during rapid startup of the gas turbine which can allow the turbine to reach 100% load within 15 minutes as opposed to a conventional combined cycle plant where the gas turbine can take up to 90 minutes to reach 100% load as it goes through a much slower startup process due to the design of the conventional heat recovery steam generator (not including any additional startup time necessary for the emission control devices to come up to their operating temperatures and pressures and begin working at their maximum efficiency).
- Installation of a steam bypass system to allow 100% of the steam being generated after the rapid startup of the gas turbine to bypass the steam turbine until the steam turbine is brought up to its typical operating temperature and pressure and can handle the entire amount of steam the gas turbine and heat recovery steam generator produce.
- Installation of a fuel heating system to pre-heat the natural gas being burned in the turbine to increase its startup efficiency and shorten the startup duration.

Pursuant to Scott Dayer and Gordon Smith with General Electric, General Electric's Rapid Response technology is only feasible with combined cycle power plants configured with GE Frame 7A gas turbines and portions of the technology may potentially be feasible with their smaller GE Frame 7E turbines. In addition, 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.(1) As discussed above, GWF Hanford operates two GE LM6000 gas turbines. These turbines are not F-class turbines. Therefore, the General Electric Rapid Response Technology and the Siemens Fast Start Technology are not feasible for LM6000 gas turbines and no further discussion is required.

(1) Refer to http://www.powergeneration.siemens.com/NR/rdonlyres/97BD3507-B414-44E0-AA97-1CD8AAB5CCAE/0/PowerGen2007PaperFinal .pdf.

Note that GWF Hanford is proposing to install a once through heat recover steam generator which will allow the gas turbines to reach 100% load within 10 minutes of starting up (not including any additional startup time necessary for the emission control devices to come up to their operating temperatures and pressures and begin working at their maximum efficiency). They will also be installing a steam bypass system on the steam turbine until it is able to handle 100% of the steam being generated by the rapid start of the gas turbine and once through heat recovery steam generator and is operating at its typical temperature and pressure. And the gas turbines are already equipped with a fuel heating system. Therefore, even though the General Electric Rapid Response technology is not feasible for GWF Hanford's General Electric LM6000 configuration, they are proposing to incorporate alternative control technologies and strategies that can be considered equivalent.

General Electric's OpFlex Technology is a software solution that optimizes the gas turbine combustion process, extending low-emissions operation to lower load levels. It increases gas turbine turndown capability, enabling power generators to significantly reduce fuel costs and CO_2 emissions associated with low-load operation, while maintaining low NO_X and CO_2 emission levels. Pursuant to various articles found, OpFlex technology is only suited for customers operating General Electric 7FA+e gas turbines.(1) As discussed above, GWF Hanford operates two General Electric LM6000 gas turbines. Therefore, the Opflex Technology is not feasible for their installations and no further discussion is required.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The only remaining control option from step 2 above is as follows:

1. SCR System Operation with NH_3 Injection at Feasible Catalyst Temperatures during Startup and Shutdown Periods

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 and is proposing that NH_3 injection will occur at the minimum feasible catalyst temperature during a startup and the maximum feasible catalyst temperature during a shutdown. This is the only 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.

(1) Refer to http://ge.ecomagination.com/products/opflex-turndown.html and http://ewsscg.socalgas.com/business/gasQuality/documents/elec_gen_ge_announces_opflex.pdf.

Step 5 - Select BACT

BACT for startup and shutdown periods for this emission unit is determined to be the use of an SCR system with ammonia injection, with NH_3 being injected at the minimum feasible catalyst temperature during a startup and the maximum feasible catalyst temperature during a shutdown. The facility has proposed to control the NO_X emissions from each of their turbines with an SCR system. GWF Hanford will begin injecting NH_3 in to the SCR system at the earliest feasible catalyst temperature during a startup. GWF will also continue to inject NH_3 in to the SCR system until the latest feasible temperature during a shutdown. Therefore, BACT for NO_X emissions during startup and shutdown periods is satisfied and no further discussion is required.

III. Steady State and Startup/Shutdown VOC Top-Down BACT Analysis

Step 1 - <u>Identify All Possible Control Technologies</u>

SJVAPCD BACT Clearinghouse Guideline 3.4.6 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% O_2 (oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.6 does not identify any technologically feasible BACT control alternatives for VOC emissions.

SJVAPCD BACT Clearinghouse Guideline 3.4.6 does not identify any alternate basic equipment BACT control alternatives for VOC emissions.

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>

1. 2.0 ppmvd @ 15% O_2 (oxidation catalyst, or equal)

Step 4 - <u>Cost Effectiveness 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 the use of an oxidation catalyst with VOC emissions of 2.0 ppmv @ 15% O_2 (3-hour average), 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 oxidation catalyst with VOC emissions of less than or equal to 2.0 ppmv @ 15% O_2 (3-hour average), or an equivalent control technology. The facility has proposed to use an oxidation catalyst on each of these turbines to achieve VOC emissions of less than or equal to 2.0 ppmv @ 15% O_2 (3-hour average) during all operating modes. Therefore, BACT for VOC emissions during steady state operation and startup and shutdown periods is satisfied and no further discussion is required.

IV. Steady State and Startup/Shutdown PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.6 identifies achieved in practice BACT as the following:

- Air inlet filter, lube oil vent coalescer, and either PUC-regulated natural gas, LPG, or non-PUC regulated natural gas with < 0.75 grains S/ 100 dscf

SJVAPCD BACT Clearinghouse Guideline 3.4.6 does not identify any technologically feasible BACT control alternatives for PM_{10} emissions.

SJVAPCD BACT Clearinghouse Guideline 3.4.6 does not identify any alternate basic equipment BACT control alternatives for PM_{10} emissions.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Air inlet filter, lube oil vent coalescer, and either PUC-regulated natural gas, LPG, or non-PUC regulated natural gas with < 0.75 grains S/ 100 dscf.

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 with a sulfur content of no greater than 0.24 grains/100 dscf. 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, LPG, or non-PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf. The facility is proposing to use an air inlet cooler/filter, lube oil vent coalescer and PUC-regulated natural gas fuel with a sulfur content of no greater than 0.24 grains/100 dscf during all operating modes. Therefore, BACT for PM_{10} emissions during steady state operation and startup and shutdown periods is satisfied and no further discussion is required.

V. Steady State and Startup/Shutdown SO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.6 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel, LPG, or non-PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf, or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.6 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.6 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC-regulated natural gas fuel, LPG, or non-PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf, or equal.

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use PUC-regulated natural gas fuel with a sulfur content of no greater than 0.24 grains/100 dscf. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of PUC-regulated natural gas fuel, LPG, or non-PUC-regulated natural gas fuel with < 0.75 grains S/100 dscf. The facility has proposed to fire each of these turbines on PUC-regulated natural gas fuel with a sulfur content of no greater than 0.24 grains/100 dscf during all operating modes. Therefore, BACT for SO_X emissions during steady state operation and startup and shutdown periods is satisfied and no further discussion is required.

ATTACHMENT I

Emergency IC Engine Top Down BACT Analysis (C-4140-3-0)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

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

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any technologically feasible BACT control alternatives for NO_X emissions.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives for NO_X emissions.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. Certified NO_X emissions of 6.9 grams/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 to install a Tier 3 certified diesel fired emergency IC engine with certified NO_X emissions of 2.661 grams/bhp-hr or less. This is the only 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 a diesel fired emergency IC engine with certified NO_X emissions of less than or equal to 6.9 grams/bhp-hr. The facility has proposed to use a Tier 3 certified diesel fired emergency IC engine with NO_X emissions of less than or equal to 2.661 grams/bhp-hr. Therefore, BACT for NO_X emissions 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 Laboratories (UL) certification]

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Oxidation Catalyst

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives for VOC emissions.

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. Oxidation Catalyst
2. Positive Crankcase Ventilation (unless it voids the UL certification)

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.

However, this engine has been UL Certified, and the UL certification does not include a catalytic oxidation system, and the addition of a catalytic oxidation system would void the UL certification, which is required for firewater pump engines. Therefore, the catalytic oxidation system option will not be required.

The applicant is proposing a positive crankcase ventilation system. This is the next highest ranking control technology alternative in the ranking list from Step 3 and it has been achieved in practice. Therefore, per SJVUAPCD BACT policy, a cost effectiveness analysis is not required.

Step 5 - Select BACT

BACT for VOC emissions from this emergency diesel IC engine powering a firewater pump is having positive crankcase ventilation. The applicant has proposed to install a 460 bhp emergency diesel IC engine powering a firewater pump with positive crankcase ventilation. Therefore BACT for VOC emissions is satisfied.

ATTACHMENT J

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Air Pollution Control District
Risk Management Review

To:	Dustin Brown – Permit Services
From:	Leland Villalvazo – Technical Services
Date:	February 9, 2009
Facility Name:	GWF Hanford
Location	4300 Railroad Avenue
Application #(s)	C-4140-1-5,2-5,3-0
Project #:	C-1083169

A. RMR SUMMARY

RMR Summary				
Categories	Unit 1-5, 2-5	Unit 3-0	Project Totals	Facility Totals
Prioritization Score	NA[1]	0.5	0.5	0.5
Acute Hazard Index	NA[1]	NA	NA	NA
Chronic Hazard Index	NA[1]	NA	NA	NA
Maximum Individual Cancer Risk (10^{-6})	NA[1]	NA	NA	NA
T-BACT Required?	No	Yes		
Special Permit Conditions?	No	Yes		

1 There is no increase in fuel usage from the previous RMR perform. Therefore no increase in risk

Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

Unit # 1-5, 2-5

No special conditions are required.

Unit # 3-0

1. Modified {1901} The PM10 emissions rate shall not exceed **0.078** g/hp-hr based on US EPA certification using ISO 8178 test procedure. [District Rule 2201]
2. {1902} The sulfur content of the diesel fuel used shall not exceed 0.05% by weight. [District Rule 2201] N
3. {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 50 hours per year. [District NSR Rule and District Rule 4701] N

B. RMR REPORT

I. Project Description

Technical Services received a request on January 15, 2009, to perform an Ambient Air Quality Analysis and a Risk Management Review for modification of two 45MW turbines and a new 460 HP diesel fired IC engine.

II. Analysis

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 40.5 lb/hr CO, 52.0 lb/hr NOx, 0.33 lb/hr SOx, and 2.26 lb/hr PM_{10}, values based on worst case hourly emissions. The engineer supplied the maximum fuel rate for the equipment used during the analysis.

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[1]	Pass[1]

*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 prioritization score is less than 1.0. **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 applicant/project engineer
C. Toxic emissions summary
D. Prioritization score

ATTACHMENT K

GWF Power Systems Statewide Compliance Certification

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

4300 RAILROAD AVE., PITTSBURG, CALIFORNIA 94565 · TEL. (925) 431-1444 · FAX (925) 431-0515

ATTACHMENT L

GWF Hanford Existing Turbine Baseline Fuel Usage Records

Hanford Energy Park Peaker
Historical Fuel Usage - MCF gas

	2005		2006		2007		2008	
	Unit 21A	Unit 21B	Unit 21A	Unit 21B	Unit 21A	Unit 21B	Unit 21A	Unit 21B
January	1,665	1,641	7,162	6,636	90,847	87,434	14,864	16,016
February	1,087	1,091	6	6	522	528	1,962	2,162
March	730	429	27	27	277	258	3,684	3,219
April	1,789	1,315	721	2,622	4,801	929	4,819	954
May	2,088	1,576	5,615	5,372	189	22	8,379	13,724
June	5,661	5,108	19,666	19,826	15,948	18,007	18,459	20,003
July	99,763	96,209	52,398	55,906	13,359	14,345	15,549	13,951
August	30,597	32,259	6,121	5,340	38,849	41,300	18,292	19,212
September	2,050	1,397	1,452	1,214	2,171	2,269	31,402	33,496
October	3,021	2,493	1,577	1,314	589	698	35,801	39,876
November	5,665	5,462	5,088	5,042	8,146	8,609	24,431	26,468
December	8,550	7,799	433	271	4,796	5,388	32,569	35,279
Annual Total	162,667	156,778	100,264	103,574	180,494	179,786	210,212	224,362

Henrietta Peake Plant
Historical Fuel Usage - MCF gas

	2005		2006		2007		2008	
	Unit 22A	Unit 22B	Unit 22A	Unit 22B	Unit 22A	Unit 22B	Unit 22A	Unit 22B
January	1,738	1,751	1,604	1,669	6,279	5,466	13,350	12,913
February	3,031	2,181	14	14	1,591	1,607	5,236	3,515
March		2,589	1	1	6,929	7,130	12,212	8,730
April	2,419	1,754	767	1,238	5,781	5,294	8,207	7,977
May	2,120	2,646	2,036	2,124	1,450	117	885	1,698
June	6,087	6,068	20,346	20,159	8,621	8,660	21,212	21,085
July	26,846	30,015	42,836	42,489	10,426	8,841	16,936	15,644
August	7,793	7,916	5,366	5,239	38,320	37,917	18,661	18,047
September	2,176	1,853	1,200	1,203	2,152	1,876	29,438	28,885
October	956	863	4,957	6,969	1,728	1,629	43,001	42,792
November	4,615	3,315	11,231	8,421	10,779	9,739	33,525	33,124
December	5,148	3,698	1,142	723	10,622	9,978	30,112	30,956
Annual Total	62,929	64,650	91,500	90,248	104,677	98,255	232,775	225,366