San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

JUL 30 2013

Lyle Schlyer
Pixley Cogen Partners
P.O. Box 891
Pixley, CA 93256

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: S-6534
Project Number: S-1131975

Dear Mr. Schlyer:

Enclosed for your review and comment is the District's analysis of Pixley Cogen Partners's application for an Authority to Construct for installation of one 5.67 MW (ISO rated) combined heat and power (CHP) cogeneration system consisting of one 67.65 MMBtu/hr natural gas-fired Solar Model Taurus 60 (T-60) turbine and one 106.4 natural gas/biogas-fired MMBtu/hr Rentech duct burner with Rentech selective catalytic reduction (SCR) and CO catalyst and Heat Recovery Steam Generator (HRSG), at 11222 Road 120 in Pixley, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Stanley Tom of Permit Services at (559) 230- 5900.

Sincerely,

David Warner
Director of Permit Services

DW:st

Enclosures

cc: Mike Tollstrup, CARB (w/ enclosure) via email

Seyed Sadredin
Executive Director/Air Pollution Control Officer

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NOTICE OF PRELIMINARY DECISION
FOR THE PROPOSED ISSUANCE OF
AN AUTHORITY TO CONSTRUCT

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the proposed issuance of Authority to Construct to Pixley Cogen Partners for installation of one 5.67 MW (ISO rated) combined heat and power (CHP) cogeneration system consisting of one 67.65 MMBtu/hr natural gas-fired Solar Model Taurus 60 (T-60) turbine and one 106.4 natural gas/biogas-fired MMBtu/hr Rentech duct burner with Rentech selective catalytic reduction (SCR) and CO catalyst and Heat Recovery Steam Generator (HRSG), at 11222 Road 120 in Pixley, CA.

The analysis of the regulatory basis for this proposed action, Project #S-1131975, is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and at any District office. For additional information, please contact the District at (559) 230-6000. Written comments on this project must be submitted by September 5, 2013 to **DAVID WARNER, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review
Cogeneration System Consisting of One Natural Gas-Fired Turbine and Duct Burner

Facility Name:	Pixley Cogen Partners	Date:	July 26, 2013
Mailing Address:	P.O. Box 891 Pixley, CA 93256	Engineer:	Stanley Tom
		Lead Engineer:	Joven Refuerzo
Contact Person:	Lyle Schlyer		
Telephone:	(559) 757-3850 x2102		
E-Mail:	lschlyer@calgren.com		
Application No:	S-6534-3-4 and '5-0		
Project No:	S-1131975		
Deemed Complete:	May 29, 2013		

I. Proposal

Pixley Cogen Partners (PCP) has requested Authority to Construct (ATC) permits for the installation of one 5.67 MW (ISO rated) combined heat and power (CHP) cogeneration system consisting of one 67.65 MMBtu/hr natural gas-fired Solar Model Taurus 60 (T-60) turbine and one 106.4 natural gas/biogas-fired MMBtu/hr Rentech duct burner with Rentech selective catalytic reduction (SCR) and CO catalyst and Heat Recovery Steam Generator (HRSG). The ratings are based upon the higher heating value of natural gas.

The facility currently operates one 5.432 MW electric power generation and steam production system consisting of one 67.1 MMBtu/hr natural gas-fired Solar Model Taurus 65 (T-65) turbine and one 106.4 MMBtu/hr natural gas-fired duct burner listed on permit S-6534-3 (see Attachment A). The proposed duct burner in this project and the duct burner listed on permit S-6534-3 will have a combined heat input limit of 106.4 MMBtu/hr based on the higher heating value of natural gas.

The proposed turbine will be fired solely on natural gas. The duct burner will be fired up to a 50% biogas/natural gas blend.

This facility will not be a major source for any pollutant.

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 2201	New and Modified Stationary Source Review Rule (4/21/11)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (6/21/01)

Rule 2540	Acid Rain Program (11/13/97)
Rule 4001	New Source Performance Standards (4/14/99)
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/20/04)
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 4305	Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306	Boilers, Steam Generators and Process Heaters – Phase 3 (10/16/08)
Rule 4320	Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (10/16/08)
Rule 4703	Stationary Gas Turbines (9/20/07)
Rule 4801	Sulfur Compounds (12/17/92)
CH&SC 41700	Health Risk Assessment
CH&SC 42301.6	School Notice

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The facility is located at 11222 Road 120 in Pixley, CA. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

The proposed equipment will be used to generate electricity and steam which will be sold to the nearby ethanol plant, grain handling facility, and other nearby businesses. The combined cycle generator set is equipped with a waste heat recovery boiler.

V. Equipment Listing

<u>Pre-Project Equipment Description</u>

Permit #	Pre-Project Equipment Description
S-6534-3-4	5.432 MW ELECTRIC POWER GENERATION SYSTEM (COMBINED CYCLE CONFIGURATION) CONSISTING OF A 67.1 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) SOLAR MODEL #TAURUS 65-8401S NATURAL GAS-FIRED COMBUSTION TURBINE WITH A 106.4 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) NATURAL GAS-FIRED DUCT BURNER, ALL SERVED BY A CO CATALYST AND A SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION

Proposed Modification

Permit #	ATC Equipment Description
S-6534-3-4	MODIFICATION OF 5.432 MW ELECTRIC POWER GENERATION SYSTEM (COMBINED CYCLE CONFIGURATION) CONSISTING OF A 67.1 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) SOLAR MODEL #TAURUS 65-8401S NATURAL GAS-FIRED COMBUSTION TURBINE WITH A 106.4 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) NATURAL GAS-FIRED DUCT BURNER, ALL SERVED BY A CO CATALYST AND A SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION: LIMIT COMBINED HEAT INPUT FOR DUCT BURNERS LISTED ON PERMITS S-6534-3 AND '5 TO 106.4 MMBTU/HR
S-6534-5-0	5.67 MW ELECTRIC POWER GENERATION SYSTEM (COMBINED CYCLE CONFIGURATION), CONSISTING OF A 67.65 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) SOLAR MODEL #TAURUS60-7901S NATURAL GAS-FIRED COMBUSTION TURBINE WITH A 106.4 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) NATURAL GAS/BIOGAS-FIRED DUCT BURNER, ALL SERVED BY A CO CATALYST AND A RENTECH SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION AND A HEAT RECOVERY STEAM GENERATOR

Post-Project Equipment Description

Permit #	Post-Project Equipment Description
S-6534-3-4	5.432 MW ELECTRIC POWER GENERATION SYSTEM (COMBINED CYCLE CONFIGURATION) CONSISTING OF A 67.1 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) SOLAR MODEL #TAURUS 65-8401S NATURAL GAS-FIRED COMBUSTION TURBINE WITH A 106.4 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) NATURAL GAS-FIRED DUCT BURNER, ALL SERVED BY A CO CATALYST AND A SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION
S-6534-5-0	5.67 MW ELECTRIC POWER GENERATION SYSTEM (COMBINED CYCLE CONFIGURATION), CONSISTING OF A 67.65 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) SOLAR MODEL #TAURUS60-7901S NATURAL GAS-FIRED COMBUSTION TURBINE WITH A 106.4 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) NATURAL GAS/BIOGAS-FIRED DUCT BURNER, ALL SERVED BY A CO CATALYST AND A RENTECH SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION AND A HEAT RECOVERY STEAM GENERATOR

VI. Emission Control Technology Evaluation

Emissions from natural gas-fired turbines include NOx, SOx, PM10, CO, and VOC.

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

Thermal NOx is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NOx, a form of thermal NOx, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NOx.

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

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

Selective Catalytic Reduction (SCR)

For control of NOx, the cogeneration unit will utilize selective catalytic reductioni (SCR) with anhydrous ammonia injection.

SCR systems selectively reduce NOx emissions by injecting ammonia (NH3) into the exhaust gas stream upstream of a catalyst. NOx, NH3, and O2 react on the surface of the catalyst to form molecular nitrogen (N2) and H2O. SCR is capable of over 90 percent NOx reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentaoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 ^{o}F. Exhaust gas temperatures greater than the upper limit (750 ^{o}F) will cause NOx and NH3 to pass through the catalyst unreacted.

Oxidation Catalyst (CO Catalyst)

For control of CO, the cogeneration unit will utilize a CO catalyst.

CO emissions result from incomplete combustion, CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, as gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions. CO catalyst is also being used to reduce VOC and organic HAP emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO2) and water as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement of introducing reactants. The performance of the oxidation catalyst streams on combustion turbines results in 90+ percent control of CO and above 85 to 90 percent control of formaldehyde. Similar emission reductions are expected for other HAP pollutants.

VII. General Calculations

A. Assumptions

- Operation schedule = 24 hr/day and 365 days/year (per applicant)
- All calculations and physical constants used are corrected to Standard Conditions as defined in District Rule 1020 Section 3.47

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- The turbine will be started up a maximum of 2 times per day and shutdown a maximum of 2 times per day. (per current PTO)
- The turbine will be started up a maximum of 48 times per year and shutdown a maximum of 48 times per year. (per current PTO)
- Startup emissions and shutdown emissions for the Taurus 65 turbine are approximately 1.3 times greater than the startup and shutdown emissions of a Taurus 60 turbine (per project S-1082653)
- A full startup event takes 30 minutes, of which 9 minutes is for the turbine to startup and the remaining 21 minutes is for the SCR system and the CO Catalyst to begin operating at full efficiency. (per applicant)
- Shutdown of the turbine takes 10 minutes. (per manufacturer)
- The duct burner is not fired during the 30-minute startup period or during shutdown, but operates during all other operating modes.
- It is assumed that PM_{10}, SOx, and NH_3 emissions are unaffected during startup and shutdown of the turbine and control devices.

- The higher heating value of the natural gas used is 1000 Btu/scf and the lower heating value of the natural gas used is 909 Btu/scf. The heat input ratings for the equipment, based on the higher heating value, are:

Equipment	HHV/LHV	Heat Input Rating (LHV)	Heat Input Rating (HHV)
Turbine	1.1	61.0	67.1
Duct Burner	1.1	96.7	106.4
Total	1.1	157.7	173.5

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- The duct burner is not fired during the 30-minute turbine startup period or during shutdown, but does operate during all other operating modes
- SOx, PM10, and NH3 emissions are unaffected during startup and shutdown periods
- Natural gas higher heating value = 1,000 Btu/scf
- Natural gas F-factor (adjusted to 60 °F) = 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- PUC-regulated natural gas sulfur concentration = 1.0 gr-S/100 scf or 0.00285 lb-SO2/MMBtu (District Policy APR 1720)
- Non-PUC-regulated natural gas sulfur concentration = 0.75 gr-S/100 scf (per applicant)
- Emissions during commissioning of the turbine are based on information provided by Solar Turbines Inc. and the applicant. During commissioning, the catalysts do not reach their recommended operating temperature during testing and are ineffective at controlling emissions during commissioning.
- The two duct burners listed on permits S-6534-3 and S-6534-5 will share a combined heat input limit of 106.4 MMBtu/hr based on the higher heating value of natural gas (per applicant)

The applicant has proposed the following startup and shutdown provisions.

Turbine Startup and Shutdown Daily Events			
Daily # of Startups	Startup Duration (minutes/event)	Daily # of Shutdowns	Shutdown Duration (minutes/event)
2	30	2	10

Turbine Startup and Shutdown Annual Events			
Annual # of Startups	Startup Duration (minutes/event)	Annual # of Shutdowns	Shutdown Duration (minutes/event)
12	30	12	10

B. Emission Factors

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The following table shows the emission factors for full-load, steady state operation of the turbine with the emissions control systems operating at full efficiency. The following factors are also applicable to the 150 MMBtu/hr duct burner.

Pollutant	100% Load w/Emissions Controls
NO_x	2.5 ppmvd @ 15% O_2
VOC	2.0 ppmvd @ 15% O_2
CO	6.0 ppmvd @ 15% O_2
PM_{10}	0.016 lb/MMBtu
SO_x	0.00285 lb/MMBtu
NH_3	10.0 ppmvd @ 15% O_2

The following NOx, CO, and VOC emissions occur during startup and shutdown of the Solar Turbines Inc. Taurus 65 turbine.

Pollutant	Taurus 65 Startup Emissions	Taurus 65 Shutdown Emissions
NO_x	0.7 lb/startup (9 minutes)	0.5 lb/shutdown (10 minutes)
VOC	1.3 lb/startup (9 minutes)	0.5 lb/shutdown (10 minutes)
CO	16.3 lb/startup (9 minutes)	5.6 lb/shutdown (10 minutes)

After the 9-minute startup time for the turbine, it takes another 21 minutes for the emissions control equipment to operate at full efficiency. The following emissions factors, for NOx, VOC, and CO emissions will be used to calculate worst-case emissions during this 21-minute period.

Pollutant	100% Load w/o Emissions Controls
NO_x	25 ppmvd @ 15% O_2
VOC	25 ppmvd @ 15% O_2
CO	50 ppmvd @ 15% O_2

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Startup

Startup Emissions (First 9 minute duration)*			
Pollutant	NO_X (lb/event)	CO (lb/event)	VOC (lb/event)
Mass Emission Rate	0.8	78.5	1.3

* Per turbine manufacturer Solar Turbines at which time the SCR will not operate at full efficiency. VOC emissions taken from T-65 turbine listed on permit S-6534-3 which has slightly higher emissions than the T-60 turbine in this project.

Startup Emissions (Final 21 minute duration)*		
Pollutant	(ppmv @ 15% O2)	(lb/MMBtu)
NO_X	25.0	0.0907
CO	50.0	0.110
VOC	25.0	0.0315

* Per turbine manufacturer Solar Turbines at which time the SCR will not operate at full efficiency. Emissions taken from T-65 turbine listed on permit S-6534-3.

Shutdown

Shutdown Emissions (10 minute duration)*			
Pollutant	NO_X (lb/event)	CO (lb/event)	VOC (lb/event)
Mass Emission Rate	0.4	34.7	0.5

* Per turbine manufacturer Solar Turbines at which time the SCR will not operate at full efficiency. VOC emissions taken from T-65 turbine listed on permit S-6534-3 which has slightly higher emissions than the T-60 turbine in this project.

Steady State

The following emission factors are after the CO catalyst and SCR catalyst based on 100% load.

Turbine			
Pollutant	ppmvd @ 15% O2	lb/MMBtu	Source
NO_X	2.5	0.00907	BACT Guideline 3.4.3
SO_X	-	0.00285	BACT Guideline 3.4.3
PM_{10}	-	0.013	Solar Turbine T-65 Source Test dated August 2009 times 1.91 compliance margin
CO	6.0	0.0132	BACT Guideline 3.4.3
VOC	2.0	0.00252	BACT Guideline 3.4.3
NH_3	5.0	0.0067	Applicant Proposal

Duct Burner			
Pollutant	ppmvd @ 15% O2	lb/MMBtu	Source
NO_X	2.5	0.00907	BACT Guideline 3.4.3
SO_X	-	0.00214	BACT Guideline 3.4.3
PM_{10}	-	0.013	Solar Turbine T-65 Source Test dated August 2009 times 1.91 compliance margin
CO	6.0	0.0132	BACT Guideline 3.4.3
VOC	2.0	0.00252	BACT Guideline 3.4.3
NH_3	5.0	0.0067	Applicant Proposal

C. Calculations

1. Pre-Project Potential to Emit (PE1)

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Turbine Daily Emissions

Since the startup and shutdown turbine emissions are greater than the emissions during normal operation of the turbine at full-load, the maximum daily emissions from the turbine occur when the turbine is started two times and shut down two times (maximum per applicant). Therefore, the startup and shutdown emissions must be calculated to determine the maximum daily emissions from the turbine.

Startup Emissions

A startup event takes a total of 30 minutes. Solar Turbines Inc. has provided the following emissions estimates for the first 9 minutes of startup of the turbine.

Pollutant	Taurus 65 Startup Emissions
NO_x	0.7 lb/startup (9 minutes)
VOC	1.3 lb/startup (9 minutes)
CO	16.3 lb/startup (9 minutes)

The following formula and the emissions factors in the table below will be used to determine the emissions for the remaining 21 minutes of startup, during the time the emissions control systems are not operating at their full efficiency. Worst-case emissions for this period of operation are based on the turbine operating at 100% load.

$$PE_{NOx,VOC,CO} = \frac{EF(ppmvd)\times F-Factor\left(\frac{dscf}{MMBtu}\right)\times MW\left(\frac{lb}{lb-mol}\right)\times\frac{21\min}{60\min}\times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right)\times 10^6}$$

Pollutant	100% Load w/o Emissions Controls
NO_x	25 ppmvd @ 15% O_2
VOC	25 ppmvd @ 15% O_2
CO	50 ppmvd @ 15% O_2

$$PE_{NOx} = \frac{25(ppmvd)\times 8578\left(\frac{dscf}{MMBtu}\right)\times 46\left(\frac{lb}{lb-mol}\right)\times\frac{21\min}{60\min}\times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right)\times 10^6} = 2.2 lb-NOx$$

$$PE_{VOC} = \frac{25(ppmvd)\times 8578\left(\frac{dscf}{MMBtu}\right)\times 16\left(\frac{lb}{lb-mol}\right)\times\frac{21\min}{60\min}\times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right)\times 10^6} = 0.8 lb-VOC$$

$$PE_{CO} = \frac{50(ppmvd)\times 8578\left(\frac{dscf}{MMBtu}\right)\times 28\left(\frac{lb}{lb-mol}\right)\times\frac{21\min}{60\min}\times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right)\times 10^6} = 2.6 lb-CO$$

Total NOx, VOC, and CO Startup Emissions per event						
Pollutant	Time Elapsed	Emissions	Time Elapsed	Emissions	Total Time Elapsed	Total Startup Emissions
NOx	9 min	0.7 lb	21 min	2.2	30 min	2.9 lb
VOC	9 min	1.3 lb	21 min	0.8	30 min	2.1 lb
CO	9 min	16.3 lb	21 min	2.6	30 min	18.9 lb

Shutdown Emissions

Solar Turbines Inc. provided the following emissions estimates for the shutdown of the turbine.

Pollutant	Taurus 65 Shutdown Emissions
NO_x	0.5 lb/shutdown (10 minutes)
VOC	0.5 lb/shutdown (10 minutes)
CO	5.6 lb/shutdown (10 minutes)

Total Daily Turbine NOx, CO, and VOC Emissions

There are a maximum of 2 startups and 2 shutdowns per day. The maximum daily emissions contribution from startup and shutdown of the turbine is shown below.

Total NOx, VOC and CO Startup Emissions per day from Turbine						
Pollutant	Startup Time Elapsed (2 events)	Startup Emissions (2 events)	Shutdown Time Elapsed (2 events)	Shutdown Emissions (2 events)	Total Time Elapsed	Total Startup and Shutdown Emissions
NOx	60 min	5.8 lb	20 min	1.0 lb	80 min	6.8 lb
VOC	60 min	4.2 lb	20 min	1.0 lb	80 min	5.2 lb
CO	60 min	37.8 lb	20 min	11.2 lb	80 min	49.0 lb

There are 1440 minutes per day and the turbine was assumed to be in startup or shutdown for 80 of the 1440 minutes. The NOx, CO, and VOC emissions from the remaining 1360 minutes are calculated using the formula and table below.

$$PE_{NOx,VOC,CO} = \frac{EF(ppmvd) \times F-Factor\left(\frac{dscf}{MMBtu}\right) \times MW\left(\frac{lb}{lb-mol}\right) \times \frac{1360\text{min}}{60\text{min}} \times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6}$$

Pollutant	100% Load w/Emissions Controls
NO_x	2.5 ppmvd @ 15% O_2
VOC	2.0 ppmvd @ 15% O_2
CO	6.0 ppmvd @ 15% O_2

$$PE_{NOx} = \frac{2.5(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 46\left(\frac{lb}{lb-mol}\right) \times \frac{1360\text{min}}{60\text{min}} \times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 14.0 lb-NOx$$

$$PE_{VOC} = \frac{2.0(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 16\left(\frac{lb}{lb-mol}\right) \times \frac{1360\text{min}}{60\text{min}} \times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 3.9 lb-VOC$$

$$PE_{CO} = \frac{6(ppmvd)\times 8578\left(\frac{dscf}{MMBtu}\right)\times 28\left(\frac{lb}{lb-mol}\right)\times\frac{1360\min}{60\min}\times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right)\times 10^{6}} = 20.5 lb - CO$$

Total Daily NOx, VOC and CO Emissions from Turbine			
Pollutant	Startup and Shutdown Emissions	Normal Operation Emissions	Total Emissions
NOx	6.8 lb	14.0 lb	20.8 lb/day
VOC	5.2 lb	3.9 lb	9.1 lb/day
CO	49.0 lb	20.5 lb	69.5 lb/day

Turbine PM_{10}, SOx, and NH_3 emissions

PM10, SOx and NH_3 emissions are not affected by startup or shutdown. The maximum daily emissions, from this permit unit, are calculated below.

PE_{PM10} = 24 hours/day x 67.1 MMBtu/hr x EF_{PM10}
PE_{PM10} = 24 hours/day x 67.1 MMBtu/hr x 0.016 lb/MMBtu
PE_{PM10} = 25.7 lb/day

PE_{SOx} = 24 hours/day x 67.1 MMBtu/hr x EF_{SOx}
PE_{SOx} = 24 hours/day x 67.1 MMBtu/hr x 0.00285 lb/MMBtu
PE_{SOx} = 4.6 lb/day

$$PE_{NH3} = \frac{(ppmvd)\times 8578\left(\frac{dscf}{MMBtu}\right)\times 17\left(\frac{lb}{lb-mol}\right)\times 24hr\times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right)\times 10^{6}}$$

$$PE_{NH3} = \frac{10(ppmvd)\times 8578\left(\frac{dscf}{MMBtu}\right)\times 17\left(\frac{lb}{lb-mol}\right)\times 24hr\times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right)\times 10^{6}} = 21.9\frac{lb}{day}$$

Total Daily Turbine Emissions

Total Daily Turbine Emissions (lb/day)					
NOx	VOC	CO	PM10	SOx	NH_3
20.8	9.1	69.5	25.7	4.6	21.9

Duct Burner Daily Emissions

Since the duct burner is assumed to only operate during normal operating modes where the catalysts are at minimum operating temperature, the duct burner daily emissions will be calculated assuming 24 hours of operation of the duct burners at maximum capacity and using the emissions factors in the following table:

Pollutant	100% Load w/Emissions Controls
NO_x	2.5 ppmvd @ 15% O_2
VOC	2.0 ppmvd @ 15% O_2
CO	6.0 ppmvd @ 15% O_2
PM_{10}	0.016 lb/MMBtu
SO_x	0.00285 lb/MMBtu
NH_3	10.0 ppmvd @ 15% O_2

$$PE_{NOx,VOC,CO} = \frac{EF(ppmvd) \times F-Factor\left(\frac{dscf}{MMBtu}\right) \times MW\left(\frac{lb}{lb-mol}\right) \times 24\frac{hr}{day} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6}$$

$$PE_{NOx} = \frac{2.5(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 46\left(\frac{lb}{lb-mol}\right) \times 24\frac{hr}{day} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 23.5\frac{lb-NOx}{day}$$

$$PE_{VOC} = \frac{2.0(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 16\left(\frac{lb}{lb-mol}\right) \times 24\frac{hr}{day} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 6.5\frac{lb-VOC}{day}$$

$$PE_{CO} = \frac{6(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 28\left(\frac{lb}{lb-mol}\right) \times 24\frac{hr}{day} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 34.3\frac{lb-CO}{day}$$

PE_{PM10} = 24 hours/day x 106.4 MMBtu/hr x EF_{PM10}
PE_{PM10} = 24 hours/day x 106.4 MMBtu/hr x 0.016 lb/MMBtu
PE_{PM10} = 40.8 lb/day

PE_{SOx} = 24 hours/day x 106.4 MMBtu/hr x EF_{SOx}
PE_{SOx} = 24 hours/day x 106.4 MMBtu/hr x 0.00285 lb/MMBtu
PE_{SOx} = 7.3 lb/day

$$PE_{NH3} = \frac{(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 17\left(\frac{lb}{lb-mol}\right) \times 24\frac{hr}{day} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6}$$

$$PE_{NH3} = \frac{10(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 17\left(\frac{lb}{lb-mol}\right) \times 24\frac{hr}{day} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 34.7\frac{lb-NH_3}{day}$$

Total Daily Duct Burner (lb/day)					
NOx	**VOC**	**CO**	**PM_{10}**	**SOx**	**NH_3**
23.5	6.5	34.3	40.8	7.3	34.7

Total Daily Emissions from Permit Unit S-6534-3-4						
Emissions Unit	**NOx**	**SOx**	**PM_{10}**	**CO**	**VOC**	**NH_3**
Turbine (lb/day)	20.8	4.6	25.7	69.5	9.1	21.9
Duct Burner (lb/day)	23.5	7.3	40.8	34.3	6.5	34.7
Total PE1 (lb/day)	44.3	11.9	66.5	103.8	15.6	56.6

Turbine Annual Emissions

NOx, CO, and VOC:

There are a maximum 48 startups and 48 shutdowns per year. Thus, the annual emissions from startup and shutdown of the turbine are:

Total NOx, VOC and CO Startup and Shutdown Emissions per year:						
Pollutant	Startup Time Elapsed (48 events)	Startup Emissions (48 events)	Shutdown Time Elapsed (48 events)	Shutdown Emissions (48 events)	Total Time Elapsed	Total Startup and Shutdown Emissions
NOx	24 hr	139 lb	8 hr	24 lb	32 hr	163 lb/yr
VOC	24 hr	101 lb	8 hr	24 lb	32 hr	125 lb/yr
CO	24 hr	907 lb	8 hr	269 lb	32 hr	1,176 lb/yr

There are 8,760 hours in one year and the unit was assumed to be in startup or shutdown for 32 of those hours. The NOx, CO, and VOC emissions from the remaining 8,728 hours are calculated using the following formula.

$$PE_{NOx,VOC,CO} = \frac{EF(ppmvd) \times F-Factor\left(\frac{dscf}{MMBtu}\right) \times MW\left(\frac{lb}{lb-mol}\right) \times 8728hr \times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6}$$

Pollutant	EF 100% Load w/Emissions Controls
NO_x	2.5 ppmvd @ 15% O_2
VOC	2.0 ppmvd @ 15% O_2
CO	6.0 ppmvd @ 15% O_2

$$PE_{NOx} = \frac{2.5(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 46\left(\frac{lb}{lb-mol}\right) \times 8,728hr \times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 5,393 lb-NOx$$

$$PE_{VOC} = \frac{2(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 16\left(\frac{lb}{lb-mol}\right) \times 8728hr \times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 1,501 lb-VOC$$

$$PE_{CO} = \frac{6(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 28\left(\frac{lb}{lb-mol}\right) \times 8728hr \times 67.1\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 7,878 lb-CO$$

Total Annual NOx, VOC and CO Turbine Emissions			
Pollutant	Startup and Shutdown Emissions	Normal Operation Emissions	Total Emissions
NOx	163 lb/yr	5,393 lb/yr	5,556 lb/yr
VOC	125 lb/yr	1,501 lb/yr	1,626 lb/yr
CO	1,176 lb/yr	7,878 lb/yr	9,054 lb/yr

PM_{10}, SOx, NH_3:

PM_{10}, SOx and NH_3 emissions are not affected by startup or shutdown. Annual Emissions from these units are calculated below, using the daily emissions calculated earlier and assuming 365 days/year of operation.

PE_{PM10} = Daily PE_{PM10} (lb/day) x 365 days/year
PE_{PM10} = 25.7 lb/day x 365 days/year
PE_{PM10} = 9,381 lb/year

PE_{SOx} = Daily PE_{SOx} (lb/day) x 365 days/year
PE_{SOx} = 4.6 lb/day x 365 days/year
PE_{SOx} = 1,679 lb/year

PE_{NH3} = Daily PE_{NH3} (lb/day) x 365 days/year
PE_{NH3} = 21.9 lb/day x 365 days/year
PE_{NH3} = 7,994 lb/year

Total Annual Turbine Emissions (lb/year)					
NOx	**VOC**	**CO**	**PM_{10}**	**SOx**	**NH_3**
5,556	1,626	9,054	9,381	1,679	7,994

Duct Burner Annual Emissions

Since the duct burner is assumed to only operate during normal operating modes where the catalysts are at temperature. The duct burner daily emissions will be calculated assuming 8760 hours of operation of the duct burners at maximum capacity and using the emissions factors in the following table:

Pollutant	100% Load w/Emissions Controls
NO_x	2.5 ppmvd @ 15% O_2
VOC	2.0 ppmvd @ 15% O_2
CO	6.0 ppmvd @ 15% O_2
PM_{10}	0.012 lb/MMBtu
SO_x	0.00285 lb/MMBtu
NH_3	10.0 ppmvd @ 15% O_2

$$PE_{NOx,VOC,CO} = \frac{EF(ppmvd) \times F-Factor\left(\frac{dscf}{MMBtu}\right) \times MW\left(\frac{lb}{lb-mol}\right) \times 8760\frac{hr}{year} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6}$$

$$PE_{NOx} = \frac{2.5(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 46\left(\frac{lb}{lb-mol}\right) \times 8760\frac{hr}{year} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 8,582\frac{lb-NOx}{year}$$

$$PE_{VOC} = \frac{2.0(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 16\left(\frac{lb}{lb-mol}\right) \times 8760\frac{hr}{year} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 2,388\frac{lb-VOC}{year}$$

$$PE_{CO} = \frac{6(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 28\left(\frac{lb}{lb-mol}\right) \times 8760\frac{hr}{year} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 12{,}538\frac{lb-CO}{year}$$

PE_{PM10} = 8,760 hours/year x 106.4 MMBtu/hr x EF_{PM10}
PE_{PM10} = 8,760 hours/year x 106.4 MMBtu/hr x 0.016 lb-PM10/MMBtu
PE_{PM10} = 14,913 lb-PM10/year

PE_{SOx} = 8,760 hours/year x 106.4 MMBtu/hr x EF_{SOx}
PE_{SOx} = 8,760 hours/year x 106.4 MMBtu/hr x 0.00285 lb-SOx/MMBtu
PE_{SOx} = 2,656 lb-SOx/year

$$PE_{NH3} = \frac{(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 17\left(\frac{lb}{lb-mol}\right) \times 8{,}760\frac{hr}{year} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6}$$

$$PE_{NH3} = \frac{10(ppmvd) \times 8578\left(\frac{dscf}{MMBtu}\right) \times 17\left(\frac{lb}{lb-mol}\right) \times 8760\frac{hr}{year} \times 106.4\left(\frac{MMBtu}{hr}\right)\left(\frac{20.9}{20.9-15}\right)}{379.5\left(\frac{dscf}{lb-mol}\right) \times 10^6} = 12{,}687\frac{lb-NH_3}{year}$$

Total Annual Duct Burner Emissions (lb/year)					
NOx	VOC	CO	PM_{10}	SOx	NH_3
8,582	2,388	12,538	14,913	2,656	12,687

The total annual emissions from the turbine and duct burner are shown in the table below. However, the applicant has requested to limit annual CO emissions to 19,999 lb-CO/year and keep annual records of CO emissions. Therefore, emissions from the turbine and duct burner will be adjusted accordingly.

Total Annual Emissions from Permit Unit S-6534-3-4						
Emissions Unit	NOx	SOx	PM_{10}	CO	VOC	NH_3
Turbine (lb/year)	5,556	1,679	9,381	9,054	1,626	7,994
Duct Burner (lb/year)	8,582	2,656	14,913	12,538	2,388	12,687
Total PE1 (lb/year)	14,138	4,335	19,999[1]	19,999[1]	4,014	19,999[1]

<u>S-6534-5-0</u>

Since this is a new emissions unit, PE1 = 0 for all pollutants.

[1] The applicant has requested to limit CO, PM10, and NH_3 emissions to less than 20,000 lb/year. The applicant will keep a record of annual CO, PM10, and NH_3 emissions to ensure compliance with these limits.

2. Post Project Potential to Emit (PE2)

S-6534-3-4

There are no proposed changes in emissions for this permit unit. Therefore, PE2 = PE1.

S-6534-5-0

Startup Emissions

Daily Startup Emissions (First 9 minutes/event)								
NO_X	0.8	(lb/event)	x	2	(events/day)	=	1.6	(lb/day)
CO	78.5	(lb/event)	x	2	(events/day)	=	157.0	(lb/day)
VOC	1.3	(lb/event)	x	2	(events/day)	=	2.6	(lb/day)

Daily Startup Emissions (Final 21 minutes/event) – Turbine														
NO_X	0.0907	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	21/60	(hr/event)	x	2	(event/day)	=	4.3	(lb/day)
CO	0.110	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	21/60	(hr/event)	x	2	(event/day)	=	5.2	(lb/day)
VOC	0.0315	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	21/60	(hr/event)	x	2	(event/day)	=	1.5	(lb/day)

Total Daily Startup Emissions (30 minute duration/event)								
	First 9 minutes			Final 21 minutes			Total 30 minutes	
NO_X	1.6	(lb/day)	+	4.3	(lb/day)	=	5.9	(lb/day)
CO	157.0	(lb/day)	+	5.2	(lb/day)	=	162.2	(lb/day)
VOC	2.6	(lb/day)	+	1.5	(lb/day)	=	4.1	(lb/day)

Annual Startup Emissions (First 9 minutes/event)								
NO_X	0.8	(lb/event)	x	12	(events/year)	=	10	(lb/year)
CO	78.5	(lb/event)	x	12	(events/year)	=	942	(lb/year)
VOC	1.3	(lb/event)	x	12	(events/year)	=	16	(lb/year)

Annual Startup Emissions (Final 21 minutes/event) – Turbine														
NO_X	0.0907	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	21/60	(hr/event)	x	12	(event/year)	=	26	(lb/year)
CO	0.110	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	21/60	(hr/event)	x	12	(event/year)	=	31	(lb/year)
VOC	0.0315	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	21/60	(hr/event)	x	12	(event/year)	=	9	(lb/year)

Total Annual Startup Emissions (30 minute duration/event)								
	First 9 minutes			Final 21 minutes			Total 30 minutes	
NO_X	10	(lb/year)	+	26	(lb/year)	=	36	(lb/year)
CO	942	(lb/year)	+	31	(lb/year)	=	973	(lb/year)
VOC	16	(lb/year)	+	9	(lb/year)	=	25	(lb/year)

Shutdown Emissions

Daily Shutdown Emissions (10 minute duration/event)								
NO_X	0.4	(lb/event)	x	2	(events/day)	=	0.8	(lb/day)
CO	34.7	(lb/event)	x	2	(events/day)	=	69.4	(lb/day)
VOC	0.5	(lb/event)	x	2	(events/day)	=	1.0	(lb/day)

Annual Shutdown Emissions (10 minute duration/event)								
NO_X	0.4	(lb/event)	x	12	(events/year)	=	5	(lb/year)
CO	34.7	(lb/event)	x	12	(events/year)	=	416	(lb/year)
VOC	0.5	(lb/event)	x	12	(events/year)	=	6	(lb/year)

Commissioning

It is assumed that the turbine does not fire properly at the end of the 9-minute startup period and the turbine is immediately shut down. Shutdown takes approximately 10 minutes.

Assume 3 startups (9 minutes per event) and 3 shutdowns (10 mintues per event) can occur in an hour (3 x 9 minutes + 3 x 10 minutes = 57 minutes) with a highly conservative time of 1 minute between startup and shutdowns.

Hourly Startup Commissioning Emissions (9 minute Startup Duration/event)								
NO_X	0.8	(lb/event)	x	3	(events/hr)	=	2.4	(lb/hr)
CO	78.5	(lb/event)	x	3	(events/hr)	=	235.5	(lb/hr)
VOC	1.3	(lb/event)	x	3	(events/hr)	=	3.9	(lb/hr)

Hourly Shutdown Commissioning Emissions (10 minute Shutdown Duration/event)								
NO_X	0.4	(lb/event)	x	3	(events/hr)	=	1.2	(lb/hr)
CO	34.7	(lb/event)	x	3	(events/hr)	=	104.1	(lb/hr)
VOC	0.5	(lb/event)	x	3	(events/hr)	=	1.5	(lb/hr)

The SOx and PM10 emissions during the commissioning period will be the same as during steady state operation.

Hourly Steady State Commissioning Emissions – Turbine								
NO_X	0.0907	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	6.14	(lb/hr)
SO_X	0.00285	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	0.19	(lb/hr)
PM_{10}	0.013	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	0.88	(lb/hr)
CO	0.110	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	7.44	(lb/hr)
VOC	0.0315	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	2.13	(lb/hr)
NH_3	0.0067	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	0.45	(lb/hr)

Total Hourly Commissioning Emissions (1 hour duration)											
	Startup			Shutdown			Steady State			Total	
NO_X	2.4	(lb/hr)	+	1.2	(lb/hr)	+	6.14	(lb/hr)	=	9.74	(lb/hr)
SO_X							0.19	(lb/hr)	=	0.19	(lb/hr)
PM_{10}							0.88	(lb/hr)	=	0.88	(lb/hr)
CO	235.5	(lb/hr)	+	104.1	(lb/hr)	+	7.44	(lb/hr)	=	347.04	(lb/hr)
VOC	3.9	(lb/hr)	+	1.5	(lb/hr)	+	2.13	(lb/hr)	=	7.53	(lb/hr)
NH_3							0.45	(lb/hr)	=	0.45	(lb/hr)

<u>**Turbine**</u>

a. Hourly Post-Project Potential to Emit (PE2)

Hourly Steady State Emissions – Turbine								
NO_X	0.00907	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	0.61	(lb/hour)
SO_X	0.00285	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	0.19	(lb/hour)
PM_{10}	0.013	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	0.88	(lb/hour)
CO	0.0132	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	0.89	(lb/hour)
VOC	0.00252	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	0.17	(lb/hour)
NH_3	0.0067	(lb/MMBtu)	x	67.65	(MMBtu/hr)	=	0.45	(lb/hour)

b. Daily Post-Project Potential to Emit (PE2)

The turbine is assumed to be in startup or shutdown for 80 minutes per day (2 startups/day x 30 min/startup + 2 shutdowns/day x 10 min/shutdown). The NOx, CO, and VOC emissions from the remaining 1,360 minutes/day (1,440 minutes/day – 80 minutes/day) are calculated in the table below.

PM10, SOx and NH3 emissions are not affected by startup or shutdown.

Daily Steady State Emissions – Turbine											
NO_X	0.00907	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	1360/60	(hr/day)	=	13.9	(lb/day)
SO_X	0.00285	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	1360/60	(hr/day)	=	4.4	(lb/day)
PM_{10}	0.013	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	1360/60	(hr/day)	=	19.9	(lb/day)
CO	0.0132	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	1360/60	(hr/day)	=	20.2	(lb/day)
VOC	0.00252	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	1360/60	(hr/day)	=	3.9	(lb/day)
NH_3	0.0067	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	1360/60	(hr/day)	=	10.3	(lb/day)

Total Daily Emissions – Turbine											
	Startup			Shutdown			Steady State			Total	
NO_X	5.9	(lb/day)	+	0.8	(lb/day)	+	13.9	(lb/day)	=	20.6	(lb/day)
SO_X	-	(lb/day)	+	-	(lb/day)	+	4.4	(lb/day)	=	4.4	(lb/day)
PM_{10}	-	(lb/day)	+	-	(lb/day)	+	19.9	(lb/day)	=	19.9	(lb/day)
CO	162.2	(lb/day)	+	69.4	(lb/day)	+	20.2	(lb/day)	=	251.8	(lb/day)
VOC	4.1	(lb/day)	+	1.0	(lb/day)	+	3.9	(lb/day)	=	45.9	(lb/day)
NH_3	-	(lb/day)	+	-	(lb/day)	+	10.3	(lb/day)	=	10.3	(lb/day)

c. Annual Post-Project Potential to Emit (PE2)

The turbine is assumed to be in startup or shutdown for 8 hours per year (12 startups/year x 30 min/startup + 12 shutdowns/year x 10 min/shutdown). The NOx, CO, and VOC emissions from the remaining 8,752 hours/year (8,760 hours/year – 8 hours/year) are calculated in the table below.

PM10, SOx and NH3 emissions are not affected by startup or shutdown.

Annual Steady State Emissions – Turbine											
NO_X	0.00907	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	8,752	(hr/year)	=	5,370	(lb/year)
SO_X	0.00285	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	8,760	(hr/year)	=	1,689	(lb/year)
PM_{10}	0.013	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	8,760	(hr/year)	=	7,704	(lb/year)
CO	0.0132	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	8,752	(hr/year)	=	7,815	(lb/year)
VOC	0.00252	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	8,752	(hr/year)	=	1,492	(lb/year)
NH_3	0.0067	(lb/MMBtu)	x	67.65	(MMBtu/hr)	x	8,760	(hr/year)	=	3,971	(lb/year)

Total Annual Emissions – Turbine												
	Startup			Shutdown			Steady State			Total	
NO_X	36	(lb/year)	+	5	(lb/year)	+	5,370	(lb/year)	=	5,411	(lb/year)
SO_X	-	(lb/year)	+	-	(lb/year)	+	1,689	(lb/year)	=	1,689	(lb/year)
PM_{10}	-	(lb/year)	+	-	(lb/year)	+	7,704	(lb/year)	=	7,704	(lb/year)
CO	973	(lb/year)	+	416	(lb/year)	+	7,815	(lb/year)	=	9,204	(lb/year)
VOC	25	(lb/year)	+	6	(lb/year)	+	1,492	(lb/year)	=	1,523	(lb/year)
NH_3	-	(lb/year)	+	-	(lb/year)	+	3,971	(lb/year)	=	3,971	(lb/year)

Duct Burner

The duct burner is assumed to only operate during normal operating modes where the catalysts are at full efficiency. The duct burner emissions will be calculated assuming 24 hours per day and 8,760 hours per year operation at maximum capacity.

The duct burner with the T-60 turbine in this project (listed on permit S-6534-5) will only be operated when the duct burner with the T-65 turbine (listed on permit S-6534-3) is not operated.

a. Hourly Post-Project Potential to Emit (PE2)

Hourly Steady State Emissions – Duct Burner								
NO_X	0.00907	(lb/MMBtu)	x	106.4	(MMBtu/hr)	=	0.97	(lb/hour)
SO_X	0.00214	(lb/MMBtu)	x	106.4	(MMBtu/hr)	=	0.23	(lb/hour)
PM_{10}	0.013	(lb/MMBtu)	x	106.4	(MMBtu/hr)	=	1.38	(lb/hour)
CO	0.0132	(lb/MMBtu)	x	106.4	(MMBtu/hr)	=	1.40	(lb/hour)
VOC	0.00252	(lb/MMBtu)	x	106.4	(MMBtu/hr)	=	0.27	(lb/hour)
NH_3	0.0067	(lb/MMBtu)	x	106.4	(MMBtu/hr)	=	0.71	(lb/hour)

b. Daily Post-Project Potential to Emit (PE2)

Daily Emissions – Duct Burner											
NO_X	0.00907	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	24	(hr/day)	=	23.2	(lb/day)
SO_X	0.00214	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	24	(hr/day)	=	5.5	(lb/day)
PM_{10}	0.013	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	24	(hr/day)	=	33.2	(lb/day)
CO	0.0132	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	24	(hr/day)	=	33.7	(lb/day)
VOC	0.00252	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	24	(hr/day)	=	6.4	(lb/day)
NH_3	0.0067	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	24	(hr/day)	=	17.1	(lb/day)

c. **Annual Post-Project Potential to Emit (PE2)**

Annual Emissions – Duct Burner											
NO_X	0.00907	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	8,760	(hr/year)	=	8,454	(lb/year)
SO_X	0.00214	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	8,760	(hr/year)	=	1,995	(lb/year)
PM_{10}	0.013	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	8,760	(hr/year)	=	12,117	(lb/year)
CO	0.0132	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	8,760	(hr/year)	=	12,303	(lb/year)
VOC	0.00252	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	8,760	(hr/year)	=	2,349	(lb/year)
NH_3	0.0067	(lb/MMBtu)	x	106.4	(MMBtu/hr)	x	8,760	(hr/year)	=	6,245	(lb/year)

Permit Unit S-6534-5-0

a. **Hourly Post-Project Potential to Emit (PE2)**

Total Hourly Emissions								
	Turbine			Duct Burner			Total	
NO_X	0.61	(lb/hour)	+	0.97	(lb/hour)	=	1.58	(lb/hour)
SO_X	0.19	(lb/hour)	+	0.23	(lb/hour)	=	0.42	(lb/hour)
PM_{10}	0.88	(lb/hour)	+	1.38	(lb/hour)	=	2.26	(lb/hour)
CO	0.89	(lb/hour)	+	1.40	(lb/hour)	=	2.29	(lb/hour)
VOC	0.17	(lb/hour)	+	0.27	(lb/hour)	=	0.44	(lb/hour)
NH_3	0.45	(lb/hour)	+	0.71	(lb/hour)	=	1.16	(lb/hour)

b. **Daily Post-Project Potential to Emit (PE2)**

Total Daily Emissions								
	Turbine			Duct Burner			Total	
NO_X	20.6	(lb/day)	+	23.2	(lb/day)	=	43.8	(lb/day)
SO_X	4.4	(lb/day)	+	5.5	(lb/day)	=	9.9	(lb/day)
PM_{10}	19.9	(lb/day)	+	33.2	(lb/day)	=	53.1	(lb/day)
CO	251.8	(lb/day)	+	33.7	(lb/day)	=	285.5	(lb/day)
VOC	45.9	(lb/day)	+	6.4	(lb/day)	=	52.3	(lb/day)
NH_3	10.3	(lb/day)	+	17.1	(lb/day)	=	27.4	(lb/day)

c. Annual Post-Project Potential to Emit (PE2)

Total Annual Emissions									
	Turbine			Duct Burner			Total	
NO_X	5,411	(lb/year)	+	8,454	(lb/year)	=	13,865	(lb/year)
SO_X	1,689	(lb/year)	+	1,995	(lb/year)	=	3,684	(lb/year)
PM_{10}	7,704	(lb/year)	+	12,117	(lb/year)	=	19,821	(lb/year)
CO	9,204	(lb/year)	+	12,303	(lb/year)	=	21,507	(lb/year)
VOC	1,523	(lb/year)	+	2,349	(lb/year)	=	3,872	(lb/year)
NH_3	3,971	(lb/year)	+	6,245	(lb/year)	=	10,216	(lb/year)

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

Pursuant to 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.

Pre-Project Stationary Source Potential to Emit [SSPE1] (lb/year)						
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC	NH_3
S-6534-3-2 (turbine)	5,556	1,679	9,381	9,054	1,626	7,994
S-6534-3-2 (duct burner)	8,582	2,656	14,913	12,538	2,388	12,687
S-6534-3-2 (total)	14,138	4,335	19,999*	19,999*	4,014	19,999*
Pre-Project SSPE (SSPE1)	14,138	4,335	19,999	19,999	4,014	19,999

* The facility requested to limit CO, PM_{10}, and NH_3 emissions to less than 20,000 lb/year. The applicant keeps a record of annual CO, PM_{10}, and NH_3 emissions to ensure compliance with these limits.

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

Pursuant to 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.

As stated previously, the duct burner with the T-60 turbine in this project (listed on permit S-6534-5) and the duct burner with the T-65 turbine (listed on permit S-6534-3) will share a combined heat input limit of 106.4 MMBtu/hr. Therefore for worst case calculation, the emissions from the duct burner with the T-60 turbine in this project (listed on permit S-6534-5) will not be included in the SSPE calculation (as the emissions from the duct burner with the T-65 turbine (listed on permit S-6534-5) has a greater potential to emit for all pollutants).

Post-Project Stationary Source Potential to Emit [SSPE2] (lb/year)						
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC	NH_3
S-6534-3-2 (turbine)	5,556	1,679	9,381	9,054	1,626	7,994
S-6534-3-2 (duct burner)	8,582	2,656	14,913	12,538	2,388	12,687
S-6534-3-2 (total)	14,138	4,335	19,999	19,999	4,014	19,999
S-6534-5-0 (turbine)	5,411	1,689	7,704	9,204	1,523	3,971
S-6534-5-0 (duct burner)*	~~8,454~~	~~1,995~~	~~12,117~~	~~12,303~~	~~2,349~~	~~10,216~~
Post-Project SSPE (SSPE2)	19,549	6,024	27,703	29,203	5,537	23,970

* The duct burners listed on permits S-6534-3-2 and S-6534-5-0 will share a combined heat input limit of 106.4 MMBtu/hr based on the higher heating value of natural gas. This will be enforced by permit condition. The worst case duct burner emissions will be used for the SSPE calculations.

5. Major Source Determination

<u>Rule 2201 Major Source Determination</u>

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Pre-Project SSPE (SSPE1)	14,138	4,335	19,999	19,999	4,014
Post Project SSPE (SSPE2)	19,549	6,024	27,703	29,203	5,537
Major Source Threshold	20,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No

As seen in the table above, the facility is not an existing Major Source and is not becoming a Major Source as a result of this project.

Rule 2410 Major Source Determination

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). Therefore the following PSD Major Source thresholds are applicable.

PSD Major Source Determination (tons/year)							
	NO2	VOC	SO2	CO	PM	PM10	CO2e
Estimated Facility PE before Project Increase	7.1	2.0	2.2	10.0	10.0	10.0	88,915
PSD Major Source Thresholds	250	250	250	250	250	250	100,000
PSD Major Source ? (Y/N)	N	N	N	N	N	N	N

GHG Calculations

Basis and Assumptions

- Emission factors and global warming potentials (GWP) are taken from EPA 40 CFR Part 98, Subpart A, Tables C-1 and C-2:

  Natural Gas
  CO_2 53.02 kg/MMBtu (116.89 lb/MMBtu)
  CH_4 1.0×10^{-3} kg/MMBtu (0.0022 lb/MMBtu)
  N_2O 1.0×10^{-4} kg/MMBtu (0.00022 lb/MMBtu)

  GWP for CH4 = 21 lb-CO2(eq) per lb-CH4
  GWP for N2O = 310 lb-CO2(eq) per lb-N2O

Calculations

CO2 Emissions = (67.1+106.4) MMBtu/hr x 116.89 lb/MMBtu x 8,760 hours/year
= 177,656,435.4 lb-CO2(eq)/year
CH4 Emissions = (67.1+106.4) MMBtu/hr x 0.0022 lb/MMBtu x 21 lb-CO2(eq) per lb-CH4 x 8,760 hours/year
= 70,217.532 lb-CO2(eq)/year
N2O Emissions = (67.1+106.4) MMBtu/hr x 0.00022 lb/MMBtu x 310 lb-CO2(eq) per lb-N2O x 8,760 hours/year
= 103,654.452 lb-CO2(eq)/year

Total = 177,656,435.4 + 70,217.532 + 103,654.452 = 177,830,307.4 lb-CO2(eq)/year
Total = 177,830,307.4 lb-CO2(eq)/year ÷ 2,000 lb/ton = **88,915 short tons-CO2(eq)/year**

6. Baseline Emissions (BE)

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

Pursuant to District Rule 2201, BE = Pre-project Potential to Emit for:

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

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

As shown in Section VII.C.5 above, the facility is not a Major Source for any pollutant.

Therefore BE = PE1.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 Major Modification.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification. Additionally, since the facility is not a major source for PM_{10} (140,000 lb/year), it is not a major source for $PM_{2.5}$ (200,000 lb/year).

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to pollutants for which the District is in attainment or for unclasssified, pollutants. The pollutants addressed in the PSD applicability determination are listed as follows:

- NO_2 (as a primary pollutant)
- SO_2 (as a primary pollutant)
- CO
- PM
- PM10
- Greenhouse gases (GHG): CO_2, N_2O, CH_4, HFCs, PFCs, and SF_6

The first step of this PSD evaluation consists of determining whether the facility is an existing PSD Major Source or not (See Section VII.C.5 of this document).

In the case the facility is an existing PSD Major Source, the second step of the PSD evaluation is to determine if the project results in a PSD significant increase.

In the case the facility is NOT an existing PSD Major Source but is an existing source, the second step of the PSD evaluation is to determine if the project, by itself, would be a PSD major source.

In the case the facility is new source, the second step of the PSD evaluation is to determine if this new facility will become a new PSD major Source as a result of the project and if so, to determine which pollutant will result in a PSD significant increase.

I. Potential to Emit for New or Modified Emission Units vs PSD Major Source Thresholds

As a screening tool, the project potential to emit from all new and modified units is compared to the PSD major source threshold, and if total project potential to emit from all new and modified units is below this threshold, no futher analysis will be needed.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). Therefore the following PSD Major Source thresholds are applicable.

PSD Major Source Determination: Potential to Emit (tons/year)							
	NO2	VOC	SO2	CO	PM	PM10	CO2e
Total PE from New and Modified Units	9.8	1.9	3.0	14.6	13.9	13.9	123,584
PSD Major Source Thresholds	250	250	250	250	250	250	100,000
New PSD Major Source ? (Y/N)	N	N	N	N	N	N	Y

GHG Calculations

Basis and Assumptions

- Emission factors and global warming potentials (GWP) are taken from EPA 40 CFR Part 98, Subpart A, Tables C-1 and C-2:

  Natural Gas
  CO_2 53.02 kg/MMBtu (116.89 lb/MMBtu)
  CH_4 1.0×10^{-3} kg/MMBtu (0.0022 lb/MMBtu)
  N_2O 1.0×10^{-4} kg/MMBtu (0.00022 lb/MMBtu)

  GWP for CH4 = 21 lb-CO2(eq) per lb-CH4
  GWP for N2O = 310 lb-CO2(eq) per lb-N2O

Calculations

CO2 Emissions = (67.1+67.65+106.4) MMBtu/hr x 116.89 lb/MMBtu x 8,760 hours/year
= 246,927,085.9 lb-CO2(eq)/year
CH4 Emissions = (67.1+67.65+106.4) MMBtu/hr x 0.0022 lb/MMBtu x 21 lb-CO2(eq) per lb-CH4 x 8,760 hours/year
= 97,596.30 lb-CO2(eq)/year
N2O Emissions = (67.1+67.65+106.4) MMBtu/hr x 0.00022 lb/MMBtu x 310 lb-CO2(eq) per lb-N2O x 8,760 hours/year
= 144,070.73 lb-CO2(eq)/year

Total = (246,927,085.9 + 97,596.30 + 144,070.73) lb-CO2(eq)/year
= 247,168,752.9 lb-CO2(eq)/year
Total = 247,168,752.9 lb-CO2(eq)/year ÷ 2,000 lb/ton = **123,584 short tons-CO2(eq)/year**

As demonstrated in the table above, the project potential to emit, for all new and modified emission units exceeds one or more of the PSD major source thresholds. Consequently, further analysis is required to determine if the project results in an emission increase greater than the PSD major source threshold.

II. Emission Increase of Each Attainment/Unclassified Pollutant from New or Modified Emission Units vs PSD Major Source Thresholds

In this step, the emission increase for each attainment/unclassified pollutant is compared to the PSD major source thresholds, and if emission increase for each attainment pollutant is below this threshold, no futher analysis is needed.

For new emissions units, the increase in emissions is equal to the PE2 for each new unit included in this project.

For existing emissions units, the increase in emissions is calculated as follows.

Emission Increase = PAE – BAE – UBC

Where: PAE = Projected Actual Emissions, and
BAE = Baseline Actual Emissions
UBC = Unused baseline capacity

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If there is no increase in design capacity or potential to emit, the PAE is equal to the annual emission rate at which the unit is projected to emit in any one year, selected by the operator, within 5 years after the unit resumes normal operation (10 years for existing units with an increase in design capacity or potential to emit). If detailed PAE are not provided, the PAE is equal to the PE2 for each permit unit.

The BAE is calculated based on historical emissions and operating records for any 24 month period, selected by the operator, within the previous 10 year period (5 years for electric utility steam generating units). The BAE must be adjusted to exclude any non-compliant operation emissions and emissions that are no longer allowed due to lower applicable emission limits that were in effect when this application was deemed complete.

UBC: Since this project does not result in an increase in annual potential to emit for this permit unit, the UBC is the portion of PAE that the emission units could have accommodated during the baseline period.

$(\text{Emission Increase})_E = \text{PAE} - \text{BAE} - \text{UBC} = 0$

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Per 40 CFR 51.165 (a)(2)(ii)(D) for new emissions units in this project,

$(\text{Emission Increase})_N = \text{PE2}_N - \text{BAE}$

BAE = 0 for the new unit therefore $(\text{Emission Increase})_N = \text{PE2}_N$

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The Emission Increase for this project is thus calculated as follows:

$\text{Emission Increase} = (\text{Emission Increase})_E + (\text{Emission Increase})_N$
$\text{Emission Increase} = 0 + \text{PE2}_N$
$\text{Emission Increase} = \text{PE2}_N$

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). Therefore the following PSD Major Source thresholds are applicable.

PSD Major Source Determination: Emission Increase (tons/year)							
	NO2	VOC	SO2	CO	PM	PM10	CO2e
Project Emission Increase	6.9	1.9	1.8	10.8	9.9	9.9	89,197
PSD Major Source Thresholds	250	250	250	250	250	250	100,000
New PSD Major Source ? (Y/N)	N	N	N	N	N	N	N

GHG Calculations

Basis and Assumptions

- Emission factors and global warming potentials (GWP) are taken from EPA 40 CFR Part 98, Subpart A, Tables C-1 and C-2:

  Natural Gas
  CO_2 53.02 kg/MMBtu (116.89 lb/MMBtu)
  CH_4 1.0×10^{-3} kg/MMBtu (0.0022 lb/MMBtu)
  N_2O 1.0×10^{-4} kg/MMBtu (0.00022 lb/MMBtu)

  GWP for CH4 = 21 lb-CO2(eq) per lb-CH4
  GWP for N2O = 310 lb-CO2(eq) per lb-N2O

Calculations

CO2 Emissions = (67.65+106.4) MMBtu/hr x 116.89 lb/MMBtu x 8,760 hours/year
= 178,219,611.4 lb-CO2(eq)/year
CH4 Emissions = (67.65+106.4) MMBtu/hr x 0.0022 lb/MMBtu x 21 lb-CO2(eq) per lb-CH4 x 8,760 hours/year
= 70,440.12 lb-CO2(eq)/year
N2O Emissions = (67.65+106.4) MMBtu/hr x 0.00022 lb/MMBtu x 310 lb-CO2(eq) per lb-N2O x 8,760 hours/year
= 103,983.04 lb-CO2(eq)/year

Total = (178,219,611.4 + 70,440.12 + 103,983.04) lb-CO2(eq)/year
= 178,394,034.6 lb-CO2(eq)/year
Total = 178,394,034.6 lb-CO2(eq)/year ÷ 2,000 lb/ton = **89,197 short tons-CO2(eq)/year**

As shown in the table above, the project emission increase, for all new and modified emission units, does not exceed any of the PSD major source thresholds. Therefore Rule 2410 is not applicable and no further discussion is required.

10. Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

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Quarterly NEC [QNEC]			
	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO_X	3,535	3,535	0
SO_X	1,084	1,084	0
PM_{10}	5,000	5,000	0
CO	5,000	5,000	0
VOC	1,004	1,004	0

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Quarterly NEC [QNEC]			
	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO_X	3,466	0	3,466
SO_X	921	0	921
PM_{10}	4,955	0	4,955
CO	5,377	0	5,377
VOC	968	0	968

VIII. Compliance

Rule 1080 Stack Monitoring

This rule specifies that specific source types be equipped with CEMs. The proposed emission unit is not one of the listed source types. Additionally, this rule specifies performance, data reduction, recordkeeping, and reporting criteria for continuous emissions monitors.

Since the turbine will not be equipped with CEMS, the provisions of this rule are not applicable to this project.

Rule 1081 Source Sampling

This rule requires adequate and safe facilities for using in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection. The following conditions will be listed on the permit to ensure compliance:

- The owner or operator shall be required to conform to the sampling facilities and testing procedures described in District Rule 1081 (as amended 12/16/93), Sections 3.0 and 6.1. [District Rule 1081]

- The District must be notified 30 days prior to any performance testing and a test plan shall be submitted for District approval 15 days prior to such testing. [District Rule 1081]
- Performance testing shall be witnessed or authorized by District personnel. Test results must be submitted to the District within 60 days of performance testing. [District Rule 1081]

Therefore, compliance with the requirements of this rule is expected.

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. The following conditions will be listed on the permit to ensure compliance:

- 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]
- 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]

Therefore, compliance with the requirements of this rule is expected.

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

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

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As seen in Section VII.C.2 above, the applicant is proposing to install a new natural gas-fired turbine with heat recovery with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X and VOC since the PEs are greater than 2 lbs/day. However BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 above and ammonia emissions are intrinsic to the operation of the selective catalytic reduction (SCR) system, which is BACT for NOx emissions. Emissions from a control device that is determined by the District to be BACT are not subject to BACT.

Natural Gas-Fired Turbine with Heat Recovery		
Pollutant	**Daily PE2**	**BACT Triggered?**
NO_x	43.8	Yes
SO_x	9.9	Yes
PM_{10}	53.1	Yes
CO	285.5	No*
VOC	52.3	Yes
NH_3	27.4	No*

* BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year. BACT is not triggered for NH_3 since emissions from a control device that is determined to be BACT is not subject to BACT.

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

As discussed in Section I 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

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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 PE 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))

There are no emission factor changes proposed for this permit unit. Therefore, EF2 / EF1 = 1.

Adjusted Increase in Permitted Emissions				
Pollutant	PE2 (lb/day)	PE1 (lb/day)	AIPE (lb/day)	BACT Triggered?
NO_X	44.3	44.3	0.0	No
SO_X	11.9	11.9	0.0	No
PM_{10}	66.5	66.5	0.0	No
CO	103.8	103.8	0.0	No
VOC	15.6	15.6	0.0	No
NH_3	56.6	56.6	0.0	No

As demonstrated above, the AIPE is not greater than 2 lb/day. Therefore BACT is not triggered.

d. SB 288/Federal Major Modification

As discussed in Section VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 and/or Federal Major Modification. Therefore BACT is not triggered for any pollutant.

2. BACT Guideline

BACT Guideline 3.4.3 applies to the natural gas-fired turbine in this project. [Fossil Fuel-Fired I.C. Engine] (See Attachment B)

3. Top-Down 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.

Pursuant to the attached Top-Down BACT Analysis (see Attachment B), BACT has been satisfied with the following:

SO_X: PUC-regulated natural gas or non-PUC-regulated natural gas with < 0.75 grains-S/100 dscf
PM_{10}: Air inlet cooler, lube oil vent coalescer, and natural gas fuel
VOC: 2.0 ppmvd @ 15% O2, based on a three-hour average (catalytic oxidation)

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Post-Project SSPE (SSPE2)	19,549	6,024	27,703	29,203	5,537
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Public noticing is required for:
a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required for this project for new Major Source purposes.

As demonstrated in VII.C.7 and VII.C. 8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

b. PE > 100 lb/day

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO_X	43.8	100 lb/day	No
SO_X	9.9	100 lb/day	No
PM_{10}	53.1	100 lb/day	No
CO	285.5	100 lb/day	Yes
VOC	52.3	100 lb/day	No
NH_3	27.4	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

The following table compares pollutant will trigger public noticing requirements. As seen 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	14,138	19,549	20,000 lb/year	No
SO_X	4,335	6,024	54,750 lb/year	No
PM_{10}	19,999	27,703	29,200 lb/year	No
CO	19,999	29,203	200,000 lb/year	No
VOC	4,014	5,537	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

d. SSIPE > 20,000 lb/year

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. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

Stationary Source Increase in Permitted Emissions [SSIPE] – Public Notice					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	19,549	14,138	5,411	20,000 lb/year	No
SO_x	6,024	4,335	1,689	20,000 lb/year	No
PM_{10}	27,703	19,999	7,704	20,000 lb/year	No
CO	29,203	19,999	9,204	20,000 lb/year	No
VOC	5,537	4,014	1,523	20,000 lb/year	No
NH_3	23,970	19,999	3,971	20,000 lb/year	No

As demonstrated above, the SSIPEs for all pollutants were less than 20,000 lb/year; therefore public noticing for SSIPE purposes is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for the turbine CO emissions in excess of 100 lb/day. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC permit for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. 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. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions

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- During startup of the turbine, emissions shall not exceed any of the following limits: 2.9 lb-NOx (as NO_2)/startup; 18.9 lb-CO/startup; or 2.1 lb-VOC (as methane)/startup. [District Rule 2201]
- During shutdown of the turbine, emissions shall not exceed any of the following limits: 0.5 lb-NOx (as NO_2)/shutdown; 5.6 lb-CO/shutdown; or 0.5 lb-VOC (as methane)/shutdown. [District Rule 2201]
- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) – 2.5 ppmvd @ 15% O2 or 1.60 lb/hr; CO – 6.0 ppmvd @ 15% O2 or 2.33 lb/hr; and VOC (as methane) – 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]
- PM10 emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.78 lb/hr or 0.016 lb/MMBtu. [District Rule 2201 and 40 CFR 60.43b(h)(i)]
- SOx emissions (with or without duct burner firing) shall not exceed 0.00285 lb/MMBtu. [District Rule 2201 and 40 CFR 60.333b]
- NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst) except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) – 2.5 ppmvd @ 15% O2 or 0.62 lb/hr; CO – 6.0 ppmvd @ 15% O2 or 0.90 lb/hr; and VOC (as methane) – 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]
- PM10 emissions from this unit (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 1.07 lb/hr or 0.016 lb/MMBtu. [District Rule 2201]
- The ammonia slip (NH3) emissions (with duct burner firing) shall not exceed either of the following limits: 2.36 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rule 2201]
- The ammonia slip (NH3) emissions (without the duct burner firing) shall not exceed either of the following limits: 0.91 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rule 2201]

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- During startup of the unit, emissions shall not exceed any of the following limits: 0.8 lb-NOx (as NO2)/startup; 78.5 lb-CO/startup; or 1.3 lb-VOC(as methane)/startup. [District Rule 2201]

- During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NOx (as NO2/shutdown; 34.7 lb-CO/shutdown; or 0.5 lb-VOC (as methane)/shutdown. [District Rule 2201]
- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.58 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 2.29 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]
- PM10 emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.26 lb/hr or 0.013 lb/MMBtu. [District Rule 2201]
- NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) 2.5 ppmvd @ 15% O2 or 0.61 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 0.89 lb/hr; and VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]
- PM10 emissions from this unit (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 0.88 lb/hr or 0.013 lb/MMBtu. [District Rule 2201]
- The ammonia slip (NH3) emissions (with duct burner firing) shall not exceed either of the following limits: 1.16 lb/hr or 5.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]
- The ammonia slip (NH3) emissions (without the duct burner firing) shall not exceed either of the following limits: 0.45 lb/hr or 5.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]

E. Compliance Assurance

1. Source Testing

Pursuant to District Policy APR 1705, source testing is required to demonstrate compliance with Rule 2201.

The following conditions will be placed on the permit to ensure compliance with the assumptions made for Rule 2201. Source testing will be required within 120 days of initial start-up since there will be a commissioning period of up to 60 days.

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- Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted at least once every twelve months. [District Rules 2201, 4001, 4703, and 40 CFR 60.46]
- Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [40 CFR 60.335(b)(3) and District Rule 4703, 6.3.3]

- NO_x emissions (referenced as NO_2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR Part 60 Subpart GG Section 60.335. [District Rules 1081, 2201, 4001, and 4703]
- VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules 1081 and 2201]
- CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rules 1081, 2201, and 4703]
- Source testing to measure PM10 emissions shall be conducted using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201]
- Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B [District Rules 1081, 2201, and 4102]
- The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4703]

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- Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 120 days of startup (not including commissioning) and at least once every twelve months thereafter. [District Rules 2201, 4102, and 4703 and 40 CFR 60.4400(a)]
- Performance testing to measure the PM10 emissions (lb/hr) shall be conducted within 120 days of startup (not including commissioning). [District Rule 2201]
- NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]
- VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules 1081 and 2201]
- CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703]
- PM10 emissions shall be determined using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201]
- Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081, 2201, and 4102]

2. Monitoring

The following conditions will be listed on the permit to ensure compliance with the assumptions made for Rule 2201.

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- Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. [District Rules 2201 and 4102]

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- During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]
- If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]
- The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, and O2 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703]
- If the NOx and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee

may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703]

- Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. The permittee shall submit a detailed calculation protocol or monitoring plan for District Approval at least 60 days prior to the commencement of operation. [District Rules 2201 and 4102]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following conditions will be listed on the permit to ensure compliance:

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- The permittee shall maintain records of the amount of fuel combusted in the duct burners listed on permits S-6534-3 and S-6534-5 and calculated combined heat input. [District Rule 2201]
- The facility shall maintain a record of the cumulate 12 month rolling NOx, CO, VOC, SOx, PM10, and NH3 emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201]
- The facility shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201]

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- The permittee shall maintain records of the amount of fuel combusted in the duct burners listed on permits S-6534-3 and S-6534-5 and calculated combined heat input. [District Rule 2201]
- The permittee shall maintain a record of the cumulative 12 month rolling NOx, CO, VOC, SOx, PM10, and NH3 emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201]
- The permittee shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201]
- The sulfur fuel content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored weekly using ASTM Methods D4084, D5504, D6228, or Gas Processors Association Standard 2377. If the turbine sulfur fuel content is less than 1.0 gr/100 scf for 8 consecutive weeks, then the monitoring frequency shall be every

6 months. If the duct burner sulfur fuel content is less than 0.75 gr/100 scf for 8 consecutive weeks, then the monitoring frequency shall be every 6 months. If any six-month monitoring tests result in a sulfur fuel content exceedance, weekly monitoring shall resume. [Rule 2201 and 40 CFR 60.4365 and 60.4415]

- All records shall be retained for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070, 2201, and 4703]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to Attachment C of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NOx, CO, and SOx. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NOx, CO, or SOx.

The proposed location is in a non-attainment area for the state's PM10 as well as federal and state PM2.5 thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM10 and PM2.5.

Rule 2410 Prevention of Significant Deterioration

The prevention of significant deterioration (PSD) program is a construction permitting program for new major stationary sources and major modifications to existing major stationary sources located in areas classified as attainment or in areas that are unclassifiable for any criteria air pollutant.

As demonstrated above, this project is not subject to the requirements of Rule 2410 due to a significant emission increase and no further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 2540 Acid Rain Program

Pursuant to CFR 40 Section 72.7, the acid rain program standards apply to any new utility that serves one or more generators with a total nameplate capacity of 25 MWe or more and burns only fuel with a sulfur content of 0.05 percent or less by weight. The nameplate rating for the proposed unit is 5.67 MWe. Thus, this unit is not subject to the Part 72 Acid Rain Program requirements and an application for an acid rain permit is not required.

Rule 4001 New Source Performance Standards (NSPS)

40 CFR 60 – Subpart GG – Standards of Performance for Stationary Gas Turbines

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. The proposed turbine is new. Therefore, the proposed turbine meets the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. The proposed turbine is new. Therefore, the proposed turbine also meets the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to the proposed turbine. Therefore, the turbine is exempt from the requirements of 40 CFR 60 Subpart GG.

40 CFR 60 – Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

40 CFR Part 60 Subpart KKKK applies to all stationary combustion turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbine involved in this project has a rating of 67.65 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to the gas turbine.

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 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh).

The facility is proposing a NO_X emission concentration limit of 2.5 ppmvd @ 15% O_2 for the turbine. Therefore, the proposed turbine will be operating in compliance with the NO_X emission requirements of this subpart. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

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- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) – 2.5 ppmvd @ 15% O2 or 1.60 lb/hr; CO – 6.0 ppmvd @ 15% O2 or 2.33 lb/hr; and VOC (as methane) – 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]
- NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst) except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) – 2.5 ppmvd @ 15% O2 or 0.62 lb/hr; CO – 6.0 ppmvd @ 15% O2 or 0.90 lb/hr; and VOC (as methane) – 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]

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- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.58 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 2.29 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]
- NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) 2.5 ppmvd @ 15% O2 or 0.61 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 0.89 lb/hr; and VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

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.

The facility is proposing to burn natural gas fuel in the turbine with a maximum sulfur content of 1.0 grain/100 scf (0.00285 lb/MMBtu) and a 50/50 mixture of natural gas/biogas fuel in the duct burner with a maximum sulfur content of 0.75 grain/100 scf (0.00214 lb/MMBtu).

Therefore, the proposed system will be operating in compliance with the SO_X emission requirements of this section. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

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- This unit shall be fired exclusively on PUC-regulated natural gas and the PUC-regulated natural gas shall have a total sulfur content of less than or equal to 1.0 gr/100 scf. [40 CFR 60.4330, and District Rules 2201 and 4801]
- SOx emissions (with or without the duct burner firing) shall not exceed 0.00285 lb/MMBtu. [District Rule 2201 and 40 CFR 60.4330]

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- The turbine shall be fired exclusively on PUC-regulated natural gas and the PUC-regulated natural gas shall have a total sulfur content of less than or equal to 1.0 gr/100 scf. [40 CFR 60.4330 and District Rules 2201 and 4801]
- The duct burner shall be fired on PUC-regulated natural gas and/or biogas and or any mixture thereof and shall have a total sulfur content of less than or equal to 0.75 gr/100 scf. [40 CFR 60.4330 and District Rules 2201 and 4801]

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).

The turbines do not utilize water or steam injection. Therefore, the requirements of this section are not applicable to this project.

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection

Paragraph (a) states if you are not using water or steam injection to control NOx emissions, you must perform annual performance tests in accordance with Section 60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NOx emission limit for the turbine, you must resume annual performance tests.

Paragraph (b) states as an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems: (1) Continuous emission monitoring as described in Sections 60.4335(b) and 60.4345, or (2) Continuous parameter monitoring as follows: (i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NOx formation characteristics, and you must monitor these parameters continuously. (ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOx mode. (iii) For any turbine that uses SCR to reduce NOx emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls. (iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NOx emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in § 75.19(c)(1)(iv)(H).

The following condition will be listed on the permits to ensure compliance with the requirements of this section:

- Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 120 days of startup (not including commissioning) and at least once every twelve months thereafter. [District Rules 2201 and 4703 and 40 CFR 60.4340]

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.

The facility will not install and operate a NO_X CEMS in accordance with the requirements of this section. Therefore, the requirements of this section are not applicable to this project.

Section 60.4350 – CEMS Data and Excess NO_X Emissions

Section 60.4350 states that for purposes of identifying excess emissions:

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

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

(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).

The facility will not install and operate a NO_X CEMS in accordance with the requirements of this section. Therefore, the requirements of this section are not applicable to this project.

Section 60.4355 – Parameter Monitoring Plan

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions.

As discussed above, the facility is proposing to perform annual source testing. Therefore, the requirements of this section are not applicable.

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.

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.

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- The sulfur fuel content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored weekly using ASTM Methods D4084, D5504, D6228, or Gas Processors Association Standard 2377. If the sulfur fuel content is less than 1.0 gr/100 scf for 8 consecutive weeks, then the monitoring frequency shall be every 6 months. If any six-month monitoring tests result in a sulfur fuel content exceedance, weekly monitoring shall resume. [40 CFR 60.4365]

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The facility is proposing to operate the turbine on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. The facility has proposed SO2 stack gas monitoring and is not proposing to perform fuel sulfur content monitoring.

The facility is proposing a custom monitoring schedule. The District has previously approved the proposed custom monitoring schedule for this facility in project S-1055631. The permittee is proposing monitoring at least once per week and then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every month. If any monthly monitoring period shows an exceedance, weekly monitoring shall resume. The facility is proposing to follow this same pre-approved SOx monitoring scheme for this turbine. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- The permittee shall monitor and record the stack concentration of NOx (as NO2), SOx (as SO2), CO, and O2 weekly. If compliance with the NOx, SOx, and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703 and 40 CFR 60.4365 and 60.4415]

<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, the facility is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

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

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

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

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

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

The facility is not proposing to use CEMs or monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this section are not applicable.

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.

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The facility performs fuel sulfur content monitoring on a weekly or bi-annual basis. Therefore, the requirements of this section are not intended for this monitoring schedule.

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The facility is not proposing to monitor fuel sulfur content. Therefore, the requirements of this section are not applicable to this project.

Sections 60.4375 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. The facility is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbine 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 excess emissions and monitoring downtime 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 the cause of excess (if known), corrective actions taken and preventative measures adopted; Applicable time and date of each period during monitor downtime; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375 and 60.4395]

Section 60.4400 – NO_X Performance Testing

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

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

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

- Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 120 days of startup (not including commissioning) and at least once every twelve months thereafter. [District Rules 2201 and 4703 and 40 CFR 60.4340 and 60.4400]
- NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]

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).

The facility will not install and operate a NOx CEMS in accordance with the requirements of this section. Therefore, the requirements of this section are not applicable to this project.

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, the facility is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable.

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).

(2) Measure the SO2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see § 60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P}$$

Where:

E = SO2 emission rate, in lb/MWh
1.664 × 10−7 = conversion constant, in lb/dscf-ppm
(SO2)c = average SO2 concentration for the run, in ppm
Qstd = stack gas volumetric flow rate, in dscf/hr
P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(3) Measure the SO2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see § 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the SO2 emission rate in lb/MWh.

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The facility is not proposing to perform SOx performance testing. Therefore, the requirements of this section are not applicable to this unit.

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The facility is proposing SO2 stack gas monitoring. The SO2 stack gas will be determined using the methods specified above. Therefore, the proposed turbine will be operating in compliance with the requirements of this section. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

- The permittee shall monitor and record the stack concentration of NOx (as NO2), SOx (as SO2), CO, and O2 weekly. If compliance with the NOx, SOx, and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703 and 40 CFR 60.4415]
- If the NOx, SOx, and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx, SOx, and CO concentrations to the permitted emission limits as soon as

possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703 and 40 CR 60.4415]

- SOx emissions (referenced to SO2) shall be determined using EPA Methods 6, 6C, 8, 3A, 20, ASME PTC 19-10-1981-Part 10, or EPA Methods 1 and 2. [District Rules 1081 and 2201 and 40 CFR 60.4415]

Conclusion

Conditions will be incorporated into the permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

40 CFR 63 – Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Section 63.6080 states Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

Section 63.6085 states you are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

(a) Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

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

This stationary source has the potential to emit of any single HAP less than 10 tons per year and combination of HAPs less than 25 tons per year. Therefore, the requirements of this subpart are not applicable to this project.

Rule 4101 Visible Emissions

Rule 4101 states that 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.

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

- 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. Therefore, compliance with this rule is expected and the following condition will be listed on the permit 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 Assessment)

District Policy APR 1905 – Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than or equal to one. According to the Technical Services Memo for this project (Attachment C), the total facility prioritization score including this project was less than or equal to one. Therefore, no future analysis is required to determine the impact from this project and compliance with the District's Risk Management Policy is expected.

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

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

Rule 4201 Particulate Matter Concentration

Section 3.0 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.

Particulate matter calculations were performed for each piece of equipment by the following equation:

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All PM emitted from the common exhaust stack is expected to be 10 microns or less in diameter.

PE_{PM} = 2.78 lb/hr

$$\mathrm{PM}\left(\frac{\mathrm{gr}}{\mathrm{dscf}}\right) = \frac{\left(2.78\,\frac{\mathrm{lb\text{-}PM}}{\mathrm{hr}}\right)\times\left(7{,}000\,\frac{\mathrm{gr\text{-}PM}}{\mathrm{lb\text{-}PM}}\right)}{\left(173.5\,\frac{\mathrm{MMBtu}}{\mathrm{hr}}\right)\times\left(8{,}578\,\frac{\mathrm{dscf}}{\mathrm{MMBtu}}\right)} = 0.013\,\frac{\mathrm{gr\text{-}PM}}{\mathrm{dscf}}$$

S-6534-5-0

F-Factor for natural gas: 8,578 dscf/MMBtu
PM_{10} Emission Factor: 0.013 lb-PM_{10}/MMBtu
Percentage of PM as PM_{10} in Exhaust: 100%

$$GL = \left(\frac{0.013\ lb-PM}{MMBtu}\times\frac{7{,}000\,grain}{lb-PM}\right) / \left(\frac{8{,}578\ ft^3}{MMBtu}\right)$$

$$GL = 0.01\ grain/dscf < 0.1\,grain/dscf$$

Since the particulate matter concentration is ≤ 0.1 grains per dscf, compliance with Rule 4201 is expected.

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

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

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr.

Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the proposed equipment.

Rule 4301 Fuel Burning Equipment

This rule specifies maximum emission rates in lb/hr for SO_2, NO_2, and combustion contaminants (defined as total PM in Rule 1020). This rule also limits combustion contaminants to ≤ 0.1 gr/scf. According to AP 42 (Table 1.4-2, footnote c), all PM emissions from natural gas combustion are less than 1 μm in diameter. As shown below, the unit's maximum hourly emission rates are below the Rule 4301 limits.

District Rule 4301 Limits			
Unit	**NO_2**	**Total PM**	**SO_2**
S-6534-3-4	1.85	2.77	0.50
S-6534-5-0	1.83	2.21	0.41
Rule 4301 Limit	**140 lb/hr**	**10 lb/hr**	**200 lb/hr**

As shown above, compliance with this rule is expected.

Rule 4305 Boilers, Steam Generators, and Process Heaters (Phase 2)

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

Rule 4305 Section 4.1.4 exempts unfired and fired waste heat recovery boilers from the requirements of this rule provided that the waste heat recovery boiler is used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The duct burner and heat recovery steam generator are a fired waste heat recovery boiler used to augment the heat from the exhaust of the Solar Turbines Inc. turbine. Therefore, the requirements of Rule 4305 are not applicable to the duct burner.

Rule 4306 Boilers, Steam Generators, and Process Heaters (Phase 3)

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

Rule 4306 Section 4.1.4 exempts unfired and fired waste heat recovery boilers from the requirements of this rule provided that the waste heat recovery boiler is used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The duct burner and heat recovery steam generator are a fired waste heat recovery boiler used to augment the heat from the exhaust of the Solar Turbines Inc. turbine. Therefore, the requirements of Rule 4306 are not applicable to the duct burner.

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

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input greater than 5 million Btu per hour.

Rule 4320 Section 4.1.4 exempts unfired and fired waste heat recovery boilers from the requirements of this rule provided that the waste heat recovery boiler is used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The duct burner and heat recovery steam generator are a fired waste heat recovery boiler used to augment the heat from the exhaust of the Solar Turbines Inc. turbine. Therefore, the requirements of Rule 4320 are not applicable to the duct burner.

Rule 4703 Stationary Gas Turbines

Rule 4703 limits NOx and CO emissions from stationary gas turbines with ratings of greater than 0.3 megawatts and/or maximum heat input ratings of more than 3,000,000 Btu/hr. The facility proposes to install one 5.67 MW gas turbine, therefore this rule applies.

<u>Section 5.1 – NOx Emission Requirements</u>

Section 5.1.1 (Tier I) of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR), based on the following equation:

$$NO_X \text{ (ppmv @ 15\% } O_2) = 9 \times \left(\frac{EFF}{25}\right)$$

Where EFF is the higher of EFF_1 or EFF_2 where:

$$EFF_1 = \frac{3{,}412 \frac{Btu}{kW-hr}}{\text{Actual Heat Rate @ HHV } (\frac{Btu}{kW-hr})} \times 100 \text{, and } EFF_2 = EFF_{MFR} \frac{LHV}{HHV}$$

$$EFF_2 = EFF_{mfr} * (LHV/HHV)$$

Calculated data indicates that the Actual Heat Rate @ HHV is 10,860 Btu/kW-hr. Therefore:

$$EFF_1 = \frac{3{,}412 \frac{Btu}{kW-hr}}{10{,}860 \frac{Btu}{kW-hr}} \times 100 = 31.42\%$$

$$NO_X \text{ limit utilizing } EFF_1 = 9 \times \left(\frac{31.42}{25}\right) = 11.3 \text{ ppmvd @ } 15\% \ O_2$$

EFF_2 calculations are not necessary since Rule 4703 emission limits will be no lower than 9 ppmv NO_X and the proposed turbines will be limited to a maximum of 2.5 ppmv NO_X @ 15% O_2 (based on a 3-hour average), therefore compliance is expected.

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from combined cycle, stationary gas turbine systems rated at greater than 10 MW to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbine will be limited to 2.5 ppmv @ 15% O_2 (based on a 3-hour average), therefore compliance with this section is expected. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

<u>S-6534-3-4</u>

- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.60 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 2.33 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]
- NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) 2.5 ppmvd @ 15% O2 or 0.62 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 0.90 lb/hr; and VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]

<u>S-6534-5-0</u>

- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.58 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 2.29 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]
- NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) 2.5 ppmvd @ 15% O2 or 0.61 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 0.89 lb/hr; and VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

Section 5.2 – CO Emission Requirements

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbine 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.

The facility is proposing a CO emission concentration limit of 6.0 ppmvd @ 15% O_2 and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbine will be operating the turbine in compliance with the CO emission requirements of this rule. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

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- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.60 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 2.33 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]
- NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) 2.5 ppmvd @ 15% O2 or 0.62 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 0.90 lb/hr; and VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]

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- NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.58 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 2.29 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]
- NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) 2.5 ppmvd @ 15% O2 or 0.61 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 0.89 lb/hr; and VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

Section 5.3 – Startup and Shutdown Requirements

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

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

The facility is proposing to incorporate startup and shutdown provisions into the operating requirements for the proposed turbine. The facility has 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 turbine will be operating in compliance with the startup and shutdown requirements of this rule. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

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- During startup of the unit, emissions shall not exceed any of the following limits: 2.9 lb-NOx (as NO2)/startup; 18.9 lb-CO/startup; or 2.1 lb-VOC(as methane)/startup. [District Rule 2201]
- During shutdown of the unit, emissions shall not exceed any of the following limits: 0.5 lb-NOx (as NO2/shutdown; 5.6 lb-CO/shutdown; or 0.5 lb-VOC (as methane)/shutdown. [District Rule 2201]
- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. 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 30 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

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- During startup of the unit, emissions shall not exceed any of the following limits: 0.8 lb-NOx (as NO2)/startup; 78.5 lb-CO/startup; or 1.3 lb-VOC(as methane)/startup. [District Rule 2201]
- During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NOx (as NO2/shutdown; 34.7 lb-CO/shutdown; or 0.5 lb-VOC (as methane)/shutdown. [District Rule 2201]
- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. 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 30 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]
- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 – Monitoring and Record Keeping

Section 6.2.1 requires the owner or operator to either install, operate, and maintain continuous emissions monitoring equipment for NOx and oxygen, as identified in Rule 1080 (Stack Monitoring), or install and maintain APCO-approved alternate monitoring. The applicant has proposed to determine a relation between the ammonia injection rate and the NOx emissions rate. The applicant will then monitor the ammonia injection rate to the SCR system to determine NOx compliance. To factor in degradation of the SCR catalyst, the applicant will be required to periodically monitor the NOx and O2 emissions rates using a portable analyzer. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

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- Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rules 2201 and 4703]
- During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges. The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]
- If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia

injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]

- The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, and O2 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rule 2201]
- If the NOx and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rule 2201]

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- Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rule 2201 and 4703]
- During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]
- If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as

possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]

- The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, and O2 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703]
- If the NOx and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. The proposed turbine will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable.

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 turbine was not in operation prior to August 18, 1994 and the requirements of this section are not applicable.

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. The facility will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbine will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- All records shall be maintained and retained on-site for a period of at least 5 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. The facility will not install and operate a NOx CEMS. Therefore, the requirements of this section are not applicable to this project.

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. The facility will be required to maintain records of each item listed above. Therefore, the proposed turbine will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will be listed on the permit to ensure compliance with the requirements of this section:

- The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. [District Rule 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. The proposed turbine is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable.

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, the facility will be required, by permit condition, to maintain records of the date, time and duration or each startup and shutdown. Therefore, the proposed turbine will be operating in compliance with the recordkeeping requirements of this rule.

<u>Sections 6.3 and 6.4 – Compliance Testing</u>

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 turbine operated by the facility is subject to the provisions of Section 5.0 of this rule. Therefore, the turbine is required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

- Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 120 days of startup (not including commissioning) and at least once every twelve months thereafter. [District Rules 2201 and 4703 and 40 CFR 60.4340 and 60.4400]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbine will be allowed to operate greater than 877 hours per year. Therefore, the requirements of this section are not applicable.

Section 6.3.3 specifies source testing requirements for units that are equipped with intermittently operated auxiliary burners. The following condition will be listed on the permit to ensure compliance with the requirements of this section:

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

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

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be 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 conditions will be listed on the permit to ensure compliance with the requirements of this section:

- NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]
- CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703]
- The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4703]
- HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [District Rule 4703]

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.

Rule 4801 Sulfur Compounds

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.

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

$$\text{Volume } SO_2 = \frac{n\,RT}{P}$$

With:

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

1.0 gr-S/100 scf:

$$\frac{0.00285\,lb - SOx}{MMBtu} \times \frac{MMBtu}{8{,}578\,dscf} \times \frac{1\,lb \cdot mol}{64\,lb} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times \frac{1{,}000{,}000 \cdot parts}{million} = 1.97\,\frac{parts}{million}$$

0.75 gr-S/100 scf:

$$\frac{0.00214\,lb - SOx}{MMBtu} \times \frac{MMBtu}{8{,}578\,dscf} \times \frac{1\,lb \cdot mol}{64\,lb} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times \frac{1{,}000{,}000 \cdot parts}{million} = 1.48\,\frac{parts}{million}$$

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

Therefore, compliance with District Rule 4801 requirements is expected.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that 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 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 County of Tulare (County) is the public agency having principal responsibility for approving the Project. As such, the County served as the Lead Agency for the project. Consistent with CEQA Guidelines §15303, a Notice of Exemption was prepared and adopted by the County.

The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381).

The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's thresholds of significance for criteria pollutants. Thus, the District concludes that through a combination of project design elements and permit conditions, project specific stationary source emissions will be reduced to less than significant levels. The District does not have authority over any of the other project impacts and has, therefore, determined that no additional findings are required (CEQA Guidelines §15096(h)).

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue Authority to Construct permits S-6534-3-4 and '5-0 subject to the permit conditions on the attached draft Authority to Construct permits in Attachment D.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-6534-3-0	3020-8A-D	5.432 MW	$3,062
S-6534-5-0	3020-8A-D	5.67 MW	$3,062

Attachments

A: Permit to Operate Permit S-6534-3-2
B: BACT Guideline 3.4.3 and Top Down BACT Analysis
C: Health Risk Assessment and Ambient Air Quality Analysis
D: Draft Authority to Construct Permits

Attachment A

Permit to Operate Permit S-6534-3-2

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: S-6534-3-2 **EXPIRATION DATE:** 12/31/2013

EQUIPMENT DESCRIPTION:
5.432 MW ELECTRIC POWER GENERATION SYSTEM (COMBINED CYCLE CONFIGURATION) CONSISTING OF A 67.1 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) SOLAR MODEL #TAURUS 65-8401S NATURAL GAS-FIRED COMBUSTION TURBINE WITH A 106.4 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) NATURAL GAS-FIRED DUCT BURNER, ALL SERVED BY A CO CATALYST AND A SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION

PERMIT UNIT REQUIREMENTS

1. 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]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine and duct burner. Exhaust ducting may be equipped (if required) with a fresh air inlet blower, to lower the exhaust temperature prior to the inlet of the SCR catalyst. [District Rule 2201]
6. The turbine/electrical generator shall be equipped with an air inlet filter and a lube oil vent coalescer (or equivalent). [District Rule 2201]
7. This unit shall be fired exclusively on PUC-regulated natural gas and the PUC-regulated natural gas shall have a total sulfur content of less than or equal to 1.0 gr/100 scf. [40 CFR 60.4330 and District Rules 2201 and 4801]
8. During startup of the unit, emissions shall not exceed any of the following limits: 2.9 lb-NOx (as NO2)/startup; 18.9 lb-CO/startup; or 2.1 lb-VOC(as methane)/startup. [District Rule 2201]
9. During shutdown of the unit, emissions shall not exceed any of the following limits: 0.5 lb-NOx (as NO2/shutdown; 5.6 lb-CO/shutdown; or 0.5 lb-VOC (as methane)/shutdown. [District Rule 2201]
10. NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.60 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 2.33 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]
11. PM10 emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.78 lb/hr or 0.016 lb/MMBtu. [District Rule 2201 and 40 CFR 60.43b(h)(i)]
12. SOx emissions (with or without the duct burner firing) shall not exceed 0.00285 lb/MMBtu. [District Rule 2201 and 40 CFR 60.4330]

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

13. NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) 2.5 ppmvd @ 15% O2 or 0.62 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 0.90 lb/hr; and VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]
14. PM10 emissions from this unit (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 1.07 lb/hr or 0.016 lb/MMBtu. [District Rule 2201]
15. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. 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]
16. The duration of each startup or shutdown shall not exceed 30 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]
17. The ammonia slip (NH3) emissions (with duct burner firing) shall not exceed either of the following limits: 2.23 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rule 2201]
18. The ammonia slip (NH3) emissions (without the duct burner firing) shall not exceed either of the following limits: 0.93 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rule 2201]
19. Annual emissions from the turbine and duct burner system (S-6534-3, as measured after the CO Catalyst and SCR Catalyst), including startup and shutdown emissions, shall not exceed any of the following limits: 14,138 lb-NOx (as NO2)/year; 19,999 lb-CO/year, 4,014 lb-VOC (as methane)/year; 4,335 lb-SOx (as SO2)/year; 19,999 lb-PM10/year, or 19,999 lb-NH3/year. All annual emissions limits are based on 12 consecutive month rolling emissions totals. [District Rule 2201]
20. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions totals to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201]
21. 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]
22. 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]
23. Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 120 days of startup (not including commissioning) and at least once every twelve months thereafter. [District Rules 2201, 4001, 4703, and 40 CFR 60.46]
24. Performance testing to measure the PM10 emissions (lb/hr) shall be conducted within 120 days of startup (not including commissioning). [District Rule 2201]
25. Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703]
26. The owner or operator shall be required to conform to the sampling facilities and testing procedures described in District Rule 1081 (as amended 12/16/93), Sections 3.0 and 6.1. [District Rule 1081]
27. The District must be notified 30 days prior to any performance testing and a test plan shall be submitted for District Approval 15 days prior to such testing. [District Rule 1081]
28. Performance testing shall be witnessed or authorized by District personnel. Test results must be submitted to the District within 60 days of performance testing. [District Rule 1081]

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

29. NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, 4001, and 4703]
30. VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules1081 and 2201]
31. CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703]
32. Source testing to measure PM10 emissions shall be conducted using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201]
33. Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081, 2201, and 4102]
34. The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4102]
35. Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rule 2201]
36. During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]
37. If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]
38. The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, and O2 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703]
39. If the NOx and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703]

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

40. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. [District Rule 4703]

41. The permittee shall provide notification and recordkeeping as required under 40 CFR, Part 60, Subpart A, 60.7. [District Rule 4001]

42. The facility shall maintain a record of the cumulate 12 month rolling NOx, CO, VOC, SOx, PM10, and NH3 emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201]

43. The facility shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201]

44. The sulfur fuel content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored weekly using ASTM Methods D4084, D5504, D6228, or Gas Processors Association Standard 2377. If the sulfur fuel content is less than 1.0 gr/100 scf for 8 consecutive weeks, then the monitoring frequency shall be every 6 months. If any six-month monitoring tests result in a sulfur fuel content exceedance, weekly monitoring shall resume. [40 CFR 60.4365]

45. Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. The permittee shall submit a detailed calculation protocol or monitoring plan for District Approval at least 60 days prior to the commencement of operation. [District Rules 2201 and 4102]

46. Permittee shall submit notification of the initial startup of the duct burner, as provided by 40 CFR Part 60 Section 60.7 to the EPA administrator. The notification shall include the design heat input capacity of the duct burner, identify the fuels to be combusted in the duct burner, and a copy of the performance test data from the initial performance tests for NOx emissions from the turbine and duct burner. [40 CFR 60.49b(b)]

47. All records shall be retained for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

Attachment B

BACT Guideline 3.4.3 and Top Down BACT Analysis

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.3*

Last Update 1/18/2005

Gas Turbine with Heat Recovery (= > 3 MW and = < 10 MW)

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmv @ 15% O2, based on a three-hour average (catalytic oxidation or equal)		
NOx	2.5 ppmv @ 15% O2, based on a three-hour average (selective catalytic reduction or equal)		
PM10	air inlet cooler, lube oil vent coalescer, and natural gas fuel		
SOx	PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with < 0.75 grains-S/100 dscf, or equal		
VOC	2.0 ppmv @ 15% O2, based on a three-hour average (catalytic oxidation 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 required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

1. NOx Top-Down BACT Analysis for Permit Unit S-6534-5-0

Step 1 – Identify all control technologies

SJVAPCD BACT Clearinghouse, Guideline 3.4.3, Gas Turbine with Heat Recovery (≥ 3 MW and ≤ 10 MW, 2nd quarter 2013, identifies BACT for NOx emissions as follows:

1) 2.5 ppmv @ 15% O2, based on a three-hour average (selective catalytic reduction or equal) (Achieved in Practice)

Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	2.5 ppmv @ 15% O2, based on a three-hour average (selective catalytic reduction or equal)	Y

There are no remaining control technologies for NOx.

Step 4 - Cost Effectiveness Analysis

This option listed above has been identified as achieved in practice for NOx emissions. Therefore, a cost analysis is not necessary.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the gas turbine must be satisfied with the following:

NO_X: 2.5 ppmv @ 15% O2, based on a three-hour average (selective catalytic reduction or equal) (Achieved in Practice)

The applicant has proposed to utilize an SCR system with the gas turbine system to reduce NO_X emissions to 2.5 ppmvd @ 15% O2, based on a three-hour average. Therefore, the BACT requirements are satisfied.

2. SOx Top-Down BACT Analysis for Permit Unit S-6534-5-0

Step 1 – Identify all control technologies

SJVAPCD BACT Clearinghouse, Guideline 3.4.3, Gas Turbine with Heat Recovery (≥ 3 MW and ≤ 10 MW, 2nd quarter 2013, identifies BACT for SOx emissions as follows:

1) PUC-regulated natural gas, LPG, or on-PUC-regulated natural gas with < 0.75 grains-S/100 scf, or equal (Achieved in Practice)

Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with < 0.75 grains-S/100 scf, or equal	Y

There are no remaining control technologies for SOx.

Step 4 - Cost Effectiveness Analysis

This option listed above has been identified as achieved in practice for SOx emissions. Therefore, a cost analysis is not necessary.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the gas turbine must be satisfied with the following:

SO_X: PUC-regulated natural gas, LPG, or on-PUC-regulated natural gas with < 0.75 grains-S/100 scf, or equal (Achieved in Practice)

The applicant has proposed to utilize PUC-regulated natural gas for the turbine and non-PUC-regulated natural gas with < 0.75 grains-S/100 scf for the duct burner. Therefore, the BACT requirements are satisfied.

3. PM_{10} Top-Down BACT Analysis for Permit Unit S-6534-5-0

Step 1 – Identify all control technologies

SJVAPCD BACT Clearinghouse, Guideline 3.4.3, Gas Turbine with Heat Recovery (≥ 3 MW and ≤ 10 MW, 2nd quarter 2013, identifies BACT for PM_{10} emissions as follows:

1) Air inlet cooler, lube oil vent coalescer, and natural gas fuel (Achieved in Practice)

Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	Air inlet cooler, lube oil vent coalescer, and natural gas fuel	Y

There are no remaining control technologies for PM_{10}.

Step 4 - Cost Effectiveness Analysis

This option listed above has been identified as achieved in practice for PM_{10} emissions. Therefore, a cost analysis is not necessary.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the gas turbine must be satisfied with the following:

PM_{10}: Air inlet cooler, lube oil vent coalescer, and natural gas fuel (Achieved in Practice)

The applicant has proposed to utilize an air inlet cooler or lube oil vent coalescer and natural gas fuel. Therefore, the BACT requirements are satisfied.

4. VOC Top-Down BACT Analysis for Permit Unit S-6534-5-0

Step 1 – Identify all control technologies

SJVAPCD BACT Clearinghouse, Guideline 3.4.3, Gas Turbine with Heat Recovery (≥ 3 MW and ≤ 10 MW, 2nd quarter 2013, identifies BACT for VOC emissions as follows:

1) 2.0 ppmv @ 15% O2, based on a three-hour average (catalytic oxidation or equal) (Achieved in Practice)

Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	2.0 ppmv @ 15% O2, based on a three-hour average (catalytic oxidation or equal)	Y

There are no remaining control technologies for VOC.

Step 4 - Cost Effectiveness Analysis

This option listed above has been identified as achieved in practice for VOC emissions. Therefore, a cost analysis is not necessary.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the gas turbine must be satisfied with the following:

VOC: 2.0 ppmv @ 15% O2, based on a three-hour average (catalytic oxidation or equal) (Achieved in Practice)

The applicant has proposed to utilize a catalytic oxidation system to reduce VOC emissions to 2.0 ppmvd @ 15% O2, based on a three-hour average. Therefore, the BACT requirements are satisfied.

Attachment C

Health Risk Assessment and Ambient Air Quality Analysis

Attachment D

Draft Authority to Construct Permits

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-6534-3-4 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: PIXLEY COGEN PARTNERS
MAILING ADDRESS: P O BOX 891
PIXLEY, CA 93256-0891

LOCATION: 11222 ROAD 120
PIXLEY, CA 93256

EQUIPMENT DESCRIPTION:
MODIFICATION OF 5.432 MW ELECTRIC POWER GENERATION SYSTEM (COMBINED CYCLE CONFIGURATION) CONSISTING OF A 67.1 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) SOLAR MODEL #TAURUS 65-8401S NATURAL GAS-FIRED COMBUSTION TURBINE WITH A 106.4 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) NATURAL GAS-FIRED DUCT BURNER, ALL SERVED BY A CO CATALYST AND A SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION: LIMIT COMBINED HEAT INPUT FOR DUCT BURNERS LISTED ON PERMITS S-6534-3 AND '5 TO 106.4 MMBTU/HR

CONDITIONS

1. 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]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine and duct burner. Exhaust ducting may be equipped (if required) with a fresh air inlet blower, to lower the exhaust temperature prior to the inlet of the SCR catalyst. [District Rule 2201]
6. The turbine/electrical generator shall be equipped with an air inlet filter and a lube oil vent coalescer (or equivalent). [District Rule 2201]
7. The duct burners listed in permits S-6534-3 and S-6534-5 shall not exceed a combined heat input limit of 106.4 MMBtu/hr (based on the higher heating value of natural gas). [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

DAVID WARNER, Director of Permit Services

S-6534-3-4 : Jul 8 2013 3:04PM – TOMS : Joint Inspection NOT Required

8. This unit shall be fired exclusively on PUC-regulated natural gas and the PUC-regulated natural gas shall have a total sulfur content of less than or equal to 1.0 gr/100 scf. [40 CFR 60.4330 and District Rules 2201 and 4801]

9. During startup of the unit, emissions shall not exceed any of the following limits: 2.9 lb-NOx (as NO2)/startup; 18.9 lb-CO/startup; or 2.1 lb-VOC(as methane)/startup. [District Rule 2201]

10. During shutdown of the unit, emissions shall not exceed any of the following limits: 0.5 lb-NOx (as NO2/shutdown; 5.6 lb-CO/shutdown; or 0.5 lb-VOC (as methane)/shutdown. [District Rule 2201]

11. NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.60 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 2.33 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]

12. PM10 emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.78 lb/hr or 0.016 lb/MMBtu. [District Rule 2201 and 40 CFR 60.43b(h)(i)]

13. SOx emissions (with or without the duct burner firing) shall not exceed 0.00285 lb/MMBtu. [District Rule 2201 and 40 CFR 60.4330]

14. NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) 2.5 ppmvd @ 15% O2 or 0.62 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 0.90 lb/hr; and VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201, 4001, 4703, 40 CFR 60.4320, and 40 CFR 60.44b(a)(4)(i)]

15. PM10 emissions from this unit (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 1.07 lb/hr or 0.016 lb/MMBtu. [District Rule 2201]

16. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. 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]

17. The duration of each startup or shutdown shall not exceed 30 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

18. The ammonia slip (NH3) emissions (with duct burner firing) shall not exceed either of the following limits: 2.23 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rule 2201]

19. The ammonia slip (NH3) emissions (without the duct burner firing) shall not exceed either of the following limits: 0.93 lb/hr or 10.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rule 2201]

20. Annual emissions from the turbine and duct burner system (S-6534-3, as measured after the CO Catalyst and SCR Catalyst), including startup and shutdown emissions, shall not exceed any of the following limits: 14,138 lb-NOx (as NO2)/year; 19,999 lb-CO/year, 4,014 lb-VOC (as methane)/year; 4,335 lb-SOx (as SO2)/year; 19,999 lb-PM10/year, or 19,999 lb-NH3/year. All annual emissions limits are based on 12 consecutive month rolling emissions totals. [District Rule 2201]

21. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions totals to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201]

22. 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]

23. 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]

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CONDITIONS CONTINUE ON NEXT PAGE

24. Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 120 days of startup (not including commissioning) and at least once every twelve months thereafter. [District Rules 2201, 4001, 4703, and 40 CFR 60.46]
25. Performance testing to measure the PM10 emissions (lb/hr) shall be conducted within 120 days of startup (not including commissioning). [District Rule 2201]
26. Any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [District Rule 4703]
27. The owner or operator shall be required to conform to the sampling facilities and testing procedures described in District Rule 1081 (as amended 12/16/93), Sections 3.0 and 6.1. [District Rule 1081]
28. The District must be notified 30 days prior to any performance testing and a test plan shall be submitted for District Approval 15 days prior to such testing. [District Rule 1081]
29. Performance testing shall be witnessed or authorized by District personnel. Test results must be submitted to the District within 60 days of performance testing. [District Rule 1081]
30. NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, 4001, and 4703]
31. VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules1081 and 2201]
32. CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703]
33. Source testing to measure PM10 emissions shall be conducted using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201]
34. Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081, 2201, and 4102]
35. The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4102]
36. Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rule 2201]
37. During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]
38. If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]

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CONDITIONS CONTINUE ON NEXT PAGE

39. The permittee shall monitor and record the stack concentration of NOx (as NO2), CO, and O2 weekly. If compliance with the NOx and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703]

40. If the NOx and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703]

41. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. [District Rule 4703]

42. The permittee shall provide notification and recordkeeping as required under 40 CFR, Part 60, Subpart A, 60.7. [District Rule 4001]

43. The facility shall maintain a record of the cumulate 12 month rolling NOx, CO, VOC, SOx, PM10, and NH3 emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201]

44. The facility shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201]

45. The sulfur fuel content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored weekly using ASTM Methods D4084, D5504, D6228, or Gas Processors Association Standard 2377. If the sulfur fuel content is less than 1.0 gr/100 scf for 8 consecutive weeks, then the monitoring frequency shall be every 6 months. If any six-month monitoring tests result in a sulfur fuel content exceedance, weekly monitoring shall resume. [40 CFR 60.4365]

46. Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. The permittee shall submit a detailed calculation protocol or monitoring plan for District Approval at least 60 days prior to the commencement of operation. [District Rules 2201 and 4102]

47. Permittee shall submit notification of the initial startup of the duct burner, as provided by 40 CFR Part 60 Section 60.7 to the EPA administrator. The notification shall include the design heat input capacity of the duct burner, identify the fuels to be combusted in the duct burner, and a copy of the performance test data from the initial performance tests for NOx emissions from the turbine and duct burner. [40 CFR 60.49b(b)]

48. {1958} All records shall be retained for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

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AUTHORITY TO CONSTRUCT

PERMIT NO: S-6534-5-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: PIXLEY COGEN PARTNERS
MAILING ADDRESS: P O BOX 891
PIXLEY, CA 93256-0891

LOCATION: 11222 ROAD 120
PIXLEY, CA 93256

EQUIPMENT DESCRIPTION:
5.67 MW ELECTRIC POWER GENERATION SYSTEM (COMBINED CYCLE CONFIGURATION), CONSISTING OF A 67.65 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) SOLAR MODEL #TAURUS60-7901S NATURAL GAS-FIRED COMBUSTION TURBINE WITH A 106.4 MMBTU/HR (BASED ON THE HIGHER HEATING VALUE OF NATURAL GAS) NATURAL GAS/BIOGAS-FIRED DUCT BURNER, ALL SERVED BY A CO CATALYST AND A RENTECH SELECTIVE CATALYTIC REDUCTION SYSTEM WITH AMMONIA INJECTION AND A HEAT RECOVERY STEAM GENERATOR

CONDITIONS

1. The owner/operator of the Pixley Cogeneration Plant shall minimize the emissions from the gas turbine system to the maximum extent possible during the commissioning period. Conditions #3 through #10 shall apply only during the commissioning period as defined below. Unless otherwise indicated, Conditions #11 through #63 shall apply after the commissioning period has ended. [District Rule 2201]
2. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the Pixley Cogeneration Plant construction contractor to ensure safe and reliable steady state operation of the gas turbine and associated electrical delivery systems. [District Rule 2201]
3. The commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the gas turbine is first fired, whichever comes first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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DAVID WARNER, Director of Permit Services
S-6534-5-0 : Jul 8 2013 3:04PM -- TOMS : Joint Inspection NOT Required

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

5. 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]

6. Coincident with the steady-state operation of the SCR system and the oxidation catalyst, NOx, CO, and VOC emissions from this unit shall comply with the limits specified in conditions #23 and #25. [District Rule 2201]

7. 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 of operation of the SCR system and the oxidation catalyst, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

8. Emissions rates from this unit, during the commissioning period, shall not exceed any of the following limits: NOx: 9.74 lb/hr (as NO2); SOx: 0.19 lb/hr (as SO2); PM10: 0.88 lb/hr; CO: 347.70 lb/hr; VOC: 7.53 lb/hr (as methane); or NH3: 0.45 lb/hr. [District Rule 2201]

9. The total number of firing hours for this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 96 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. The applicant shall keep a record of the number of hours the unit is fired without an abatement of emissions by the SCR system or the oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 96 firing hours without abatement shall expire. [District Rule 2201]

10. The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in condition #32. [District Rule 2201]

11. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

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

13. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

14. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

15. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

16. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine and duct burner. Exhaust ducting may be equipped (if required) with a fresh air inlet blower, to lower the exhaust temperature prior to the inlet of the SCR catalyst. [District Rule 2201]

17. The turbine/electrical generator shall be equipped with an air inlet filter and a lube oil vent coalescer (or equivalent). [District Rule 2201]

18. The duct burners listed in permits S-6534-3 and S-6534-5 shall not exceed a combined heat input limit of 106.4 MMBtu/hr (based on the higher heating value of natural gas). [District Rule 2201 and 4102]

19. The turbine shall be fired exclusively on PUC-regulated natural gas and the PUC-regulated natural gas shall have a total sulfur content of less than or equal to 1.0 gr/100 scf (equivalent to 1.97 ppmv in the exhaust). [District Rules 2201 and 4801 and 40 CFR 60.4330]

20. The duct burner shall be fired on PUC-regulated natural gas and/or biogas or any mixture thereof and shall have a total sulfur content of less than or equal to 0.75 gr/100 scf (equivalent to 1.48 ppmv in the exhaust). [District Rules 2201 and 4801 and 40 CFR 60.4330]

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CONDITIONS CONTINUE ON NEXT PAGE

21. During startup of the unit, emissions shall not exceed any of the following limits: 0.8 lb-NOx (as NO2)/startup; 78.5 lb-CO/startup; or 1.3 lb-VOC(as methane)/startup. [District Rule 2201]

22. During shutdown of the unit, emissions shall not exceed any of the following limits: 0.4 lb-NOx (as NO2/shutdown; 34.7 lb-CO/shutdown; or 0.5 lb-VOC (as methane)/shutdown. [District Rule 2201]

23. NOx, CO, and VOC emissions (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) - 2.5 ppmvd @ 15% O2 or 1.58 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 2.29 lb/hr; VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.44 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

24. PM10 emissions from this unit (with duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 2.26 lb/hr or 0.013 lb/MMBtu. [District Rule 2201]

25. NOx, CO, and VOC emissions rates (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst), except during periods of thermal stabilization or reduced load, shall not exceed any of the following limits: NOx (as NO2) 2.5 ppmvd @ 15% O2 or 0.61 lb/hr; CO - 6.0 ppmvd @ 15% O2 or 0.89 lb/hr; and VOC (as methane) - 2.0 ppmvd @ 15% O2 or 0.17 lb/hr. All emissions concentration limits are based on three hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320]

26. PM10 emissions from this unit (without duct burner firing and measured after the CO Catalyst and the SCR Catalyst) shall not exceed either of the following limits: 0.88 lb/hr or 0.013 lb/MMBtu. [District Rule 2201]

27. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its SCR operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. 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]

28. The duration of each startup or shutdown shall not exceed 30 minutes and 10 minutes respectively. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

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

30. The ammonia slip (NH3) emissions (with duct burner firing) shall not exceed either of the following limits: 1.16 lb/hr or 5.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]

31. The ammonia slip (NH3) emissions (without the duct burner firing) shall not exceed either of the following limits: 0.45 lb/hr or 5.0 ppmvd @15% O2 (based on a 24 hour rolling average). [District Rules 2201 and 4102]

32. Annual emissions from the turbine and duct burner system (S-6534-5, as measured after the CO Catalyst and SCR Catalyst), including startup and shutdown emissions, shall not exceed any of the following limits: NOx: 13,865 lb/year (as NO2); SOx: 3,684 lb/year (as SO2); PM10: 19,821 lb/year; CO: 21,507 lb/year; VOC: 3,872 lb/year (as methane); or NH3: 10,216 lb/year. All annual emissions limits are based on 12 consecutive month rolling emissions totals. [District Rule 2201]

33. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions totals to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201]

34. 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]

35. 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]

36. Performance testing to measure the NOx (ppmvd), CO (ppmvd), VOC (ppmvd), and NH3 (ppmvd) emissions shall be conducted within 120 days of startup (not including commissioning) and at least once every twelve months thereafter. [District Rules 2201, 4102, and 4703 and 40 CFR 60.4340 and 60.4400]

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37. Performance testing to measure the PM10 emissions (lb/hr) shall be conducted within 120 days of startup (not including commissioning). [District Rule 2201]

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

39. The owner or operator shall be required to conform to the sampling facilities and testing procedures described in District Rule 1081 (as amended 12/16/93), Sections 3.0 and 6.1. [District Rule 1081]

40. The District must be notified 30 days prior to any performance testing and a test plan shall be submitted for District Approval 15 days prior to such testing. [District Rule 1081]

41. Performance testing shall be witnessed or authorized by District personnel. Test results must be submitted to the District within 60 days of performance testing. [District Rule 1081]

42. NOx emissions (referenced as NO2) shall be determined using EPA Method 7E or EPA Method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR 60.4400. [District Rules 1081, 2201, and 4703 and 40 CFR 60.4400]

43. SOx emissions (referenced to SO2) shall be determined using EPA Methods 6, 6C, 8, 3A, 20, ASME PTC 19-10-1981-Part 10, or EPA Methods 1 and 2. [District Rules 1081 and 2201 and 40 CFR 60.4415]

44. VOC emissions (referenced as methane) shall be determined using EPA Method 18 or EPA Method 25. [District Rules 1081 and 2201]

45. CO emissions shall be determined using EPA Method 10 or EPA Method 10B. [District Rule 1081, 2201, and 4703]

46. PM10 emissions shall be determined using EPA Methods 201 and 202, or EPA Methods 201A and 202, or CARB Method 501 in conjunction with CARB Method 5. [District Rules 1081 and 2201]

47. Ammonia (NH3) emissions shall be determined using BAAQMD Method ST-1B. [District Rules 1081, 2201, and 4102]

48. The oxygen content of the exhaust gas shall be determined by using EPA Method 3, EPA Method 3A, or EPA Method 20. [District Rules 1081, 2201, and 4703]

49. HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [District Rule 4703]

50. Ammonia shall be injected whenever the selective catalytic reduction system catalyst temperature exceeds the minimum ammonia injection temperature recommended by the manufacturer. [District Rule 2201 and 4703]

51. During initial performance testing, the ammonia injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit (with or without the duct burner operating). The minimum ammonia injection rate(s) demonstrated during the initial performance test to result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rules 2201 and 4703]

52. If the ammonia injection rate is less than the minimum ammonia injection rate demonstrated during the initial compliance test, the permittee shall return the ammonia injection rate above the minimum ammonia injection rate established during compliance testing as soon as possible, but no longer than 8 hours after detection. If the ammonia injection rate is not returned above the minimum ammonia injection rate established during compliance testing within 8 hours, the permittee shall notify the District within the following 1 hour and conduct a source test within 60 days of the first exceedance to demonstrate compliance with the applicable emission limits at the reduced ammonia injection rate. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4703]

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CONDITIONS CONTINUE ON NEXT PAGE

53. The permittee shall monitor and record the stack concentration of NOx (as NO2), SOx (as SO2), CO, and O2 weekly. If compliance with the NOx, SOx, and CO emissions is demonstrated for eight (8) consecutive weeks, then the monitoring frequency will be reduced to monthly. If deviations are observed in two consecutive months, monitoring shall revert to weekly until 8 consecutive weeks show no deviations. Monitoring shall not be required if the unit is not in operation (i.e. the unit need not be started solely to perform monitoring). Monitoring shall be performed within one (1) day of restarting the unit unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the week if on a weekly monitoring schedule. [District Rules 2201 and 4703 and 40 CFR 60.4415]

54. If the NOx, SOx, and/or CO concentrations, as measured by the permittee with a portable analyzer, exceed the permitted emission limits, the permittee shall notify the District and return the NOx, SOx, and CO concentrations to the permitted emission limits as soon as possible but no longer than eight (8) hours after detection. If the permittee's portable analyzer readings continue to exceed the permitted emissions limits after eight (8) hours, the permittee shall notify the District within the following one (1) hour, and conduct a certified source test within 60 days to demonstrate compliance with the permitted emissions limits. In lieu of conducting a source test, the permittee may stipulate that a violation has occurred, subject to enforcement action. The permittee must correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4703 and 40 CFR 60.4415]

55. Compliance with ammonia emission limit shall be demonstrated utilizing one of the following procedures: 1) The permittee may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. 2) The permittee may utilize a District-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O2. The permittee shall submit a detailed calculation protocol or monitoring plan for District Approval at least 60 days prior to the commencement of operation. [District Rules 2201 and 4102]

56. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local start-up time and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. [District Rule 4703]

57. The permittee shall provide notification and recordkeeping as required under 40 CFR, Part 60, Subpart A, 60.7. [40 CFR 60.7]

58. The permittee shall maintain records of the amount of fuel combusted in the duct burners listed on permits S-6534-3 and S-6534-5 and calculated combined heat input. [District Rule 2201]

59. The permittee shall maintain a record of the cumulative 12 month rolling NOx, CO, VOC, SOx, PM10, and NH3 emissions total, in lb/year, from this unit. These records shall be updated at the end of each month. [District Rule 2201]

60. The permittee shall maintain a daily record of the ammonia injection rate and SCR catalyst inlet temperature. [District Rule 2201]

61. The owner or operator shall submit a written report of excess emissions and monitoring downtime 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 the cause of excess (if known), corrective actions taken and preventative measures adopted; Applicable time and date of each period during monitor downtime; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375 and 60.4395]

62. Permittee shall submit notification of the initial startup of the duct burner, as provided by 40 CFR Part 60 Section 60.7 to the EPA administrator. The notification shall include the design heat input capacity of the duct burner, identify the fuels to be combusted in the duct burner, and a copy of the performance test data from the initial performance tests for NOx emissions from the turbine and duct burner. [40 CFR 60.7]

63. All records shall be retained for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070, 2201, and 4703]

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AVISO DE UNA DECISION PRELIMINAR PARA LA PROPUESTA EMISION DE UNA AUTORIDAD PARA CONSTRUIR

POR EL PRESENTE SE NOTIFICA que El Distrito Unificado para el Control de la Contaminación del Aire del Valle de San Joaquín (el Distrito del Aire) está solicitando comentarios públicos en la propuesta emisión de una Autoridad para Construir a Pixley Cogen Partners para instalación de un 5.67 MW (ISO nominal) de un sistema de cogeneración de calor y electricidad combinado (CHP) consistiendo en una turbina de 67.65 MMBtu / hr de gas natural Modelo Solar Taurus 60 (T-60) y un quemador Rentech de 106.4 MMBtu/hr de gas natural / biogás como combustible con reducción catalítica selectiva (SCR) y catalizador de CO y el generador de vapor de recuperación de calor (HRSG) Rentech, en 11222 Road 120 en Pixley, CA.

El análisis de la base regulatoria para esta acción propuesta, Número del Proyecto #S-1131975, está disponible para la inspección pública en http://www.valleyair.org/notices/public_notices_idx.htm y en cualquiera de las oficinas del Distrito. Para más información en Español, por favor comuníquese con el Distrito al (559) 230-6000. Comentarios por escrito acerca de este proyecto deben ser sometidos antes del 5 de Septiembre del 2013 a **DAVID WARNER, DIRECTOR DEL DEPARTAMENTO DE PERMISOS, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

NOTICE OF PRELIMINARY DECISION FOR THE PROPOSED ISSUANCE OF AN AUTHORITY TO CONSTRUCT

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the proposed issuance of Authority to Construct to Pixley Cogen Partners for installation of one 5.67 MW (ISO rated) combined heat and power (CHP) cogeneration system consisting of one 67.65 MMBtu/hr natural gas-fired Solar Model Taurus 60 (T-60) turbine and one 106.4 natural gas/biogas-fired MMBtu/hr Rentech duct burner with Rentech selective catalytic reduction (SCR) and CO catalyst and Heat Recovery Steam Generator (HRSG), at 11222 Road 120 in Pixley, CA.

The analysis of the regulatory basis for this proposed action, Project #S-1131975, is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and at any District office. For additional information, please contact the District at (559) 230-6000. Written comments on this project must be submitted by September 5, 2013 to **DAVID WARNER, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY**

UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.