

NOV 16 2018

Gregory Stangl
North Fork Community Power
PO Box 30032
Walnut Creek, CA 94598

Re: Re-Notice of Preliminary Decision - Authority to Construct (Revised)
Facility Number: C-8980
Project Number: C-1160156

Dear Mr. Stangl:

Enclosed for your review and comment is the District's analysis of North Fork Community Power's application for Authorities to Construct (ATCs) for the installation of a 2.0 MW electrical generation facility based on forest waste biomass gasification process consisting of synthesis gas (syngas) conditioning equipment, two 1,631 bhp syngas-fired lean-burn IC engines with Selective Catalyst Reduction (SCR) system each powering an electrical generator, associated equipment, and a 14.5 MMBtu/hr syngas-fired backup flare, located at 57839 Road 225 in North Fork, CA.

This project was originally published for public notice on February 16, 2018 and ATCs C-8980-1-0 thru '3-0 were issued on March 20, 2018 after the 30-day public notice period was completed. However, after ATCs were issued you indicated that the location address provided with the ATC application was not correct and the correct location address should be 57839 Road 225 in North Fork, CA. The District also determined that the synthetic gas (syngas) F-factor of 7,648 dry standard cubic feet per million Btu (dscf/MMBtu) provided with the ATC application was not correct and the correct F-factor should be 12,100 dscf/MMBtu as calculated based on the syngas composition provided. In addition, maximum power ratings of the syngas IC engines need to be corrected from 1,572 bhp to 1,631 bhp based on the engine manufacturer's spec sheets. Therefore, ATCs C-8980-1-0 thru '3-0 will be revised and re-issued using the correct location address, correct F-factor for syngas, and correct maximum power ratings of the syngas-fired IC engines.

However, since these changes are considered significant, the project must be re-noticed for a 30-day public comment period prior to the issuance of the revised ATCs.

Samir Sheikh

Executive Director/Air Pollution Control Officer

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Mr. Stangl
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The revised 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 revised ATCs. 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. Sajjad Ahmad of Permit Services at (559) 230-5903.

Sincerely,

A handwritten signature in blue ink, reading "Arnaud Marjollet". The signature is written in a cursive style with a horizontal line underneath the name.

Arnaud Marjollet
Director of Permit Services

AM:sa

Enclosures

cc: Tung Le, CARB (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review (Revised)
2.0 MW Power Generation Operation based on Biomass Gasification

Facility Name: North Fork Community Power
Mailing Address: PO Box 29166
San Francisco, CA 94129-5700

Date: December 1, 2017
Revision Date: November 16, 2018
Engineer: Sajjad Ahmad
Lead Engineer: Joven Refuerzo

Contact: Gregory Stangl, Phoenix Energy
Telephone: (415) 286-7822
E-Mail: stangl@phoenixenergy.net

Application #s: C-8980-1-0 thru '-3-0
Project #: C-1160156
Deemed Complete: September 7, 2017

I. Proposal

Reasons for Revision:

As summarized in the original proposal below, this project was finalized and Authority to Construct (ATC) permits C-8980-1-0 thru '-3-0 were issued on March 23, 2018. However, after the ATCs were issued, the applicant stated that the location address of '59700 Road 225 in North Fork, CA' provided with the original ATC application was not correct and requested to correct the location address to '57839 Road 225 in North Fork, CA'.

In addition, the District determined that the synthetic gas (syngas) F-factor of 7,648 dry standard cubic feet per million Btu (dscf/MMBtu) provided by the applicant with the ATC application was not correct and the correct F-factor should be 12,100 dscf/MMBtu based on the syngas composition provided by the applicant (see Appendix H for F-factor calculation).

The District also noticed that the maximum power rating of 1,572 bhp of each of the two syngas fired IC engines provided by the applicant with the original ATC application was based on the electrical generator's power output. As indicated by the engine manufacturer's specification sheets, each engine has a slightly higher power rating of 1,633 bhp, which will be used to calculate revised potential emissions.

Therefore, ATCs C-8980-1-0 thru '-3-0 will be revised and re-issued using the correct location address, correct F-factor for syngas, and the correct power ratings of the engines. Since these changes are considered significant, the project will be re-noticed for a 30-day public comment period prior to the issuance of the revised ATCs. The original project proposal is as follows:

Original Proposal:

North Fork Community Power (herein after called 'the facility') has requested ATCs to install a new 2.0 MW electrical power generation operation that will utilize biomass gasification (pyrolysis) process to generate electricity for commercial sale. The proposal is summarized below:

ATCs C-8980-1-0 and '-2-0: The 2.0 MW electrical power generation operation will consist of two lines each with 1.0 MW electrical power generation capacity (ATCs '-1-0 and '-2-0). Each line will consist of a wood chips gasification unit (gasifier) to produce synthetic gas (syngas) by pyrolysis of wood chips from forest waste; a syngas conditioning system consisting of a cyclone, wet scrubbers, a cartridge type filter, and condensate traps; a 1,631 bhp lean-burn syngas-fired IC engine equipped with a Selective Catalyst Reduction (SCR) system and an oxidation catalyst powering an electrical generator; and a permit exempt cooling tower. The facility has also requested to allow the engines to be fired on propane or PUC-quality natural gas for up to 200 hours per year for maintenance and testing purposes and up to 200 hours during commissioning period when syngas is not available. The facility has stated that firing IC engines on alternate fuels will only be conducted when emissions control systems (SCR system and oxidation catalyst) are in operation. This will be enforced by appropriate permit conditions as discussed later in this evaluation.

ATC C-8980-3-0: A 14.5 MMBtu/hr syngas-fired backup flare to dispose of excess syngas produced from permit units '-1 and '-2 during periods of startup and shutdown, and when engines are temporarily out of service. No backup fuel is being proposed with the flare. Since the primary function of the backup flare is to dispose of excess syngas when IC engines are not in operation, it is not considered an emissions control device and instead is considered an emissions unit.

The draft ATCs are included in Appendix A.

The gasifiers will produce syngas by pyrolysis of a variety of biomass feedstock, which are described in California Public Resources Code Section 40106(a). This section defines the process of 'biomass conversion' as the production of heat, fuels, or electricity by the controlled combustion of, or the use of other noncombustion thermal conversion technologies on, the following materials, when separated from other solid waste:

- (1) Agricultural crop residues.
- (2) Bark, lawn, yard, and garden clippings.
- (3) Leaves, silvicultural residue, and tree and brush pruning.
- (4) Wood, wood chips, and wood waste.
- (5) Nonrecyclable pulp or nonrecyclable paper materials.

In addition, Title 14 of the California Code of Regulations, Section 18720 (84), defines wood waste as solid waste consisting of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. The District has determined that, for the purpose of defining permissible biomass feedstock for this process, the proposed process qualifies as a biomass conversion process. Therefore, the following condition will be listed on ATCs '-1-0 and '-2-0 to ensure compliance:

- The syngas fuel for this engine shall be generated in the gasifier from the following list of biomass feed stocks: (1) Agricultural crop residues; (2) Bark, lawn, yard, and garden clippings; (3) Leaves, silvicultural residue, and tree and brush pruning; (4) Wood, wood chips, and wood waste. Wood waste is defined as solid waste consisting of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. Biomass feed stocks used in the gasifier shall not have been treated with or contaminated by chemicals containing or contributing to the formation of hazardous air pollutants. [District Rules 2201 and 4102; California Public Resources Code 40106(a) and Title 14 California Code of Regulations Section 18720(84)]

II. Rules Applicable or Evaluated

Rule 2010 Permits Required (12/17/92)
Rule 2020 Exemptions (12/18/14)
Rule 2201 New and Modified Stationary Source Review Rule (2/18/16)
Rule 2410 Prevention of Significant Deterioration (6/16/11)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
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 4203 Particulate Matter Emissions from Incineration of Combustible Refuse (12/17/92)
Rule 4301 Fuel Burning Equipment (12/17/92)
Rule 4302 Incinerator Burning (12/16/93)
Rule 4311 Flares (6/18/09)
Rule 4702 Internal Combustion Engines (11/14/13)
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
California Code of Regulations, Title 14, Division 7, Chapter 9, Section 18720 (84)

III. Project Location

The facility is located at 57839 Road 225 in North Fork, CA. The District has verified that 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 primary function of this facility will be electrical power generation for commercial sale using two full-time syngas-fired IC engines. Biochar will also be produced as a by-product of the wood chips gasification process and will be sold commercially. The syngas will be produced in two gasifier units associated with each engine by pyrolysis of woody biomass received at the facility in the form of wood chips. Various steps of the operation are described below:

Permit Units C-8980-1-0 and -2-0: Electrical Generating Operations (#1 and 2):

a) Wood Chip Receiving and Storage Operation (Permit Exempt – Low Emitting Unit):

The main source of the woody biomass feedstock will be from various forest hazardous fuel treatment activities in the National Forests and local Fire Safety Councils in the North Fork area. It is expected that at least 80% of the biomass feedstock will be obtained from both private and public lands from activities such as fire threat reduction, fire safe clearances, infrastructure clearance, and other sustainable forest management activities. The facility may receive a maximum of 90 Bone Dry Tons (BDT) of woody biomass in the form of wood chips per day, pre-screened and sorted by size by various suppliers. The facility anticipates that as allowed by the local weather conditions, deliveries will take place only 8-9 months of the year, as the forest becomes increasingly inaccessible during winter months. Therefore, sufficient feedstock will be stored on-site in open windrows to allow the on-site activities to occur year-round, even when forests are not accessible. Front-end loaders will be used to move the wood chips from the windrows to a process feeding bin.

The wood chips are expected to contain high moisture content upon arrival as much as 50%. Therefore, wood chips may need to be dried in a rotary drum dryer to remove excess moisture. An inclined belt will move the chips from the bin to the rotary dryer. As discussed under Rule 2020 in Section VIII of this document and calculated in Appendix G, uncontrolled PM₁₀ emissions from the wood chips receiving and storage operation are less than two pounds per day. Therefore, these operations are exempt from District permits at this time and will be addressed under a separate cover letter.

b) Wood Chips Drying Operation (Permit Exempt – Low Emitting Unit):

Since wood chips will be stored on-site in open windrows in an area of high average precipitation, it may be necessary remove excess moisture before feeding into the gasifiers. A rotary drum dryer will be used to dry wood chips to 5 – 10% moisture. The dryer will use excess heat from engines' exhaust so no additional products of combustion are created in this step. In addition, the 'dried' wood chips will still have sufficient moisture to minimize any particulate emissions. Only one rotary drum dryer will be used to serve both electrical generation lines. As discussed under Rule 2020 in Section VIII of this document and calculated in Appendix G, uncontrolled PM₁₀ emissions from the wood chips drying operation are less than two pounds per day. Therefore, this operation is exempt from District permits at this time and will be addressed under a separate cover letter.

c) Biomass Gasification (Pyrolysis):

The dried wood chips will be transferred to the gasifiers using a belt conveyor and a bucket elevator. In the gasifiers, the wood chips will be converted into synthetic gas (syngas) and solid biochar through pyrolysis, a thermo-chemical process conducted in a controlled-temperature, low-oxygen environment. Since the wood chips will not be combusted in this process, the normal products of combustion will not be produced. During initial start-up, some of the wood chips may be burned using oil soaked rags to provide thermal energy. Once the reaction is established, the heat released by pyrolysis would be sufficient to sustain the reaction and the excess air blowers will be turned down to restrict available oxygen and extinguish the burning chips.

The produced syngas will be composed primarily of hydrogen (~ 19%), methane (~ 2%), and carbon monoxide (~ 19%), and will be piped to the downstream syngas conditioning system to be cleaned of entrained solids, tars, and other contaminants. The cleaned syngas will then be used as fuel for the IC engines powering the electrical generators.

d) Syngas Fuel Conditioning System

The produced syngas will be cleaned in a syngas conditioning system, which consists of a cyclone, three wet scrubbers, and a cartridge type filter operating in series. The syngas treatment process will begin when the syngas is initially vented through the biochar layer in the gasification chambers, which acts as a particulate filter to remove larger particulates. After gasifiers, syngas will first pass through a cyclone to separate any entrained particulates and then through the sprinkler type wet scrubbers and a cartridge filter in series before fed to the IC engines or combusted in the backup flare. The first two scrubbers will clean and cool syngas using water from the cooling towers. The last scrubber will use chilled water to further clean and cool syngas to the desired temperature. A cartridge type filter will be used for final polishing of the syngas prior to be used as fuel in the IC engines.

e) Electrical Power Generation

The cleaned/filtered syngas will be piped to the two IC engines, which will drive the electrical generators. The electrical power generated will be fed directly into the power distribution system. Exhaust from the engine will pass through oxidation catalyst and SCR system before venting to the atmosphere or some passing through the rotary dryer.

f) Condensate Processing and Water Treatment

The scrubbing water used to treat the syngas will be recirculated and will be partially filtered to remove impurities. When the impurities are too concentrated, the contaminated water will be containerized and disposed of as Hazardous Waste. The recirculating water will be cooled with a cooling tower associated with each electrical power generating line. Each cooling tower has a maximum circulation rate of 1,321 gallons per minute. Section 6.2 of District Rule 2020 (Exemptions), exempts water cooling towers with circulation rates of 10,000 gallons/minute and which are not used to cool process water or water from barometric jets or barometric condensers.

g) Biochar Handling (Enclosed System not subject to Permit)

The biochar will be approximately 6% to 9% of the initial weight of biomass feedstock. The biochar will be conveyed from the bottom of the gasifiers' conversion chambers into an enclosed, water-cooled auger to a hopper. The hopper will drop the biochar into two (2) cubic yard Super Sacks, which will be fabric bags that will be filled and emptied through an integral spout. Biochar is primarily carbon and can be used as a fertilizer or soil amendment. The Super Sacks will be moved by forklift to a warehouse, where they will be stored until sold and trucked offsite. As discussed under Rule 2010 in Section VIII of this document, the biochar handling system is fully enclosed, so this operation is not considered a source of air contaminants emissions and is not required to have a District permit at this time.

C-8980-3-0 (Backup Flare):

One 14.5 MMBtu/hr syngas-fired open type flare will serve both electrical generation lines. The flare will be used as a backup during the engines' initial start-up periods to flare off first runs of syngas, which will be lower quality fuel and could negatively affect the engines. Flare will also be used to dispose of excess syngas when the engines are undergoing maintenance or during emergency shutdown. The gasification process will require about five hours to fully shutdown the pyrolysis reaction. No supplemental fuel is proposed with the flare.

V. Equipment Listing

C-8980-1-0: 1.0 MW ELECTRICAL POWER GENERATION OPERATION (#1) UTILIZING BIOMASS GASIFICATION (PYROLYSIS) PROCESS CONSISTING OF THE FOLLOWING: A GE MODEL 1200 KG WOOD CHIPS GASIFIER; SYNTHETIC GAS (SYNGAS) CONDITIONING SYSTEM INCLUDING A CYCLONE, WET SCRUBBERS, A FILTER, AND CONDENSATE TRAPS; A 1,631 BHP GE JENBACHER MODEL JMS 612 F62 SYNGAS-FIRED LEAN-BURN IC ENGINE (#1) WITH A STEULER MODEL DENOX-J612F62/1 SELECTIVE CATALYTIC REDUCTION (SCR) AND AN OXIDATION CATALYST POWERING AN ELECTRICAL GENERATOR; AND ONE PERMIT EXEMPT COOLING TOWER (LESS THAN 10,000 GALLONS PER MINUTE) (REVISED 11/16/18)

C-8980-2-0: 1.0 MW ELECTRICAL POWER GENERATION OPERATION (#2) UTILIZING BIOMASS GASIFICATION (PYROLYSIS) PROCESS CONSISTING OF THE FOLLOWING: A GE MODEL 1200 KG WOOD CHIPS GASIFIER; SYNTHETIC GAS (SYNGAS) CONDITIONING SYSTEM INCLUDING A CYCLONE, WET SCRUBBERS, A FILTER, AND CONDENSATE TRAPS; A 1,631 BHP GE JENBACHER MODEL JMS 612 F62 SYNGAS-FIRED LEAN-BURN IC ENGINE (#2) WITH A STEULER MODEL DENOX-J612F62/1 SELECTIVE CATALYTIC REDUCTION (SCR) AND AN OXIDATION CATALYST POWERING AN ELECTRICAL GENERATOR; AND ONE PERMIT EXEMPT COOLING TOWER (LESS THAN 10,000 GALLONS PER MINUTE) (REVISED 11/16/18)

C-8980-3-0: 14.5 MMBTU/HR SYNGAS-FIRED BACKUP FLARE FOR DISPOSAL OF SYNGAS PRODUCED FROM PERMIT UNITS C-8980-1 AND -2 (REVISED 10/31/18)

VI. Emission Control Technology Evaluation

Each biomass gasification unit will be a fully enclosed chamber maintained under negative pressure by a syngas blower, thus eliminating fugitive syngas emissions. All syngas produced will pass through a syngas conditioning system consisting of a cyclone, wet scrubbers, a filter and condensate traps. These controls are expected to remove most of the particulates and condensable from the produced syngas. Since the entire syngas handling system is completely enclosed, syngas emissions are not evaluated under this project. Therefore, this project will evaluate emissions only from both IC engines stacks and the flare.

C-8980-1-0 and '2-0 (Syngas-Fired IC Engines):

Emissions from syngas-fired engines include NO_x, SO_x, PM₁₀, CO, and VOC. The proposed engines will use the following emission controls:

- Turbocharger
- Intercooler
- Positive Crankcase Ventilation (PCV)
- Air/Fuel Ratio or an O₂ Controller
- Lean-Burn Technology
- Selective Catalytic Reduction (SCR)
- Oxidation Catalyst
- Syngas Fuel Conditioning

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

The intercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_x.

The PCV system reduces crankcase VOC and PM₁₀ emissions by at least 90% over an uncontrolled crankcase vent.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize engine operation and catalyst function.

NO_x is the major pollutant of concern when burning syngas. NO_x formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_x) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_x). Due to the low fuel nitrogen content of syngas, nearly all NO_x emissions are thermal NO_x. Formation of thermal NO_x is affected by four combustion zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

Lean-burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_x formation.

In addition, each engine will be equipped with a Selective Catalytic Reduction (SCR) system and an oxidation catalyst. A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, are passed through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it is converted to ammonia. The ammonia is used to reduce NO_x, over the catalyst bed, to form elemental nitrogen and other by-products. The use of a catalyst typically reduces the NO_x emissions by up to 90%.

The oxidation catalyst will be used to convert CO and VOC emissions to CO₂ and water. This catalyst will be located prior to the urea solution injection site since the oxidation catalyst would otherwise convert the excess ammonia into NO_x.

The facility is proposing a syngas conditioning system prior to being used as fuel in the IC engines or combusted in the backup flare. The conditioning system consists of a cyclone, wet scrubbing system, and a cartridge type filter. These controls are expected to remove most of the particulates and condensables. Therefore, particulates and fuel sulfur contents of the treated syngas is expected to be very low, thus minimizing SO_x and PM₁₀ emissions from the IC engines.

C-8980-3-0 (Backup Flare):

Per applicant, the flare is open type with smokeless operation and will be designed for a thorough air/fuel mixing. This will lower flame temperature to minimize NO_x emissions and at the same time will promote complete combustion thus reducing VOC emissions. In addition, prior to incinerating in the flare, the syngas will be treated in a syngas conditioning system consisting of a cyclone and wet scrubbers. These controls are expected to remove most particulates and soluble, thus reducing SO_x and PM₁₀ emissions.

Furthermore, as discussed in the BACT section, the flare will be required to have visible emissions less than Ringelmann ¼ or 5% opacity, except for period(s) not exceeding three minutes in any one hour.

VII. General Calculations

A. Assumptions

To streamline emission calculations, PM_{2.5} emissions are assumed to be equal to PM₁₀ emissions. Only if needed to determine if a project is a Federal major modification for PM_{2.5} will specific PM_{2.5} emission calculations be performed.

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

- Syngas emissions are not evaluated under this project, since each biomass gasification unit will be a fully enclosed chamber maintained under negative pressure by a syngas blower, thus eliminating fugitive syngas emissions. In addition, the facility has stated that they will produce only enough syngas that would be handled by the syngas fired IC engines and the backup flare.
- Since syngas emissions are not evaluated under this project, there is no need to quantify the amount of syngas produced by the pyrolysis of the biomass feedstock. For streamlining purpose, all emissions are calculated from the exhausts of the two syngas fired IC engines and the backup flare where syngas is used as fuel. However, in order to ensure that the facility does not exceed the system capacity, the total combined amount of all biomass feedstock used to generate syngas in the two gasifiers under permit units C-8980-1-0 and '-2-0 will be limited by a Specific Limiting Condition (SLC) of not to exceed 90 Bone Dry Ton (BDT) per day and 20,000 BDT per calendar year (per applicant).
- Syngas Higher Heating Value (HHV) = 137 Btu/scf (as calculated in Appendix H¹)
- Maximum gas flowrate to each engine = 64,819 scf/hr (per applicant)
- F-Factor for syngas = 12,100 dscf/MMBtu (as calculated in Appendix H)
- MMBtu/hr to bhp conversion 393.236 bhp-hr/MMBtu (District practice)
- Molar specific volume = 379.5 scf/lb-mol (60°F)
- Molecular weights:
NO_x (as NO₂) = 46 lb/lb-mol CO = 28 lb/lb-mol NH₃ = 17 lb/lb-mol
VOC (as CH₄) = 16 lb/lb-mol SO_x (as SO₂) = 64.06 lb/lb-mol
- Efficiency of the IC engines = 30% (District practice)
- Ammonia slip from SCR = 10 ppm @ 15% O₂ (per applicant)
- A commissioning period to perform testing, adjustment, tuning, and calibration of the IC engines without full operation of the SCR system will be allowed during initial startup of each engine. The duration of the commissioning period will not exceed 500 hours of

¹ The applicant has stated syngas HHV of 132 Btu/scf. However, in the absence of any available source test data, HHV is more accurately calculated as 137 Btu/scf based on the syngas composition provided by the applicant (see Appendix H).

operation of each engine without the SCR system installed and operating at its maximum efficiency (per applicant)

- The engines will be allowed to operate up to 500 hours during the initial installation and testing period for commissioning purposes only during the first year of operation
- During normal operation, after the commissioning period, each engine will operate 24 hours per day and 8,760 hours per year (worst case)
- Each engine will be allowed to operate on propane or PUC-quality natural gas up to 200 hours per year for maintenance and testing purposes and up to 200 hours during the commissioning period when syngas is not available.
- Average sulfur content of the treated syngas: 5 ppmv as H₂S (per applicant)

C-8980-3-0 (Backup Flare):

- The flare will be used as backup only to dispose of excess syngas.
- Maximum gas flowrate to flare = 105,944 scf/hr (per applicant)
- Syngas Higher Heating Value (HHV) = 137 Btu/sf (see Appendix H)
- Maximum heat input = $105,944 \text{ scf/hr} \times 137 \text{ Btu/sf} \times 1 \text{ MMBtu/hr}/1,000,000 \text{ Btu}$
= 14.5 MMBtu/hr
- The flare will be equipped with a fuel flow meter. (per applicant)
- Maximum daily operation of the flare is 24 hr/day. (per applicant)
- Maximum annual operation of the flare will be limited based on a maximum fuel usage of 105.9 million standard cubic feet per year (MMscf/year). This is equivalent to an operation of the flare for 1,000 hr/year on full load as calculated below (per applicant):

$$\begin{aligned}\text{Maximum Fuel Usage} &= 105,944 \text{ scf/hr} \times 1,000 \text{ hr/year} \\ &= 105,944,000 \text{ scf/year} \\ &= 105,944,000 \text{ scf/year} \times 1 \text{ MMscf}/1,000,000 \text{ scf} \\ &= 105.9 \text{ MMscf/year}\end{aligned}$$

B. Emission Factors (EFs)

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

1. Emission Factors when Fired on Syngas During the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent its damage. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.²

Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

Emission factors for NO_x, CO, and VOC during the commissioning period are based on the manufacturer's data prior to treatment with oxidation catalyst and SCR. Whereas, emission factors for SO_x, PM₁₀, and ammonia slip during commissioning period are same as the emission factors during the normal operation presented in the table on next page.

Emission Factors for Engines when Fired on Syngas (Commissioning Period)			
Pollutant	g/bhp-hr	ppmvd (@ 15%O₂)	Source
NO _x	1.0	--	Manufacturer's data
SO _x	0.02	5 ppmv in fuel gas	See table on next page for emission factors during normal operation
PM ₁₀	0.03	--	
CO	14.5	--	Manufacturer's data
VOC	0.43	--	Manufacturer's data
NH ₃	0.07	10 ppmvd	Per applicant (see conversion on next page)

² See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (see <http://texasalliance.org/wp-content/uploads/2013/11/Pollution-Standards-for-Engines.pdf>)

2. Emission Factors when Fired on Syngas during Normal Operation after the Commissioning Period:

Emission factors for NO_x, CO, and VOC during normal operation are based on manufacturer's data after treatment with oxidation catalyst and SCR. Emission factors for SO_x, PM₁₀, and ammonia slip during normal operation are same as the emission factors presented above during the commissioning period. All emission factors will be verified during initial source testing.

Emission Factors for Engines when Fired on Syngas (Normal Operation)			
Pollutants	ppmvd @ 15% O ₂	g/bhp-hr ⁽¹⁾	Source
NO _x	9	0.18	Proposed by the applicant
SO _x	5 ppmv in fuel gas ⁽²⁾	0.02 ⁽³⁾	
PM ₁₀	--	0.03 ⁽⁴⁾	
CO	100	1.22	
VOC	25	0.17	
NH ₃	10	0.07	

⁽¹⁾ Emission factors for NO_x, CO, VOC, and NH₃ converted from ppmvd to g/bhp-hr as follows:

$$\frac{9 \text{ parts-NO}_x}{10^6 \text{ parts}} \times \frac{12,100 \text{ ft}^3}{1 \text{ MMBtu}} \times \frac{46 \text{ lb-NO}_x}{1 \text{ lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3} \times \frac{\text{MMBtu}}{393.236 \text{ bhp-hr}} \times \frac{453.59 \text{ g-NO}_x}{\text{lb-NO}_x} \times \frac{\text{Btu}_{\text{in}}}{0.30 \text{ Btu}_{\text{out}}} = 0.18 \frac{\text{g-NO}_x}{\text{bhp-hr}}$$

$$\frac{100 \text{ parts-CO}}{10^6 \text{ parts}} \times \frac{12,100 \text{ ft}^3}{1 \text{ MMBtu}} \times \frac{28 \text{ lb-CO}}{1 \text{ lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3} \times \frac{\text{MMBtu}}{393.236 \text{ bhp-hr}} \times \frac{453.59 \text{ g-CO}}{\text{lb-NO}_x} \times \frac{\text{Btu}_{\text{in}}}{0.30 \text{ Btu}_{\text{out}}} = 1.22 \frac{\text{g-CO}}{\text{bhp-hr}}$$

$$\frac{25 \text{ parts-VOC}}{10^6 \text{ parts}} \times \frac{12,100 \text{ ft}^3}{1 \text{ MMBtu}} \times \frac{16 \text{ lb-VOC}}{1 \text{ lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3} \times \frac{\text{MMBtu}}{393.236 \text{ bhp-hr}} \times \frac{453.59 \text{ g-VOC}}{\text{lb-NO}_x} \times \frac{\text{Btu}_{\text{in}}}{0.30 \text{ Btu}_{\text{out}}} = 0.17 \frac{\text{g-VOC}}{\text{bhp-hr}}$$

$$\frac{10 \text{ parts-NH}_3}{10^6 \text{ parts}} \times \frac{12,100 \text{ ft}^3}{1 \text{ MMBtu}} \times \frac{17 \text{ lb-NH}_3}{1 \text{ lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3} \times \frac{\text{MMBtu}}{393.236 \text{ bhp-hr}} \times \frac{453.59 \text{ g-NH}_3}{\text{lb-NO}_x} \times \frac{\text{Btu}_{\text{in}}}{0.30 \text{ Btu}_{\text{out}}} = 0.07 \frac{\text{g-NH}_3}{\text{bhp-hr}}$$

⁽²⁾ The applicant has stated a sulfur content of zero grain per 100 standard cubic feet (gr/100 scf) of the treated syngas. However, for a margin of compliance, 5 ppmv as H₂S will be used for the fuel sulfur content as the worst case.

⁽³⁾ Fuel sulfur content converted from ppmv to g-SO_x/bhp-hr as follows:

$$\frac{5 \text{ parts-H}_2\text{S}}{10^6 \text{ parts}} \times \frac{32.06 \text{ lb-S}}{\text{lb-mole H}_2\text{S}} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3} \times \frac{64.06 \text{ lb-SO}_x}{32.06 \text{ lb-S}} \times \frac{\text{ft}^3}{137 \text{ Btu}} \times \frac{10^6 \text{ Btu}}{\text{MMBtu}} = 0.0062 \frac{\text{lb-SO}_x}{\text{MMBtu}}$$

$$0.0062 \frac{\text{lb-SO}_x}{\text{MMBtu}} \times \frac{\text{MMBtu}}{393.236 \text{ bhp-hr}} \times \frac{\text{Btu}_{\text{in}}}{0.30 \text{ Btu}_{\text{out}}} \times \frac{453.59 \text{ g-SO}_x}{\text{lb-SO}_x} = 0.02 \frac{\text{g-SO}_x}{\text{bhp-hr}}$$

⁽⁴⁾ Manufacturer has stated a PM₁₀ emission factor of 0.03 g/bhp-hr at engines' outlet, which is similar to AP-42, Table 3.2-2 emission factor for natural gas-fired IC engines. Since syngas will be treated in the syngas conditioning system before used as fuel in the engines, the treatment is expected to remove most of the particulates and the use of clean syngas is expected to result in minimum PM₁₀ emissions. However, since no source test data is available to support the use of this emission factor, compliance demonstration with this emission factor will be required during initial source testing.

3. Alternate Fuels Emission Factors (PUC-Quality Natural Gas or Propane):

The facility has also requested to allow the engines to be fired on PUC-quality natural gas or propane for up to 200 hours per year for maintenance and testing purposes and up to 200 hours during commissioning period when syngas is not available. The facility has stated that the alternate fuels (PUC-quality natural gas or propane) will only be used when emissions control systems (SCR system and oxidation catalyst) are in operation to minimize emissions including the commissioning period. This will be enforced by appropriate permit conditions as discussed later in this evaluation.

Since emission controls will be in place, NO_x, CO, and VOC emissions will be considered controlled and same emission factors will be used as during normal operation as stated in last section.

Alternate Fuel Emission Factors (PUC-Quality Natural Gas or Propane)		
Pollutant	g/bhp-hr	Source
NO _x	0.18	Same as during normal operation
SO _x	0.012 ⁽¹⁾	District Practice for propane fired IC engines based on CARB Emissions Inventory Database
PM ₁₀	0.175 ⁽²⁾	
CO	1.22	Same as during normal operation
VOC	0.17	
NH ₃	0.07	

⁽¹⁾ For PUC-quality natural gas-fired IC engines, the District practice is to use an emission factor of 0.0094 g/bhp-hr or 0.00285 lb/MMBtu based on District Policy APR-1720, *Generally Accepted SO_x Emission Factor for Combustion of PUC-quality Natural Gas* (12/20/2001). For propane-fired IC engines, District practice is to use SO_x emission factor of 0.012 g/bhp-hr based on CARB emission inventory database. Since propane emission factor is higher, it will be used to calculate worst-case emissions from the alternate fuels.

⁽²⁾ For natural gas-fired 4-stroke lean-burn IC engines, the District practice is to use an emission factor of 0.033 g/bhp-hr based on AP-42, Table 3.2-2 (7/00) (see Appendix B). This emission factor includes both both filterable (7.71×10^{-5} lb/MMBtu) and condensable (9.91×10^{-3} lb/MMBtu) emissions. However, no emission factor is available in AP-42 for propane-fired IC engines; therefore, District practice is to use PM₁₀ emission factor of 0.175 g/bhp-hr for propane fired IC engines based on CARB emission inventory database. Since PM₁₀ emission factor for propane is higher, it will be used to calculate worst-case emissions from alternate fuels.

Summary of IC Engine Emission Factors:

The following table summarizes emission factors for easy reference and comparison:

Summary of Emission Factors (g/bhp-hr)			
Pollutant	During Commissioning	Normal Operation (After Commissioning)	Alternate Fuels
NO _x	1.0	0.18	0.18
SO _x	0.02	0.02	0.012
PM ₁₀	0.03	0.03	0.175
CO	14.5	1.22	1.22
VOC	0.43	0.17	0.17
NH ₃	0.07	0.07	0.07

C-8980-3-0 (Backup Flare):

Syngas-Fired Flare Emission Factors		
Pollutant	lb/MMBtu	Source
NO _x	0.068	AP-42 (12/16), Table 13.5-1 (see Appendix B)
SO _x	0.0065	AP-42 (4/00), Table 3.1-2b (see Appendix B)
PM ₁₀	0.008	District Practice
CO	0.31	AP-42 (12/16), Table 13.5-2 (see Appendix B)
VOC	0.063	District Practice

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since these are new emissions units, PE1 = 0 for all pollutants.

2. Post Project Potential to Emit (PE2)

C-8980-1-0 and -2-0 (Syngas-Fired IC Engines):

Since both syngas-fired IC engines are identical, the following calculations will be shown only for one IC engine for streamlining purpose.

Daily PE2:

Daily PE2 for Each IC Engine during the Commissioning Period:

Daily PE2 for the proposed engines during commissioning period is calculated using the following equation and summarized in the following table:

$$PE2 \text{ (lb/day)} = [EF \text{ (g/hp-hr)} \times \text{Rating (bhp)} \times 24 \text{ (hr/day)}] / 453.59 \text{ (g/lb)}$$

Daily PE2 During the Commissioning Period (each engine)								
NO _x	1.0	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	86.3	(lb/day)
SO _x	0.02	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	1.7	(lb/day)
PM ₁₀	0.03	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	2.6	(lb/day)
CO	14.5	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	1,251.3	(lb/day)
VOC	0.43	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	37.1	(lb/day)
NH ₃	0.07	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	6.0	(lb/day)

Daily PE2 for Each Engine after Completion of the Commissioning Period:

Daily PE2 for the proposed engines after completion of the commissioning period is calculated using the following equation in the table below:

$$\text{PE2 (lb/day)} = [\text{EF (g/hp-hr)} \times \text{Rating (bhp)} \times 24 \text{ (hr/day)}] / 453.59 \text{ (g/lb)}$$

Daily PE2 After the Commissioning Period (Normal Operation) (each engine)								
NO _x	0.18	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	15.5	(lb/day)
SO _x	0.02	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	1.7	(lb/day)
PM ₁₀	0.03	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	2.6	(lb/day)
CO	1.22	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	105.3	(lb/day)
VOC	0.17	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	14.7	(lb/day)
NH ₃	0.07	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	6.0	(lb/day)

Daily PE2 for Each Engine when fired on Alternate Fuels (PUC-Quality Natural Gas or Propane):

Daily PE2 for the proposed engines when fired on alternate fuels are calculated using the following equation in the table below:

$$\text{PE2 (lb/day)} = [\text{EF (g/hp-hr)} \times \text{Rating (bhp)} \times 24 \text{ (hr/day)}] / 453.59 \text{ (g/lb)}$$

Daily PE2 when Fired on Alternate Fuels (PUC-Quality Natural Gas or Propane) (each engine)								
NO _x	0.18	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	15.5	(lb/day)
SO _x	0.012	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	1.0	(lb/day)
PM ₁₀	0.175	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	15.1	(lb/day)
CO	1.22	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	105.3	(lb/day)
VOC	0.17	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	14.7	(lb/day)
NH ₃	0.07	(g/hp-hr) x	1,631	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	6.0	(lb/day)

Maximum Daily PE2 from Each Engine:

Daily PE2 is summarized in the following table during and after commissioning and when fired on alternate fuels. The maximum daily PE2 values for each pollutant will be selected in the last column for BACT purposes:

Daily PE2 with Commissioning (Each Engine)				
Pollutant	During Commissioning	After Commissioning	Alternate Fuels	Maximum Daily PE2
NO _x	86.3	15.05	15.5	86.3
SO _x	1.7	1.7	1.0	1.7
PM ₁₀	2.6	2.6	15.1	15.1
CO	1,251.3	105.3	105.3	1,251.3
VOC	37.1	14.7	14.7	37.1
NH ₃	6.0	6.0	6.0	6.0

Annual PE2:

First Year Annual PE2 Including Commissioning Period and Alternate Fuel Firing:

As discussed above, each of the proposed engines will be allowed to operate up to 500 hours for commissioning during the first year of operation. In addition, the facility has requested to use alternate fuels (PUC-quality natural gas or propane) for 200 hours each year including during commissioning period. The maximum annual PE2 for the first year for each engine will be calculated based on 500 hours of commissioning period, 200 hours of alternate fuel firing, and the remaining 8,060 hours during normal operation as summarized in the following tables:

Annual PE2 During the Commissioning Period (Each Engine)								
NO _x	1.0	(g/hp-hr) x	1,631	(bhp) x	500	(hr/year) ÷ 453.59 (g/lb) =	1,798	(lb/yr)
SO _x	0.02	(g/hp-hr) x	1,631	(bhp) x	500	(hr/year) ÷ 453.59 (g/lb) =	36	(lb/yr)
PM ₁₀	0.03	(g/hp-hr) x	1,631	(bhp) x	500	(hr/year) ÷ 453.59 (g/lb) =	54	(lb/yr)
CO	14.5	(g/hp-hr) x	1,631	(bhp) x	500	(hr/year) ÷ 453.59 (g/lb) =	26,069	(lb/yr)
VOC	0.43	(g/hp-hr) x	1,631	(bhp) x	500	(hr/year) ÷ 453.59 (g/lb) =	773	(lb/yr)
NH ₃	0.07	(g/hp-hr) x	1,631	(bhp) x	500	(hr/year) ÷ 453.59 (g/lb) =	126	(lb/yr)

Annual PE2 when Fired on Alternate Fuels (Each Engine)								
NO _x	0.18	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	129	(lb/yr)
SO _x	0.012	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	9	(lb/yr)
PM ₁₀	0.175	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	126	(lb/yr)
CO	1.22	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	877	(lb/yr)
VOC	0.17	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	122	(lb/yr)
NH ₃	0.07	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	50	(lb/yr)

First Year Annual PE2 After the Commissioning Period when Fired on Syngas (Each Engine)								
NOx	0.18	(g/hp-hr) x	1,631	(bhp) x	8,060	(hr/year) ÷ 453.59 (g/lb) =	5,217	(lb/yr)
SOx	0.02	(g/hp-hr) x	1,631	(bhp) x	8,060	(hr/year) ÷ 453.59 (g/lb) =	580	(lb/yr)
PM ₁₀	0.03	(g/hp-hr) x	1,631	(bhp) x	8,060	(hr/year) ÷ 453.59 (g/lb) =	869	(lb/yr)
CO	1.22	(g/hp-hr) x	1,631	(bhp) x	8,060	(hr/year) ÷ 453.59 (g/lb) =	35,358	(lb/yr)
VOC	0.17	(g/hp-hr) x	1,631	(bhp) x	8,060	(hr/year) ÷ 453.59 (g/lb) =	4,927	(lb/yr)
NH ₃	0.07	(g/hp-hr) x	1,631	(bhp) x	8,060	(hr/year) ÷ 453.59 (g/lb) =	2,029	(lb/yr)

First Year Total Annual PE2 from Each Engine:

First year total annual PE2 is calculated by adding PE2 of commissioning period, operation on alternate fuel, and normal operation as follows:

First Year Annual PE2 (lb/year)				
Pollutant	During Commissioning	Alternate Fuels	After Commissioning	Total Annual PE2
NOx	1,798	129	5,217	7,144
SOx	36	9	580	625
PM ₁₀	54	126	869	1,049
CO	26,069	877	35,358	62,304
VOC	773	122	4,927	5,822
NH ₃	126	50	2,029	2,205

Annual PE2 for Each Engine after First Year (No Commissioning):

Annual PE2 for the proposed engines after completion of the commissioning period is calculated using the following equation in the table below based on 8,560 hours of normal operation and 200 hours of firing on alternate fuels:

$$\text{PE2 (lb/year)} = [\text{EF (g/hp-hr)} \times \text{Rating (bhp)} \times \text{Operation (hr/year)}] / 453.59 \text{ (g/lb)}$$

Annual PE2 After Year 1 with no Commissioning (Normal Operation) (Each Engine)								
NOx	0.18	(g/hp-hr) x	1,631	(bhp) x	8,560	(hr/year) ÷ 453.59 (g/lb) =	5,540	(lb/yr)
SOx	0.02	(g/hp-hr) x	1,631	(bhp) x	8,560	(hr/year) ÷ 453.59 (g/lb) =	616	(lb/yr)
PM ₁₀	0.03	(g/hp-hr) x	1,631	(bhp) x	8,560	(hr/year) ÷ 453.59 (g/lb) =	923	(lb/yr)
CO	1.22	(g/hp-hr) x	1,631	(bhp) x	8,560	(hr/year) ÷ 453.59 (g/lb) =	37,551	(lb/yr)
VOC	0.17	(g/hp-hr) x	1,631	(bhp) x	8,560	(hr/year) ÷ 453.59 (g/lb) =	5,233	(lb/yr)
NH ₃	0.07	(g/hp-hr) x	1,631	(bhp) x	8,560	(hr/year) ÷ 453.59 (g/lb) =	2,155	(lb/yr)

Annual PE2 when Fired on Alternate Fuels (Each Engine)								
NOx	0.18	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	129	(lb/yr)
SOx	0.012	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	9	(lb/yr)
PM ₁₀	0.175	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	126	(lb/yr)
CO	1.22	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	877	(lb/yr)
VOC	0.17	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	122	(lb/yr)
NH ₃	0.07	(g/hp-hr) x	1,631	(bhp) x	200	(hr/year) ÷ 453.59 (g/lb) =	50	(lb/yr)

Total Annual PE2 after First Year (No Commissioning):

Total annual PE2 for each year, after the first year, is calculated by adding PE2 of 200 hours of operation on alternate fuel and remaining 8,560 hours of normal operation when fired on syngas in the following table:

Annual PE2 after Year 1 with no Commissioning – Normal Operation (lb/year)			
Pollutant	When Fired on Syngas	When Fired on Alternate Fuels	Total Annual PE2
NOx	5,540	129	5,669
SOx	616	9	625
PM ₁₀	923	126	1,049
CO	37,551	877	38,428
VOC	5,233	122	5,355
NH ₃	2,155	50	2,205

C-8980-3-0 (Backup Flare):

Daily and annual PE2 for flare are calculated using the following equations and summarized in the following table:

$$\text{Daily PE2} = \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/day)}$$

$$\text{Annual PE2} = \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/year)}$$

Syngas-fired Flare Potential Emissions (PE2)						
Pollutant	Rating (MMBtu/hr)	Emission Factor (lb/MMBtu)	Operation (hours/day)	Operation (hours/year)	Emissions (lb/day)	Emissions (lb/year)
NOx	14.5	0.068	24	1,000	23.7	986
SOx	14.5	0.0065	24	1,000	2.3	94
PM ₁₀	14.5	0.008	24	1,000	2.8	116
CO	14.5	0.31	24	1,000	107.9	4,495
VOC	14.5	0.063	24	1,000	21.9	914

The applicant has proposed to limit the maximum flare usage to 24 hr/day and 1,000 hr/year based on maximum syngas firing rate of 105,944 standard cubic feet per hour (scf/hr). In order to give a flexibility of operation, the equivalent annual fuel usage is calculated as follows:

$$\begin{aligned}\text{Maximum Fuel Usage} &= 105,944 \text{ scf/hr} \times 1,000 \text{ hr/year} \\ &= 105,944,000 \text{ scf/year} \\ &= 105,944,000 \text{ scf/year} \times 1 \text{ MMscf}/1,000,000 \text{ scf} \\ &= 105.9 \text{ MMscf/year}\end{aligned}$$

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

Pursuant to District Rule 2201, the 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 (AER) that have occurred at the source, and which have not been used on-site.

Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 is equal to zero.

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

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

Since potential emissions for each engine are higher during the first year, due to commissioning, than the normal operation in subsequent years, the emissions associated with the first year with commissioning will be used for NSR purposes.

Based on emission calculations in Section VII.C.2 above, SSPE2 is summarized in the following table:

SSPE2 (lb/year)						
Permit Unit	NOx	SOx	PM ₁₀	CO	VOC	NH3
C-8980-1-0 (engine #1)*	7,144	625	1,049	62,304	5,822	2,205
C-8980-2-0 (engine #2)*	7,144	625	1,049	62,304	5,822	2,205
C-8980-3-0 (flare)	986	94	116	4,495	914	0
SSPE2	15,274	1,344	2,214	129,103	12,558	4,410

*As calculated in Section VII.C.2 above, since first year's emissions are higher than the each subsequent year due to commission period, first year's emissions are selected for a worst case.

5. Major Source Determination

Rule 2201 Major Source Determination:

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	PM _{2.5}	CO	VOC
SSPE1	0	0	0	0	0	0
SSPE2	15,274	1,344	2,214	2,214	129,103	12,558
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No	No

Note: PM_{2.5} assumed to be equal to PM₁₀

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)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO ₂	VOC	SO ₂	CO	PM	PM ₁₀
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	N	N	N	N	N

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/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 = PE1 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.

C-8980-1-0 thru '3-0:

Since these are new emissions units, BE = PE1 = 0 for all pollutants.

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.

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

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO₂ (as a primary pollutant)
- SO₂ (as a primary pollutant)
- CO
- PM
- PM₁₀

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

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). The PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO ₂	SO ₂	PM	PM ₁₀	CO	VOC
Total PE from New and Modified Units	7.6	0.7	1.1	1.1	64.6	6.3
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

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

VIII. Compliance Determination

Rule 2010 Permits Required

The purpose of this rule is to require any person constructing, altering, replacing or operating any source operation which emits, may emit, or may reduce emissions to obtain an Authority to Construct or a Permit to Operate. The provisions of this rule apply to any person who plans to or does operate, construct, alter, or replace any source operation, which may emit air contaminants or may reduce the emission of air contaminants.

As explained below, the biochar handling operation associated with this project is an enclosed system and will not be considered a source of air contaminants.

The biochar will be removed from the bottom of the gasification chambers and will be transferred by an enclosed, water-cooled auger to a hopper. The cooled biochar will be loaded into 2.0 cubic yard, fabric “super sacks” with integral spouts to prevent emissions and spillage during loading and unloading. After bagging, the super sacks will be moved using a forklift for storage. Since the whole biochar handling operation will be fully enclosed and all biochar will be packaged into the super sacks, no open handling will be involved so this operation is not considered a source of air contaminant emissions and a permit will not be required at this time.

Rule 2020 Exemptions

This rule specifies emissions units that are not required to obtain an Authority to Construct or Permit to Operate. The following equipment is exempt from permits as explained below:

Cooling Towers:

Section 6.2 states a permit exemption for cooling towers that have a water circulation rate of less than 10,000 gallons per minute, and that are not used for cooling of process water, water from barometric jets, or water from barometric condensers. Per applicant, each of the two cooling towers associated with each permit unit C-8980-1 and -2 has a maximum water circulation rate of 300 cubic meter per hour (equivalent to about 1,321 gallons per minute). In addition, no process water will be used; therefore, each cooling tower is exempt from District permits.

Low Emitting Units (Wood Chips Receiving, Storage, and Drying Operations):

Section 6.19 states that ‘Low Emitting Units’, except those which belong to a source category listed in Sections 6.1 through 6.18 shall not require an Authority to Construct or Permit to Operate. Section 3.10 defines a ‘Low Emitting Unit’ as an emissions unit with an uncontrolled emissions rate of each air contaminant, less than or equal to two pounds per day, or if greater than two pounds per day, is less than or equal to 75 pounds per year.

As calculated in Appendix G, uncontrolled potential emissions from each of the wood chips receiving, storage, and drying operations are less than two pounds per day; therefore, these operations are exempt from permits at this time.

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 an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

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

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

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

As calculated in Section VII.C.2 of this document, each of the two proposed new IC engines will have PE2 greater than 2.0 lb/day for NO_x, PM₁₀, CO, and VOC emissions. However, BACT is not triggered for CO emissions, since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document. Therefore, BACT is triggered for NO_x, PM₁₀, and VOC emission for each IC engine.

Each of the proposed IC engines will also have a PE2 greater than 2.0 lb/day for NH₃ emissions. However, NH₃ slip emissions result from operation of an emissions control device (SCR) and not the emissions unit by itself; therefore, this project does not trigger BACT for NH₃ emissions for the IC engines.

C-8980-3-0 (Backup Flare):

As discussed in Section I of this document, since the primary function of the backup flare is to dispose of excess syngas when IC engines are not in operation, it is not considered an emissions control device and instead is considered an emissions unit.

As calculated in Section VII.C.2 of this document, the proposed new syngas-fired flare will have PE2 greater than 2.0 lb/day for NO_x, SO_x, PM₁₀, CO, and VOC emissions. However, BACT is not triggered for CO emissions, since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document. Therefore, BACT is triggered for NO_x, SO_x, PM₁₀, and VOC emission for the flare.

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

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore BACT is not triggered.

d. SB 288/Federal Major Modification

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

2. BACT Guideline

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

The District's BACT Clearinghouse currently includes a BACT Guideline 3.3.14 for full-time syngas-fired rich-burn IC engines. However, no BACT Guideline currently exists for full-time syngas-fired lean-burn IC engines. Therefore, a new BACT determination will be made in order to address NO_x, PM₁₀, and VOC emissions from the full-time syngas-fired lean-burn IC engines. Since both rich-burn and lean-burn syngas-fired IC engines essentially belong to the same class and source category, no new BACT Guideline will be established, instead the current BACT Guideline 3.3.14 will be updated to address the lean-burn technology for streamlining purposes.

See Appendix D for BACT determination.

C-8980-3-0 (Backup Flare):

However, the District's BACT Clearinghouse currently does not include a BACT Guideline that could be applied to this class and category. In addition, all previous BACT Guidelines applicable to the flares have been rescinded and a new project specific BACT must be performed for new and modified flares with the goal to minimize flaring when possible and require low NO_x flares when feasible and cost effective. Therefore, a new BACT determination will be made for the syngas-fired flare associated with this project.

See Appendix E for new BACT determination.

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.

C-8980-1-0 and -2-0 (Syngas-Fired IC Engines):

Pursuant to the Top-Down BACT Analysis (see Appendix D), BACT has been satisfied with the following:

- NO_x: 9 ppmvd NO_x @ 15% O₂ (equivalent to 0.18 g/bhp-hr) with a lean-burn IC engine with SCR system
- PM₁₀: ≤ 0.03 g/bhp-hr with syngas conditioning system (wet scrubbers, cartridge filters, or equivalent) and Positive Crankcase Ventilation (PCV)
- VOC: 25 ppmvd VOC @ 15% O₂ (equivalent to 0.17 g/bhp-hr)

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

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 9 ppmvd NO_x @ 15% O₂ (NO_x referenced as NO₂) (equivalent to 0.18 g/bhp-hr); 0.03 g-PM₁₀/bhp-hr; 100 ppmvd CO @ 15% O₂ (equivalent to 1.22 g/bhp-hr); or 25 ppmvd VOC @ 15% O₂ (VOC referenced as CH₄) (equivalent to 0.17 g/bhp-hr). [District Rules 2201 and 4702]
- This engine shall only use syngas as fuel that has been treated in the syngas conditioning system. [District Rule 2201]
- {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system which recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]

C-8980-3-0 (Backup Flare):

Pursuant to the Top-Down BACT Analysis (see Appendix E), BACT has been satisfied with the following:

- NO_x: NO_x emissions ≤ 0.068 lb/MMBtu
- SO_x: SO_x emissions ≤ 0.0065 lb/MMBtu (wet scrubbing system)
- PM₁₀: PM₁₀ emissions ≤ 0.008 lb/MMBtu (visible emissions less than Ringelmann ¼ or 5% opacity, except for period(s) not exceeding three minutes in any one hour)
- VOC: VOC emissions ≤ 0.063 lb/MMBtu

Therefore, the following conditions will be listed on the ATC to ensure compliance with the BACT requirements:

- Emissions from this flare shall not exceed any of the following limits: 0.068 lb-NO_x/MMBtu, 0.0065 lb-SO_x/MMBtu, 0.008 lb-PM₁₀/MMBtu, 0.31 lb-CO/MMBtu, or 0.063 lb-VOC/MMBtu. [District Rules 2201 and 4801]
- This flare shall only incinerate syngas that has been treated in the wet scrubbing system. [District Rule 2201]
- 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 1/4 or 5% opacity. [District Rules 2201 and 4101]

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals 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
SSPE2	15,274	1,344	2,214	129,103	12,558
Offset Thresholds	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 the 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,
- d. Any project with an SSPE2 of greater than 20,000 lb/year for any pollutant, and/or
- e. Any project which results in a Title V significant permit modification

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 Sections 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 only new emission unit with this project with PE2 greater than 100 lb/day is the syngas fired flare. Daily PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

C-8980-1-0 and -2-0 (Syngas-Fired IC Engines):

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO _x	86.3	100 lb/day	No
SO _x	1.7	100 lb/day	No
PM ₁₀	15.1	100 lb/day	No
CO	1,251.3	100 lb/day	Yes
VOC	37.1	100 lb/day	No

Therefore, public noticing is required, as daily CO emissions from each IC engine are greater than 100 pounds per day.

C-8980-3-0 (Backup Flare):

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO _x	23.7	100 lb/day	No
SO _x	2.3	100 lb/day	No
PM ₁₀	2.8	100 lb/day	No
CO	107.9	100 lb/day	Yes
VOC	21.9	100 lb/day	No

Therefore, public noticing is required, as daily CO emissions from the flare are greater than 100 pounds per day.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NOx	0	15,274	20,000 lb/year	No
SOx	0	1,344	54,750 lb/year	No
PM ₁₀	0	2,214	29,200 lb/year	No
CO	0	129,103	200,000 lb/year	No
VOC	0	12,558	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 SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NOx	15,274	0	15,274	20,000 lb/year	No
SOx	1,344	0	1,344	20,000 lb/year	No
PM ₁₀	2,214	0	2,214	20,000 lb/year	No
CO	129,103	0	129,103	20,000 lb/year	Yes
VOC	12,558	0	12,558	20,000 lb/year	No

As demonstrated above, the SSIPEs for CO emissions were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating permit, this change is not a Title V significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project because daily CO emissions from both IC engines and flare are greater than 100 lb/day and SSIPe for CO is greater than 20,000 lb/year. 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 ATCs for this project.

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.

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

Feedstock DEL:

As discussed in Section VII.A of this document (assumptions), syngas emissions are not evaluated under this project and there is no need to quantify the amount of syngas produced by the pyrolysis of the biomass feedstock. However, in order to ensure that the facility does not exceed the system capacity, the following condition will be listed on both ATCs to limit the amount of biomass feedstock used to produce syngas:

- The combined total amount of all biomass feedstock used to generate syngas in the two gasifiers under permit units C-8980-1 and '-2 shall not exceed the following limits: 90 Bone Dry Ton (BDT) per day and 20,000 BDT per calendar year. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions for Each Engine during Both Commissioning and Normal Operation:

- This engine shall be fired on synthetic gas (syngas) fuel only, except for up to 200 hours per year for maintenance and testing purposes and up to 200 hours during commissioning period during which the engine could be fired on PUC-quality natural gas or propane. [District Rule 2201]
- When fired on PUC-quality natural gas or propane, Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be in operation. [District Rules 2201 and 4102]
- When fired on PUC-quality natural gas or propane, emissions from this unit shall not exceed any of the following limits: 0.18 g-NO_x/bhp-hr, 0.012 g-SO_x/bhp-hr, 0.175 g-PM₁₀/bhp-hr, 1.22 g-CO/bhp-hr, or 0.17 g-VOC/bhp-hr. [District Rule 2201]

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]
- Ammonia (NH₃) emissions from this engine shall not exceed 10 ppmvd @ 15% O₂. [District Rule 2201 and 4102]
- The sulfur content of the syngas used as fuel in this engine shall not exceed 5 ppmv as H₂S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
- All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For the proposed engines, the DELs for NO_x, SO_x, PM₁₀, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr), the maximum engine horsepower rating (1,631 bhp), and maximum number of hours allowed for commissioning activities. The following conditions will be listed on the ATCs to ensure compliance:

- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
- Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The total duration of the commissioning period for this engine shall not exceed 500 hours of operation of the engine. [District Rules 2201 and 4102]
- Commissioning period ends when either of the following two events occurs first: 1) 500 hours of operation of the engine as allowed during the commissioning period, or 2) the electrical generator associated with this engine has successfully demonstrated to generate a minimum of 800 kw of electric power for 72 continuous hours and the Selective Catalytic Reduction (SCR) system and the oxidation catalyst have completed the breaking-in period, as recommended by the manufacturer. The permittee shall submit any relevant data to the District to demonstrate the end of the commissioning period no later than 14 days after such demonstration is completed. [District Rule 2201]

- The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 500 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 or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 500 firing hours without abatement shall expire. [District Rule 2201]
- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the SCR system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
- The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
- Emission rates from this engine during the commissioning period shall not exceed any of the following limits: 1.0 g-NO_x/bhp-hr, 0.03 g-PM₁₀/bhp-hr, 14.5 g-CO/bhp-hr, 0.43 g-VOC/bhp-hr. [District Rule 2201]
- The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Normal Operation:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 9 ppmvd NO_x @ 15% O₂ (NO_x referenced as NO₂) (equivalent to 0.18 g/bhp-hr); 0.03 g-PM₁₀/bhp-hr; 100 ppmvd CO @ 15% O₂ (equivalent to 1.22 g/bhp-hr); or 25 ppmvd VOC @ 15% O₂ (VOC referenced as CH₄) (equivalent to 0.17 g/bhp-hr). [District Rules 2201 and 4702]
- Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]

C-8980-3-0 (Backup Flare):

- This flare shall be equipped with a non-resettable totalizing volumetric fuel meter. [District Rules 2201 and 4311]
- The total amount of syngas combusted in the flare shall not exceed 105.9 million standard cubic feet (MMscf) per year (equivalent to 1,000 hours of flare operation at full load). [District Rules 2201 and 4311]
- Emissions from this flare shall not exceed any of the following limits: 0.068 lb-NO_x/MMBtu, 0.0065 lb-SO_x/MMBtu, 0.008 lb-PM₁₀/MMBtu, 0.31 lb-CO/MMBtu, or 0.063 lb-VOC/MMBtu. [District Rules 2201 and 4801]

E. Compliance Assurance

1. Source Testing

C-8980-1-0 and -2-0 (Syngas-Fired IC Engines):

In accordance with District Policy APR 1705, *Source Testing Frequency (10/9/97)*, source testing for NO_x, CO and VOC emissions from the syngas fired IC engines served by a catalyst control system (including SCR and an oxidation catalyst) shall be conducted initially and at least once every 24 months thereafter. In addition, in order to assure compliance with the ammonia slip limit from the SCR system, source testing of the ammonia emissions will also be required initially and at least once every 24 months thereafter.

For PM₁₀ emissions, the applicant has proposed to use an emission factor, which is based on AP-42, Section 3.2-2 for natural gas fired IC engines. The facility is proposing a cyclone, wet scrubbers and a filter after the gasifiers and prior to the IC engines. These controls are expected to remove most of the particulates and condensable from the fuel and thus engine exhaust PM₁₀ emissions are expected to be below the permitted levels. However, in the absence of any source test data available for a similar system, initial source testing will be required to ensure that the engines are able to demonstrate compliance with the proposed PM₁₀ emission factor.

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

- Source testing to measure NO_x, CO, VOC, PM₁₀, and ammonia (NH₃) emissions from this unit when fired on syngas shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201, and 4702]
- Source testing to measure NO_x, CO, VOC, and ammonia (NH₃) emissions from this unit when fired on syngas shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

- {modified 3792} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NO_x, CO, VOC, and NH₃ concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
- The following methods shall be used for source testing when fired on syngas: NO_x (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM₁₀ (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH₃ - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- The Higher Heating Value (HHV) of the syngas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]
- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]
- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_x, CO, and O₂ analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

In addition, the facility is proposing a syngas conditioning system prior to being used as fuel in the IC engines or combusted in the backup flare. The conditioning system consists of a cyclone, wet scrubbing system, and a cartridge type filter. These controls are expected to remove most of the particulates and condensables. Therefore, fuel sulfur content of the treated syngas is expected to be very low. However, in the absence of any test data, initial and annual syngas fuel sulfur content analysis will be required.

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

- Fuel sulfur content analysis shall be performed within 60 days of the end of the commissioning period and at least annually thereafter, using ASTM D 1072, D 3031, D 4084, D 3246 or double GC for H₂S and mercaptans, or Dräger tubes for H₂S, or an equivalent method approved by the District. Records of the fuel sulfur analysis shall

be maintained and provided to the District upon request. [District Rules 2201 and 4702]

C-8980-3-0 (Backup Flare):

Pursuant to District Policy APR 1705, source testing is not required for this unit to demonstrate compliance with Rule 2201.

2. Monitoring

C-8980-1-0 and -2-0 (Syngas-Fired IC Engines):

The proposed syngas-fired engines are subject to the monitoring requirements of District Rule 4702 – Internal Combustion Engines. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District Rule 4702 requires monitoring of NO_x emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. However, Section 6.5.3 of District Rule 4702 requires monthly monitoring for engines equipped with non-certified control devices in order to demonstrate compliance with the emission limits in District Rule 4702. Therefore, monthly monitoring of NO_x, CO, and O₂ concentrations will be required. Since the engines will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

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

- The permittee shall monitor and record the stack concentration of NO_x, CO, and O₂ at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. After twelve consecutive months in which no deviations are observed, permittee may conduct monitoring once every calendar quarter rather than once every month. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH₃ at least once every calendar quarter in which a source test is not performed. NH₃ monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]

- If the NO_x, CO, or NH₃ concentrations corrected to 15% O₂, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

C-8980-3-0 (Backup Flare):

No monitoring is required for this permit unit to demonstrate compliance with Rule 2201.

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 ATCs to ensure compliance:

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
- The permittee shall maintain records of: (1) the date and time of NO_x, CO, O₂, and NH₃ measurements, (2) the O₂ concentration in percent and the measured NO_x, CO, and NH₃ concentrations corrected to 15% O₂, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH₃ emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

- The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]
- The permittee shall keep records, on a monthly basis, to demonstrate that daily and annual limits of biomass feedstock used to generate syngas stated in this permit are not exceeded. The permittee may use biomass delivery and inventory records for this purpose. [District Rule 2201]
- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

C-8980-3-0 (Backup Flare):

- Operator shall record the fuel meter reading each day the flare operates. Operator shall maintain annual fuel use records, and shall update the running annual total each month in which the flare operates. [District Rules 2201 and 4311]
- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4311]

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 Appendix F of this document for the AAQA summary sheet.

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

The proposed location is in a non-attainment area for the state's PM₁₀ as well as federal and state PM_{2.5} thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM₁₀ and PM_{2.5}.

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. 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 4001 New Source Performance Standards (NSPS)

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of NO_x, SO_x, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean-burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean-burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

Each of the two proposed engines with this project is a 1,631 bhp SI IC engines that will be constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engines are subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the permits. However, the permittee will be responsible for compliance with the applicable requirements of this regulation.

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

This rule incorporates NESHAPs from Part 63, Chapter 1, Title 40, Code of Federal Regulations (CFR) and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 63.

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part.

As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the permit. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

Rule 4101 Visible Emissions

Rule 4101 states that no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). Visible emissions are not expected to exceed Ringelmann 1 or 20% opacity; therefore, the following condition will be listed on ATCs to ensure compliance:

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

Rule 4102 Nuisance

Rule 4102 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 ATCs 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 one. According to the Technical Services Memo for this project (Appendix F), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

RMR Summary						
Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required?	Special Permit Requirements?
Unit 1-0 (Syngas Engine)	2.41	0.11*	0.00	3.07E-07	No	Yes
Unit 2-0 (Syngas Engine)	2.41	0.11*	0.00	3.07E-07	No	Yes
Unit 3-0 (Flare)	0.01	0.00	0.00	6.80E-10	No	No
Project Totals	4.83	0.22	0.01	6.15E-07		
Facility Totals	>1	0.22	0.01	6.15E-07		

* Natural gas or propane cannot be utilized simultaneously with Syngas, therefore Acute risk was determined by taking the worst case risk of either fuel sources.

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined in the table above based on the HRA Summary in Appendix F of this report, the emissions increases for this project were determined to be less than significant.

The following conditions will be listed on the ATCs to ensure the validity of the health risk assessment:

C-8980-1-0 and -2-0 (Syngas-Fired IC Engines):

- The syngas fuel for this engine shall be generated in the gasifier from the following list of biomass feed stocks: (1) Agricultural crop residues; (2) Bark, lawn, yard, and garden clippings; (3) Leaves, silvicultural residue, and tree and brush pruning; (4) Wood, wood chips, and wood waste. Wood waste is defined as solid waste consisting of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. Biomass feed stocks used in the gasifier shall not have been treated with or contaminated by chemicals containing or contributing to the formation of hazardous air pollutants. [District Rules 2201 and 4102; California Public Resources Code 40106(a) and Title 14 California Code of Regulations Section 18720(84)]
- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The total duration of the commissioning period for this engine shall not exceed 500 hours of operation of the engine. [District Rules 2201 and 4102]
- Ammonia (NH₃) emissions from this engine shall not exceed 10 ppmvd @ 15% O₂. [District Rule 2201 and 4102]
- When fired on PUC-quality natural gas or propane, Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be in operation. [District Rules 2201 and 4102]
- Engines under permit units C-8980-1 and -2 shall not be fired at the same time on PUC-quality natural gas or propane for maintenance and testing purposes. [District Rule 4102]
- Engines under permit units C-8980-1 and -2 shall not be in the commissioning period at the same time. [District Rule 4102]
- The permittee shall monitor and record the stack concentration of NH₃ at least once every calendar quarter in which a source test is not performed. NH₃ monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]
- The sulfur content of the syngas used as fuel in this engine shall not exceed 5 ppmv as H₂S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

All ATCs with this project:

- {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]

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot. The following calculations demonstrate compliance with this rule:

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

F-Factor for syngas: 12,100 dscf/MMBtu
PM₁₀ emission factor: 0.03 g-PM₁₀/bhp-hr
Percentage of PM as PM₁₀ in exhaust: 100%

$$0.03 \frac{\text{g-PM}}{\text{bph} - \text{hr}} \times \frac{393.236 \text{ bhp-hr}}{\text{MMBtu}} \times \frac{\text{MMBtu}}{12,100 \text{ dscf}} \times \frac{0.30 \text{ Btu}_{\text{out}}}{\text{Btu}_{\text{in}}} \times \frac{15.43 \text{ grain}}{\text{g-PM}} = 0.005 \frac{\text{grain}}{\text{dscf}}$$

Since this is less than 0.1 grain/dscf, compliance with this rule is expected. The following condition will be listed on the ATCs to ensure compliance:

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

C-8980-3-0 (Backup Flare):

Assumptions:

F-Factor for syngas: 12,100 dscf/MMBtu
PM₁₀ emission factor: 0.008 lb-PM₁₀/MMBtu
Percentage of PM as PM₁₀ in exhaust: 100%
Exhaust oxygen (O₂) concentration: 3%
Excess air correction to F-Factor = $\frac{20.9}{(20.9 - 3)} = 1.17$

Grain Loading Calculations:

$$\text{Grain Loading (GL)} = 0.008 \frac{\text{lb-PM}}{\text{MMBtu}} \times \frac{7,000 \text{ grain}}{\text{lb-PM}} \times \frac{\text{MMBtu}}{12,100 \text{ dscf}} \div 1.17 = 0.004 \frac{\text{grain}}{\text{dscf}}$$

Since this is less than 0.1 grain/dscf, compliance with this rule is expected. The following condition will be listed on the ATC to ensure compliance:

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

Rule 4202 Particulate Matter Emission Rate

Per section 4.1, particulate matter (PM) emissions from any source operation shall not exceed the allowable hourly emission rate (E) as calculated using the following applicable formulas:

$$E = 3.59 P^{0.62} \text{ (when, } P = \text{ process weight rate } \leq 30 \text{ tons/hr)}$$

$$E = 17.31 P^{0.16} \text{ (when, } P = \text{ process weight rate } > 30 \text{ tons/hr)}$$

Since the average wood consumption of each gasifier is 90 BDT/day or 3.75 BDT/hr, the allowable PM emission rate is:

$$\begin{aligned} E_{\max} &= 3.59 \times (P)^{0.62} \\ &= 3.59 \times (3.75)^{0.62} \\ &= 8.15 \text{ lb-PM/hr} \end{aligned}$$

C-8980-1-0 and -2-0 (Syngas-Fired IC Engines):

Based on the worst case daily PE2 calculated in Section VII.C.2 of this document and that 100% PM₁₀ is PM, the actual emission rate is:

$$\begin{aligned} E_{\text{actual}} &= 86.3 \text{ lb-PM}_{10}/\text{day} \div 24 \text{ hr/day} \times 1 \text{ lb-PM}/1 \text{ lb-PM}_{10} \\ &= 3.6 \text{ lb-PM/hr} \end{aligned}$$

Since the actual PM emissions rate (E_{actual}) is less than the maximum allowable PM emission rate ($E_{\max}$) for each permit unit, compliance with this rule is expected.

C-8980-3-0 (Backup Flare):

Based on the daily PE2 calculated in Section VII.C.2 of this document and that 100% PM₁₀ is PM, the actual emission rate is:

$$\begin{aligned} E_{\text{actual}} &= 2.8 \text{ lb-PM}_{10}/\text{day} \div 24 \text{ hr/day} \times 1 \text{ lb-PM}/1 \text{ lb-PM}_{10} \\ &= 0.12 \text{ lb-PM/hr} \end{aligned}$$

Since the actual PM emissions rate (E_{actual}) is less than the maximum allowable PM emission rate ($E_{\max}$) for each permit unit, compliance with this rule is expected.

Rule 4203 Particulate Matter Emissions from Incineration of Combustible Refuse

This rule limits the emission of particulate matter from disposing of combustible refuse. The provisions of this rule apply to any person, operation, facility, incinerator or equipment used to dispose of or process combustible refuse.

Pursuant to Section 3.11 of District Rule 1020, *Definitions*, combustible refuse is defined as any solid or liquid combustible waste material containing carbon in a free or combined state. Thus, wood chips from forest waste used as feedstock in this process meet the definition of combustible refuse.

However, the wood chips gasification will utilize pyrolysis process which is a thermo-chemical process conducted in a controlled temperature and low oxygen environment. The goal of this process is to ensure that the wood chips are not incinerated, thus pyrolysis is essentially a different process than incineration. Therefore, the wood gasification process proposed in this project is not an incineration of combustible refuse and this rule does not apply.

In addition, the syngas generated from this process is in gaseous form and will be utilized by the engines and the flare in gaseous form, it does not meet the definition of combustible refuse. Therefore, this rule does not apply.

Rule 4301 Fuel Burning Equipment

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

The two syngas fired IC engines are used to produce electrical power by internal combustion and mechanical power by directly coupling to the electrical generators; therefore, the engines do not meet the above definition of 'fuel burning equipment'. Similarly, the primary purpose of the backup flare is to dispose of excess syngas during gasifiers' startup, shutdown, and engines' breakdown periods, thus not meeting the above definition as well. Therefore, this rule is not applicable to this project.

Rule 4302 Incinerator Burning

This rule prohibits any incineration activity unless it is conducted in an approved multiple-chamber incinerator, or in equipment found by the APCO to be equally effective in controlling air pollution.

As discussed under Rule 4203 discussion above, the pyrolysis process utilized for the wood gasification is not an incineration process; therefore, Rule 4302 does not apply as well.

Rule 4311 Flares

C-8980-3-0 (Backup Flare):

This rule limits the emissions of volatile organic compounds (VOC), oxides of nitrogen (NO_x), and sulfur oxides (SO_x) from the operation of flares and is applicable to operations involving the use of flares.

Section 4.3 states that except for the recordkeeping requirements in Section 6.1.4 the requirements of this rule shall not apply to any stationary source that has the potential to emit, for all processes, less than ten (10.0) tons per year of VOC and less than ten (10.0) tons per year of NO_x.

As shown in Section VII.C.4 of this document, SSPE2 for each of NO_x and VOC emissions is less than 20,000 pounds per year (10.0 tons per year); therefore, the facility qualifies for the exemption of Section 4.3 and is only subject to the recordkeeping requirements of Section 6.1.4.

Section 6.1.4 requires that any facility claiming exemption under Section 4.3 must maintain records of annual throughput, material usage, or other information necessary to demonstrate compliance with that section. Therefore, the following conditions will be listed on the flare ATC to ensure exemption of Section 4.3:

- This flare shall be equipped with a non-resettable totalizing volumetric fuel meter. [District Rules 2201 and 4311]
- The total amount of syngas combusted in the flare shall not exceed 105.9 million standard cubic feet (MMscf) per year (equivalent to 1,000 hours of flare operation at full load). [District Rules 2201 and 4311]
- Operator shall record the fuel meter reading each day the flare operates. Operator shall maintain annual fuel use records, and shall update the running annual total each month in which the flare operates. [District Rules 2201 and 4311]
- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4311]

Rule 4702 Internal Combustion Engines

C-8980-1-0 and '-2-0 (Syngas-Fired IC Engines):

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides (SO_x) from internal combustion engines and applies to any internal combustion engine rated at 25 brake horsepower (bhp) or greater.

The proposed IC engines do not qualify for any exemptions listed in Section 4.0 of the rule.

5.0 Requirements:

Section 5.1 applies to stationary engines rated at least 25 bhp, up to, and including 50 bhp and used in non-agricultural operations. Since the proposed engines are greater than 50 bhp, this section does not apply.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0.

Since all compliance dates of Section 7.5 have passed, the proposed new engines are required to comply with the emission limits stated in Table 2; therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the proposed engines.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall comply with all the applicable requirements of the rule and one of the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

- 5.2.2.1.1 NO_x, CO, and VOC emission limits pursuant to Table 2;
- 5.2.2.1.2 SO_x control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and
- 5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the NO_x emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. As shown below, the applicant is proposing to comply with the NO_x emission limit requirement of Table 2 as required by Section 5.2.2.1.1; therefore, Section 5.2.2.2 is not applicable.

Section 5.2.2.3 allows that in lieu of complying with the NO_x, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. As shown below, the applicant is proposing to comply with the NO_x, CO, and VOC emission limit requirements of Table 2; therefore, Section 5.2.2.3 is not applicable.

Thus pursuant to Section 5.2.2.1, the proposed engines are required to comply with NO_x, CO, and VOC limits of Table 2 as follows:

Table 2 Emission Limits for a Spark-Ignited Internal Combustion Engine Rated at > 50 bhp Used Exclusively in Non-AO (All ppmv limits are corrected to 15% oxygen on a dry basis). Emission Limits are effective according to the compliance schedule specified in Section 7.5.			
Engine Type	NOx Limit (ppmv)	CO Limit (ppmv)	VOC Limit (ppmv)
1. Rich-Burn			
a. Waste Gas Fueled	50	2000	250
b. Cyclic Loaded, Field Gas Fueled	50	2000	250
c. Limited Use	25	2000	250
d. Rich-Burn Engine, not listed above	11	2000	250
2. Lean-Burn Engines			
a. Two-Stroke, Gaseous Fueled, > 50 bhp and < 100 bhp	75	2000	750
b. Limited Use	65	2000	750
c. Lean-Burn Engine used for gas compression	65 ppmv or 93% reduction	2000	750
d. Waste Gas Fueled	65 ppmv or 90% reduction	2000	750
e. Lean-Burn Engine, not listed above	11	2000	750

The proposed lean-burn engines are fired on syngas and do not satisfy the definition of waste gas; therefore, the engines are required to comply with the following emissions limits from Table 2, Row 2.e: 11 ppmvd NOx, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O₂).

The applicant is proposing lean-burn IC engines with emissions of 9 ppmvd NOx, 100 ppmvd CO, and 25 ppmvd VOC (all measured @ 15% O₂); which meet emission limits of Rule 4702. Therefore, the following condition will be listed on ATCs to ensure compliance with these emission limits:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 9 ppmvd NOx @ 15% O₂ (NOx referenced as NO₂) (equivalent to 0.18 g/bhp-hr); 0.03 g-PM₁₀/bhp-hr; 100 ppmvd CO @ 15% O₂ (equivalent to 1.22 g/bhp-hr); or 25 ppmvd VOC @ 15% O₂ (VOC referenced as CH₄) (equivalent to 0.17 g/bhp-hr). [District Rules 2201 and 4702]

Section 5.2.3 applies to spark-ignited engines used exclusively in agricultural operations. The proposed engines will be operated at a non-agricultural stationary source; therefore, this section does not apply.

Section 5.2.4 applies to certified compression-ignited engines. The proposed engines are not a compression-ignited engine; therefore, this section does not apply.

Section 5.2.5 applies to non-certified compression-ignited engines. The proposed engines are not compression-ignited; therefore, this section does not apply.

Section 5.3 specifies the sampling period for engines equipped with continuous emissions monitoring systems (CEMS). The proposed engines are not equipped with CEMS; therefore, this section does not apply.

Sections 5.4 and 5.5 apply to engines that use the percent emission reductions to comply with the NOx emission limitations. The proposed engines comply with the NOx emission limit of this rule, so these sections do not apply.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The proposed engines will comply with the applicable emission limits of Table 2 of this rule; therefore, payment of annual emissions fees is not required and this section does not apply.

5.7 Sulfur Oxides (SOx) Emission Control Requirements:

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply with one of the Sections 5.7.1 thru 5.7.6 below:

- 5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or
- 5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or
- 5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or
- 5.7.4 Use California Reformulated Diesel for compression-ignited engines; or
- 5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or
- 5.7.6 Install and properly operate an emission control system that reduces SO₂ emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

The facility will comply with Section 5.7.2 by limiting gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet. The average sulfur content of the syngas fuel for the engines will be limited to 5 ppmv or 0.02 g/bhp-hr (approximately equal to 0.1 grains sulfur per 100 standard cubic feet³). Therefore, the following condition will be listed on the ATCs to ensure compliance:

- The sulfur content of the syngas used as fuel in this engine shall not exceed 5 ppmv as H₂S. The applicant may utilize an averaging period of up to 24 hours in length for

$$3 \frac{5 \text{ parts-H}_2\text{S}}{10^6 \text{ parts}} \times \frac{32.06 \text{ lb-S}}{\text{lb-mole H}_2\text{S}} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3} \times \frac{64.06 \text{ lb-SO}_x}{32.06 \text{ lb-S}} \times \frac{\text{ft}^3}{137 \text{ Btu}} \times \frac{10^6 \text{ Btu}}{\text{MMBtu}} = 0.0062 \frac{\text{lb-SO}_x}{\text{MMBtu}}$$

$$0.0062 \frac{\text{lb-SO}_x}{\text{MMBtu}} \times \frac{\text{MMBtu}}{12,100 \text{ dscf}} \times \frac{0.30 \text{ Btu}_{\text{out}}}{1 \text{ Btu}_{\text{in}}} \times \frac{7,000 \text{ grain}}{\text{dscf}} = 0.001 \frac{\text{grain}}{\text{dscf}} = 0.1 \frac{\text{grain}}{100 \text{ dscf}}$$

demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

5.8 Monitoring Requirements:

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Sections 5.8.1 thru 5.8.11:

Section 5.8.1 specifies that for each engine with a rated brake horsepower of 1,000 bhp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for NO_x, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

- 5.8.1.1 Periodic NO_x and CO emission concentrations,
- 5.8.1.2 Engine exhaust oxygen concentration,
- 5.8.1.3 Air-to-fuel ratio,
- 5.8.1.4 Flow rate of reducing agents added to engine exhaust,
- 5.8.1.5 Catalyst inlet and exhaust temperature,
- 5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
- 5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of this rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic monitoring of catalyst inlet and outlet temperatures, ammonia injection rate, and NO_x, CO, and O₂ concentrations as specified in District Policy SSP-1810, dated 4/29/04 (revised 2/15/17). However, due to the experimental nature of the engine and fuel combination, the District will require NO_x and CO monitoring on a monthly basis for the first twelve months, instead of quarterly monitoring. Therefore, the following conditions will be listed on ATCs to ensure compliance:

- During initial performance testing, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system 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. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature and back pressure demonstrated during the initial compliance test that result in compliance with the CO and VOC emission limits shall be imposed as a condition in the final Permit to Operate. [District Rule 4702]
- The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]

- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O₂ at least once every month. Monthly monitoring of the stack concentration of CO and O₂ shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
- The permittee shall monitor and record the stack concentration of NO_x, CO, and O₂ at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. After twelve consecutive months in which no deviations are observed, permittee may conduct monitoring once every calendar quarter rather than once every month. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- If the NO_x, CO, or NH₃ concentrations corrected to 15% O₂, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- The permittee shall maintain records of: (1) the date and time of NO_x, CO, O₂, and NH₃ measurements, (2) the O₂ concentration in percent and the measured NO_x, CO, and NH₃ concentrations corrected to 15% O₂, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH₃ emission

concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The proposed engines will be subject to Section 5.8.1; therefore, this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The proposed engines include a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic monitoring of catalyst inlet and outlet temperatures, ammonia injection rate, and NO_x, CO, and O₂ concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B (Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The proposed engines will not have CEMS installed; therefore, this section is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the proposed engines include an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for the engines in this project. Therefore, the following condition will be listed on the ATCs to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the operator shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.8 requires that for each engine, the operator shall collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, the operator shall use a portable NOx analyzer to take NOx emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed and the engine is operated. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NOx emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All NOx emissions readings shall be reported to the APCO in a manner approved by the APCO. NOx emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. Therefore, the following conditions will be listed on the ATCs to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O₂ at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. After twelve consecutive months in which no deviations are observed, permittee may conduct monitoring once every calendar quarter rather than once every month. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The ATCs for the proposed engines will include requirements of a pre-approved alternate emissions monitoring plan that will require periodic monitoring of catalyst inlet and outlet temperatures, ammonia injection rate, and NOx, CO, and O₂ emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECPP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the proposed engines; therefore this section is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The proposed engines are subject to the requirements of Section 5.8; therefore, this section is not applicable.

5.10 SOx Emissions Monitoring Requirements:

Section 5.10 specifies SOx Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

- 5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,
- 5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and
- 5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

As discussed under Section 5.7 of this rule above, the facility will comply with Section 5.7.2 by limiting gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet. Therefore, the following condition will be listed on the ATCs to ensure compliance with annual sulfur fuel analysis of Section 5.10.1:

- Fuel sulfur content analysis shall be performed within 60 days of the end of the commissioning period and at least annually thereafter, using ASTM D 1072, D 3031, D 4084, D 3246 or double GC for H₂S and mercaptans, or Drager tubes for H₂S, or an equivalent method approved by the District. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

5.11 Permit-Exempt Equipment Registration Requirements:

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The proposed engines are required to have a District Permit to Operate; therefore, this section is not applicable.

6.0 Administrative Requirements:

6.1 Emission Control Plan:

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously-approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

- 6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
- 6.1.1.2 Engines subject to Section 8.0;
- 6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
- 6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for the engine:

- 6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
- 6.1.2.2 Engine manufacturer,
- 6.1.2.3 Model designation and engine serial number,
- 6.1.2.4 Rated brake horsepower,
- 6.1.2.5 Type of fuel and type of ignition,
- 6.1.2.6 Combustion type: rich-burn or lean-burn,
- 6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
- 6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
- 6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
- 6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,
- 6.1.2.11 Applicable emission limits,
- 6.1.2.12 Documentation showing existing emissions of NO_x, VOC, and CO, and
- 6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engines are in compliance with the emission requirements of this rule.

Section 6.1.4 requires that for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2.

The applicant has submitted all the required information for Section 6.1 in the application for the engines evaluated under this project; therefore, the requirements of Section 6.1 are satisfied.

6.2 Recordkeeping:

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating logs shall include, on a monthly basis, the following information:

- 6.2.1.1 Total hours of operation,
- 6.2.1.2 Type of fuel used,
- 6.2.1.3 Maintenance or modifications performed,
- 6.2.1.4 Monitoring data,
- 6.2.1.5 Compliance source test results, and
- 6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
- 6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

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

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request. Therefore, the following condition will be listed on the ATCs to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. The applicant is not claiming an exemption for the proposed engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

6.3 Compliance Testing:

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Section 6.3.2 through Section 6.3.4 shall apply to the following engines:

- 6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
- 6.3.1.2 Engines subject to Section 8.0;
- 6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
- 6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

- 6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.
- 6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.
- 6.3.2.3 A portable NO_x analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

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

- Source testing to measure NO_x, CO, VOC, PM₁₀, and ammonia (NH₃) emissions from this unit when fired on syngas shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201, and 4702]
- Source testing to measure NO_x, CO, VOC, and ammonia (NH₃) emissions from this unit when fired on syngas shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, NO_x, and CO concentrations shall be reported in ppmv, corrected to 15 percent

oxygen. For engines that comply with a percent reduction limit, the percent reduction of NO_x emissions shall also be reported.

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

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- {modified 3792} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NO_x, CO, VOC, and NH₃ concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters will be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The proposed engines will be fueled by syngas; therefore, this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for the engines; therefore, this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

- 6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
- 6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
- 6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
- 6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
- 6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
- 6.4.6 SO_x Test Methods
 - 6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.
 - 6.4.6.2 Determination of total sulfur as hydrogen sulfide (H₂S) content – EPA Method 11 or EPA Method 15, as appropriate.
 - 6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.
 - 6.4.6.4 The SO_x emission control system efficiency shall be determined using the following:

$$\% \text{ Control Efficiency} = [(C_{\text{SO}_2, \text{inlet}} - C_{\text{SO}_2, \text{outlet}}) / C_{\text{SO}_2, \text{inlet}}] \times 100$$

Where:

$C_{\text{SO}_2, \text{inlet}}$ = concentration of SO_x (expressed as SO₂) at the inlet side of the SO_x emission control system, in lb/Dscf

$C_{\text{SO}_2, \text{outlet}}$ = concentration of SO_x (expressed as SO₂) at the outlet side of the SO_x emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (HHV) of the fuel shall be determined by one of the following test methods:

6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.

6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

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

- The following methods shall be used for source testing when fired on syngas: NO_x (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM₁₀ (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH₃ - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed within 60 days of the end of the commissioning period and at least annually thereafter, using ASTM D 1072, D 3031, D 4084, D 3246 or double GC for H₂S and mercaptans, or Drager tubes for H₂S, or an equivalent method approved by the District. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
- The Higher Heating Value (HHV) of the syngas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:

- 6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

- 6.5.1.2 Engines subject to Section 8.0;
- 6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.
- 6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Each of the two proposed engines will be equipped with an SCR system for control of NO_x and an oxidation catalyst for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engines.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_x, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_x, CO, VOC, or oxygen concentrations.

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engines will be operated and maintained per the manufacturer's specifications.

Section 6.5.7 requires procedures and a schedule for using a portable NO_x analyzer to take NO_x emission readings pursuant to Section 5.8.9.

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO.

NO_x Emissions

In order to satisfy the I&M requirements for NO_x emissions, the applicant has proposed to perform the following:

1. The permittee will take periodic NO_x emission concentration measurements with a portable analyzer at least once every month. After twelve consecutive months in which no deviations are observed, the permittee may conduct monitoring once every calendar quarter rather than once every month.

2. To ensure that NO_x emissions concentrations are not being exceeded between periodic NO_x portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and NO_x emissions. The appropriate ranges for each operating load will be established during initial source testing and will be monitored at least once per month.

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

- During initial performance testing, the SCR system reagent 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. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NO_x emission limits shall be imposed as a condition in the final Permit to Operate. [District Rule 4702]
- If the SCR system reagent injection rate is outside of the established acceptable range, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NO_x and O₂ at least once every month. Monthly monitoring of the stack concentration of NO_x and O₂ shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
- The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]
- The permittee shall monitor and record the stack concentration of NO_x, CO, and O₂ at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. After twelve consecutive months in which no deviations are observed, permittee may conduct monitoring once every calendar quarter rather than once every month. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH₃ at least once every calendar quarter in which a source test is not performed. NH₃ monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days

of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]

- If the NO_x, CO, or NH₃ concentrations corrected to 15% O₂, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

CO and VOC Emissions

In order to satisfy the I&M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. The permittee will take periodic CO emission concentration measurements with a portable analyzer at least once every month. After twelve consecutive months in which no deviations are observed, the permittee may conduct monitoring once every calendar quarter rather than once every month. If the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, quarterly emission concentration measurements with a portable analyzer for VOC emissions will not be required.
2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emission concentration measurements, the applicant is proposing to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure. The appropriate ranges for each operating load will be established during initial source testing and will be monitored at least once per month.

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

- During initial performance testing, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system 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. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature and back pressure demonstrated during the initial compliance test that result in compliance with the CO and VOC emission limits shall be imposed as a condition in the final Permit to Operate. [District Rule 4702]

- The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]
- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O₂ at least once every month. Monthly monitoring of the stack concentration of CO and O₂ shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
- The permittee shall monitor and record the stack concentration of NO_x, CO, and O₂ at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. After twelve consecutive months in which no deviations are observed, permittee may conduct monitoring once every calendar quarter rather than once every month. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- If the NO_x, CO, or NH₃ concentrations corrected to 15% O₂, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time. The applicant has proposed to comply with the I&M plan modification requirements per this section of the rule. The following condition will be listed on the ATCs to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECPP) option of Section 8.0. The proposed engines will be required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECPP) to comply with the NO_x emission requirements of Section 5.2 for a group of engines. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the proposed engines; therefore, this section of the rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the proposed engines are not currently being proposed; therefore, this section of the rule is not applicable at this time.

Conclusion

As shown above, the proposed engines will satisfy the applicable requirements of District Rule 4702. Therefore, the engines will be in compliance as of the date of initial operation and the following conditions will be listed on the ATCs to ensure continued compliance:

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

Rule 4801 Sulfur Compounds

The purpose of this rule is to limit the emissions of sulfur compounds. Section 3.1 specifies that 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 sulfur dioxide (SO₂), on a dry basis averaged over 15 consecutive minutes.

C-8980-1-0 and -2-0 (Syngas-Fired IC Engines):

To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from each engine will be calculated using the maximum sulfur content allowed for the syngas fuel, which is 0.0064 lb-SO_x/MMBtu.

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

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

Where,

n = moles SO₂

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

P (Standard Pressure) = 14.7 psi

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

Molecular weight of SO_x (as SO₂) = 64.06 lb/lb-mol

$$\begin{aligned} & \frac{5 \text{ parts-H}_2\text{S}}{10^6 \text{ parts}} \times \frac{32.06 \text{ lb-S}}{\text{lb-mole H}_2\text{S}} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3} \times \frac{64.06 \text{ lb-SO}_x}{32.06 \text{ lb-S}} \times \frac{\text{ft}^3}{137 \text{ Btu}} \times \frac{10^6 \text{ Btu}}{\text{MMBtu}} = 0.0062 \frac{\text{lb-SO}_x}{\text{MMBtu}} \\ & 0.0062 \frac{\text{lb-SO}_x}{\text{MMBtu}} \times \frac{1 \text{ MMBtu}}{12,100 \text{ ft}^3_{\text{exhaust}}} \times \frac{1 \text{ lb-mol}}{64.06 \text{ lb-SO}_x} \times \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb-mol} \cdot ^\circ\text{R}} \times \frac{520 ^\circ\text{R}}{14.7 \text{ psi}} \times \frac{10^6 \text{ ft}^3}{\text{MM ft}^3} = 3.0 \text{ ppm} \end{aligned}$$

Since 3.0 ppmv is ≤ 2000 ppmv, the IC engines are expected to comply with Rule 4801; therefore, the following condition will be listed on the ATCs to ensure compliance:

- The sulfur content of the syngas used as fuel in this engine shall not exceed 5 ppmv as H₂S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

C-8980-3-0 (Backup Flare):

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

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

Where,

n = moles SO_2

T (standard temperature) = $60^\circ \text{F} = 520^\circ \text{R}$

P (Standard Pressure) = 14.7 psi

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

Molecular weight of SO_x (as SO_2) = 64.06 lb/lb-mol

$$0.0065 \frac{\text{lb-SO}_x}{\text{MMBtu}} \times \frac{1 \text{ MMBtu}}{12,100 \text{ ft}^3_{\text{exhaust}}} \times \frac{1 \text{ lb} - \text{mol}}{64.06 \text{ lb-SO}_x} \times \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb-mol} \cdot ^\circ \text{R}} \times \frac{520^\circ \text{R}}{14.7 \text{ psi}} \times \frac{10^6 \text{ ft}^3}{\text{MM ft}^3} = 3.2 \text{ ppm}$$

Since 3.2 ppmv is $\leq$ 2000 ppmv, the flare is expected to comply with Rule 4801; therefore, the following condition will be listed on the ATC to ensure compliance:

- Emissions from this flare shall not exceed any of the following limits: 0.068 lb- NO_x /MMBtu, 0.0065 lb- SO_x /MMBtu, 0.008 lb- PM_{10} /MMBtu, 0.31 lb-CO/MMBtu, or 0.063 lb-VOC/MMBtu. [District Rules 2201 and 4801]

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)

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 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; and
- 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.

Greenhouse Gas (GHG) Significance Determination

District is a Responsible Agency

It is determined that another agency has prepared an environmental review document for the project. 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). As a Responsible Agency, the District is limited to mitigating or avoiding impacts for which it has statutory authority. The District does not have statutory authority for regulating greenhouse gas emissions. The District has determined that the applicant is responsible for implementing greenhouse gas mitigation measures, if any, imposed by the Lead Agency.

District CEQA Findings

The County of Madera (County) is the public agency having principal responsibility for approving the project. As such, the County served as the Lead Agency (CCR §15367). In approving the project, the Lead Agency prepared and adopted a Mitigated Negative Declaration. The Lead Agency filed a Notice of Determination, stating that the environmental document was adopted pursuant to the provisions of CEQA and concluding that the project would not have a significant effect on the environment.

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), (CCR §15381). As a Responsible Agency the District complies with CEQA by considering the environmental document prepared by the Lead Agency, and by reaching its own conclusion on whether and how to approve the project (CCR §15096).

The District has considered the Lead Agency's environmental document. Furthermore, the District has conducted an engineering evaluation of the project, this document, which demonstrates that Stationary Source emissions from the project would be below the District's thresholds of significance for criteria pollutants. Thus, the District finds that through a combination of project design elements, compliance with applicable District rules and regulations, and compliance with District air permit conditions, project specific stationary source emissions will have a less than significant impact on air quality. 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)).

Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs C-8980-1-0 thru '-3-0 subject to the permit conditions on the attached draft ATCs in Appendix A.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-8980-1-0	3020-08A-C	1,000 kW electrical generation	\$1,759
C-8980-2-0	3020-08A-C	1,000 kW electrical generation	\$1,759
C-8980-3-0	3020-02-G	14.5 MMBtu/hr flare	\$936

Appendixes

- A: Draft ATCs
- B: AP-42 Emission Factors
- C: Quarterly Net Emissions Change (QNEC)
- D: BACT Analysis for Syngas-Fired IC Engines (C-8980-1-0 and '-2-0)
- E: BACT Analysis for Syngas-Fired Flare (C-8980-3-0)
- F: HRA and AAQA Summary
- G: Uncontrolled Emission Calculations for Permit Exempt Equipment
- H: Syngas F-Factor Calculations

APPENDIX A

Draft ATCs

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT

PERMIT NO: C-8980-1-0

LEGAL OWNER OR OPERATOR: NORTH FORK COMMUNITY POWER
MAILING ADDRESS: PO BOX 30032
WALNUT CREEK, CA 94598

LOCATION: 57839 ROAD 225
NORTH FORK, CA 93643

EQUIPMENT DESCRIPTION:

1.0 MW ELECTRICAL POWER GENERATION OPERATION (#1) UTILIZING BIOMASS GASIFICATION (PYROLYSIS) PROCESS CONSISTING OF THE FOLLOWING: A GE MODEL 1200 KG WOOD CHIPS GASIFIER; SYNTHETIC GAS (SYNGAS) CONDITIONING SYSTEM INCLUDING A CYCLONE, WET SCRUBBERS, A FILTER, AND CONDENSATE TRAPS; A 1,631 BHP GE JENBACHER MODEL JMS 612 F62 SYNGAS-FIRED LEAN-BURN IC ENGINE (#1) WITH A STEULER MODEL DENOX-J612F62/1 SELECTIVE CATALYTIC REDUCTION (SCR) AND AN OXIDATION CATALYST POWERING AN ELECTRICAL GENERATOR; AND ONE PERMIT EXEMPT COOLING TOWER (LESS THAN 10,000 GALLONS PER MINUTE) (REVISED 11/16/18)

CONDITIONS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [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. {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]
6. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
7. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU **MUST** NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 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.

Samir Sheikh, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services

C-8980-1-0 : Nov 16 2018 10:04AM - AHMADS : Joint Inspection Required with AHMADS

8. This engine shall be fired on synthetic gas (syngas) fuel only, except for up to 200 hours per year for maintenance and testing purposes and up to 200 hours during commissioning period during which the engine could be fired on PUC-quality natural gas or propane. [District Rule 2201]
9. This engine shall only use syngas as fuel that has been treated in the syngas conditioning system. [District Rule 2201]
10. When fired on PUC-quality natural gas or propane, Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be in operation. [District Rules 2201 and 4102]
11. Engines under permit units C-8980-1 and -2 shall not be fired at the same time on PUC-quality natural gas or propane for maintenance and testing purposes. [District Rule 4102]
12. Engines under permit units C-8980-1 and -2 shall not be in the commissioning period at the same time. [District Rule 4102]
13. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
14. The syngas fuel for this engine shall be generated in the gasifier from the following list of biomass feed stocks: (1) Agricultural crop residues; (2) Bark, lawn, yard, and garden clippings; (3) Leaves, silvicultural residue, and tree and brush pruning; (4) Wood, wood chips, and wood waste. Wood waste is defined as solid waste consisting of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. Biomass feed stocks used in the gasifier shall not have been treated with or contaminated by chemicals containing or contributing to the formation of hazardous air pollutants. [District Rules 2201 and 4102; California Public Resources Code 40106(a) and Title 14 California Code of Regulations Section 18720(84)]
15. The combined total amount of all biomass feedstock used to generate syngas in the two gasifiers under permit units C-8980-1 and -2 shall not exceed the following limits: 90 Bone Dry Ton (BDT) per day and 20,000 BDT per calendar year. [District Rule 2201]
16. The sulfur content of the syngas used as fuel in this engine shall not exceed 5 ppmv as H₂S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
17. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]
18. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
19. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
20. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The total duration of the commissioning period for this engine shall not exceed 500 hours of operation of the engine. [District Rules 2201 and 4102]
21. Commissioning period ends when either of the following two events occurs first: 1) 500 hours of operation of the engine as allowed during the commissioning period, or 2) the electrical generator associated with this engine has successfully demonstrated to generate a minimum of 800 kw of electric power for 72 continuous hours and the Selective Catalytic Reduction (SCR) system and the oxidation catalyst have completed the breaking-in period, as recommended by the manufacturer. The permittee shall submit any relevant data to the District to demonstrate the end of the commissioning period no later than 14 days after such demonstration is completed. [District Rule 2201]

DRAFT

CONDITIONS CONTINUE ON NEXT PAGE

22. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 500 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 or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 500 firing hours without abatement shall expire. [District Rule 2201]
23. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
24. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the SCR system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
25. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
26. Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.03 g-PM10/bhp-hr, 14.5 g-CO/bhp-hr, 0.43 g-VOC/bhp-hr. [District Rule 2201]
27. After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 9 ppmvd NOx @ 15% O2 (NOx referenced as NO2) (equivalent to 0.18 g/bhp-hr); 0.03 g-PM10/bhp-hr; 100 ppmvd CO @ 15% O2 (equivalent to 1.22 g/bhp-hr); or 25 ppmvd VOC @ 15% O2 (VOC referenced as CH4) (equivalent to 0.17 g/bhp-hr). [District Rules 2201 and 4702]
28. When fired on PUC-quality natural gas or propane, emissions from this unit shall not exceed any of the following limits: 0.18 g-NOx/bhp-hr, 0.012 g-SOx/bhp-hr, 0.175 g-PM10/bhp-hr, 1.22 g-CO/bhp-hr, or 0.17 g-VOC/bhp-hr. [District Rule 2201]
29. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
30. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]
31. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]
32. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit when fired on syngas shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201, and 4702]
33. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit when fired on syngas shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]
34. Fuel sulfur content analysis shall be performed within 60 days of the end of the commissioning period and at least annually thereafter, using ASTM D 1072, D 3031, D 4084, D 3246 or double GC for H2S and mercaptans, or Draeger tubes for H2S, or an equivalent method approved by the District. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
35. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
36. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

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37. The following methods shall be used for source testing when fired on syngas: NO_x (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM₁₀ (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH₃ - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
38. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]
39. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
40. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]
41. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_x, CO, and O₂ analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]
42. The permittee shall monitor and record the stack concentration of NO_x, CO, and O₂ at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. After twelve consecutive months in which no deviations are observed, permittee may conduct monitoring once every calendar quarter rather than once every month. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
43. The permittee shall monitor and record the stack concentration of NH₃ at least once every calendar quarter in which a source test is not performed. NH₃ monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]
44. If the NO_x, CO, or NH₃ concentrations corrected to 15% O₂, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
45. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

46. The permittee shall maintain records of: (1) the date and time of NO_x, CO, O₂, and NH₃ measurements, (2) the O₂ concentration in percent and the measured NO_x, CO, and NH₃ concentrations corrected to 15% O₂, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH₃ emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]
47. The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]
48. During initial performance testing, the SCR system reagent 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. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NO_x emission limits shall be imposed as a condition in the final Permit to Operate. [District Rule 4702]
49. If the SCR system reagent injection rate is outside of the established acceptable range, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NO_x and O₂ at least once every month. Monthly monitoring of the stack concentration of NO_x and O₂ shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
50. During initial performance testing, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system 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. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature and back pressure demonstrated during the initial compliance test that result in compliance with the CO and VOC emission limits shall be imposed as a condition in the final Permit to Operate. [District Rule 4702]
51. The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]
52. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O₂ at least once every month. Monthly monitoring of the stack concentration of CO and O₂ shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
53. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

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54. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]
55. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]
56. The permittee shall keep records, on a monthly basis, to demonstrate that daily and annual limits of biomass feedstock used to generate syngas stated in this permit are not exceeded. The permittee may use biomass delivery and inventory records for this purpose. [District Rule 2201]
57. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

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San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT

PERMIT NO: C-8980-2-0

LEGAL OWNER OR OPERATOR: NORTH FORK COMMUNITY POWER

MAILING ADDRESS: PO BOX 30032
WALNUT CREEK, CA 94598

LOCATION: 57839 ROAD 225
NORTH FORK, CA 93643

EQUIPMENT DESCRIPTION:

1.0 MW ELECTRICAL POWER GENERATION OPERATION (#2) UTILIZING BIOMASS GASIFICATION (PYROLYSIS) PROCESS CONSISTING OF THE FOLLOWING: A GE MODEL 1200 KG WOOD CHIPS GASIFIER; SYNTHETIC GAS (SYNGAS) CONDITIONING SYSTEM INCLUDING A CYCLONE, WET SCRUBBERS, A FILTER, AND CONDENSATE TRAPS; A 1,631 BHP GE JENBACHER MODEL JMS 612 F62 SYNGAS-FIRED LEAN-BURN IC ENGINE (#2) WITH A STEULER MODEL DENOX-J612F62/1 SELECTIVE CATALYTIC REDUCTION (SCR) AND AN OXIDATION CATALYST POWERING AN ELECTRICAL GENERATOR; AND ONE PERMIT EXEMPT COOLING TOWER (LESS THAN 10,000 GALLONS PER MINUTE) (REVISED 11/16/18)

CONDITIONS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [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. {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]
6. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
7. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 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.

Samir Sheikh, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services

C-8980-2-0 : Nov 16 2018 10:04AM -- AHMADS : Joint Inspection Required with AHMADS

8. This engine shall be fired on synthetic gas (syngas) fuel only, except for up to 200 hours per year for maintenance and testing purposes and up to 200 hours during commissioning period during which the engine could be fired on PUC-quality natural gas or propane. [District Rule 2201]
9. This engine shall only use syngas as fuel that has been treated in the syngas conditioning system. [District Rule 2201]
10. When fired on PUC-quality natural gas or propane, Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be in operation. [District Rules 2201 and 4102]
11. Engines under permit units C-8980-1 and -2 shall not be fired at the same time on PUC-quality natural gas or propane for maintenance and testing purposes. [District Rule 4102]
12. Engines under permit units C-8980-1 and -2 shall not be in the commissioning period at the same time. [District Rule 4102]
13. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
14. The syngas fuel for this engine shall be generated in the gasifier from the following list of biomass feed stocks: (1) Agricultural crop residues; (2) Bark, lawn, yard, and garden clippings; (3) Leaves, silvicultural residue, and tree and brush pruning; (4) Wood, wood chips, and wood waste. Wood waste is defined as solid waste consisting of wood pieces or particles which are generated from the manufacturing or production of wood products, harvesting, processing or storage of raw wood materials, or construction and demolition activities. Biomass feed stocks used in the gasifier shall not have been treated with or contaminated by chemicals containing or contributing to the formation of hazardous air pollutants. [District Rules 2201 and 4102; California Public Resources Code 40106(a) and Title 14 California Code of Regulations Section 18720(84)]
15. The combined total amount of all biomass feedstock used to generate syngas in the two gasifiers under permit units C-8980-1 and -2 shall not exceed the following limits: 90 Bone Dry Ton (BDT) per day and 20,000 BDT per calendar year. [District Rule 2201]
16. The sulfur content of the syngas used as fuel in this engine shall not exceed 5 ppmv as H₂S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
17. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]
18. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
19. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
20. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The total duration of the commissioning period for this engine shall not exceed 500 hours of operation of the engine. [District Rules 2201 and 4102]
21. Commissioning period ends when either of the following two events occurs first: 1) 500 hours of operation of the engine as allowed during the commissioning period, or 2) the electrical generator associated with this engine has successfully demonstrated to generate a minimum of 800 kw of electric power for 72 continuous hours and the Selective Catalytic Reduction (SCR) system and the oxidation catalyst have completed the breaking-in period, as recommended by the manufacturer. The permittee shall submit any relevant data to the District to demonstrate the end of the commissioning period no later than 14 days after such demonstration is completed. [District Rule 2201]

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22. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 500 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 or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 500 firing hours without abatement shall expire. [District Rule 2201]
23. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
24. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the SCR system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
25. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
26. Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.03 g-PM10/bhp-hr, 14.5 g-CO/bhp-hr, 0.43 g-VOC/bhp-hr. [District Rule 2201]
27. After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 9 ppmvd NOx @ 15% O2 (NOx referenced as NO2) (equivalent to 0.18 g/bhp-hr); 0.03 g-PM10/bhp-hr; 100 ppmvd CO @ 15% O2 (equivalent to 1.22 g/bhp-hr); or 25 ppmvd VOC @ 15% O2 (VOC referenced as CH4) (equivalent to 0.17 g/bhp-hr). [District Rules 2201 and 4702]
28. When fired on PUC-quality natural gas or propane, emissions from this unit shall not exceed any of the following limits: 0.18 g-NOx/bhp-hr, 0.012 g-SOx/bhp-hr, 0.175 g-PM10/bhp-hr, 1.22 g-CO/bhp-hr, or 0.17 g-VOC/bhp-hr. [District Rule 2201]
29. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
30. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]
31. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]
32. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit when fired on syngas shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201, and 4702]
33. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit when fired on syngas shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]
34. Fuel sulfur content analysis shall be performed within 60 days of the end of the commissioning period and at least annually thereafter, using ASTM D 1072, D 3031, D 4084, D 3246 or double GC for H2S and mercaptans, or Draeger tubes for H2S, or an equivalent method approved by the District. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
35. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
36. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

37. The following methods shall be used for source testing when fired on syngas: NO_x (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM₁₀ (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH₃ - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
38. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]
39. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
40. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]
41. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NO_x, CO, and O₂ analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]
42. The permittee shall monitor and record the stack concentration of NO_x, CO, and O₂ at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. After twelve consecutive months in which no deviations are observed, permittee may conduct monitoring once every calendar quarter rather than once every month. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
43. The permittee shall monitor and record the stack concentration of NH₃ at least once every calendar quarter in which a source test is not performed. NH₃ monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]
44. If the NO_x, CO, or NH₃ concentrations corrected to 15% O₂, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
45. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

46. The permittee shall maintain records of: (1) the date and time of NO_x, CO, O₂, and NH₃ measurements, (2) the O₂ concentration in percent and the measured NO_x, CO, and NH₃ concentrations corrected to 15% O₂, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH₃ emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]
47. The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]
48. During initial performance testing, the SCR system reagent 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. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NO_x emission limits shall be imposed as a condition in the final Permit to Operate. [District Rule 4702]
49. If the SCR system reagent injection rate is outside of the established acceptable range, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NO_x and O₂ at least once every month. Monthly monitoring of the stack concentration of NO_x and O₂ shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
50. During initial performance testing, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system 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. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature and back pressure demonstrated during the initial compliance test that result in compliance with the CO and VOC emission limits shall be imposed as a condition in the final Permit to Operate. [District Rule 4702]
51. The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]
52. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O₂ at least once every month. Monthly monitoring of the stack concentration of CO and O₂ shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
53. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

54. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]
55. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]
56. The permittee shall keep records, on a monthly basis, to demonstrate that daily and annual limits of biomass feedstock used to generate syngas stated in this permit are not exceeded. The permittee may use biomass delivery and inventory records for this purpose. [District Rule 2201]
57. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

DRAFT

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT

PERMIT NO: C-8980-3-0

LEGAL OWNER OR OPERATOR: NORTH FORK COMMUNITY POWER

MAILING ADDRESS: PO BOX 30032
WALNUT CREEK, CA 94598

LOCATION: 57839 ROAD 225
NORTH FORK, CA 93643

EQUIPMENT DESCRIPTION:

14.5 MMBTU/HR SYNGAS-FIRED BACKUP FLARE FOR DISPOSAL OF SYNGAS PRODUCED FROM PERMIT UNITS C 8980-1 AND '2 (REVISED 11/16/18)

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. 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 1/4 or 5% opacity. [District Rules 2201 and 4101]
3. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. This flare shall only incinerate syngas that has been treated in the wet scrubbing system. [District Rule 2201]
5. This flare shall be equipped with a non-resettable totalizing volumetric fuel meter. [District Rules 2201 and 4311]
6. The total amount of syngas combusted in the flare shall not exceed 105.9 million standard cubic feet (MMscf) per year (equivalent to 1,000 hours of flare operation at full load). [District Rules 2201 and 4311]
7. Emissions from this flare shall not exceed any of the following limits: 0.068 lb-NOx/MMBtu, 0.0065 lb-SOx/MMBtu, 0.008 lb-PM10/MMBtu, 0.31 lb-CO/MMBtu, or 0.063 lb-VOC/MMBtu. [District Rules 2201 and 4801]
8. Operator shall record the fuel meter reading each day the flare operates. Operator shall maintain annual fuel use records, and shall update the running annual total each month in which the flare operates. [District Rules 2201 and 4311]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 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.

Samir Sheikh, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services

C-8980-3-0 : Nov 16 2018 10:04AM - AHMADS : Joint Inspection Required with AHMADS

9. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4311]

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APPENDIX B

AP-42 Emission Factors

C-8980-1-0 & -2-0

Syngas-Fired IC Engines EF (PM₁₀)

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES^a
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO _x ^c 90 - 105% Load	4.08 E+00	B
NO _x ^c <90% Load	8.47 E-01	B
CO ^c 90 - 105% Load	3.17 E-01	C
CO ^c <90% Load	5.57 E-01	B
CO ₂ ^d	1.10 E+02	A
SO ₂ ^e	5.88 E-04	A
TOC ^f	1.47 E+00	A
Methane ^g	1.25 E+00	C
VOC ^h	1.18 E-01	C
PM ₁₀ (filterable) ⁱ	7.71 E-05	D
PM _{2.5} (filterable) ⁱ	7.71 E-05	D
PM Condensable ^j	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane ^k	<4.00 E-05	E
1,1,2-Trichloroethane ^k	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene ^k	2.67E-04	D
1,3-Dichloropropene ^k	<2.64 E-05	E
2-Methylnaphthalene ^k	3.32 E-05	C
2,2,4-Trimethylpentane ^k	2.50 E-04	C
Acenaphthene ^k	1.25 E-06	C

C-8980-5-0 : Flare EFs

Table 13.5-1 (English Units). THC, NO_x AND SOOT EMISSIONS FACTORS FOR FLARE OPERATIONS^a

EMISSIONS FACTOR RATING: B

Pollutant	SCC ^d	Emissions Factor Value	Emissions Factor Units
Total hydrocarbons ^b	30190099; 30119701; 30119705; 30119709; 30119741	0.14	lb/10 ⁶ Btu
Nitrogen oxides ^c		0.068	lb/10 ⁶ Btu
Soot ^c		0 - 274	μg/L

^a Reference 1. Based on tests using crude propylene containing 80% propylene and 20% propane.

^b Measured as methane equivalent. The THC emissions factor may not be appropriate for reporting VOC emissions when a VOC emissions factor exists.

^c Soot in concentration values: nonsmoking flares, 0 micrograms per liter (μg/L); lightly smoking flares, 40 μg/L; average smoking flares, 177 μg/L; and heavily smoking flares, 274 μg/L.

^d See Table 13.5-3 for a description of these SCCs.

C-8980-3-0; Flare Efs

Table 13.5-2 (English Units). VOC and CO EMISSIONS FACTORS FOR FLARE OPERATIONS^a

Pollutant	SCC ^d	Emissions Factor (lb/10 ⁶ Btu)	Representativeness
Volatile organic compounds ^b	30190099; 30600904; 30119701; 30119705; 30119709; 30119741; 30119799; 30130115;	0.66	Poorly
Carbon monoxide ^c	30600201; 30600401; 30600508; 30600903; 30600999; 30601701; 30601801; 30688801; 40600240	0.31	Poorly

^a These factors apply to well operated flares achieving at least 98% destruction efficiency and operating in compliance with the current General Provisions requirements of 40 CFR Part 60, i.e. >300 btu/scf net heating value in the vent gas and less than the specified maximum flare tip velocity. The VOC emissions factor data set had an average destruction efficiency of 98.9%, and the CO emissions factor data set had an average destruction efficiency of 99.1% (based on test reports where destruction efficiency was provided). These factors are based on steam-assisted and air-assisted flares burning a variety of vent gases.

^b References 4-9 and 11.

^c References 1, 4-8 and 11.

^d See Table 13.5-3 for a description of these SCCs.

APPENDIX C

Quarterly Net Emissions Change (QNEC)

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.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

C-8980-1-0 and '2-0 (Syngas-Fired IC Engines):

$Quarterly\ PE2\ (lb/qtr) = PE2\ (lb/yr) \div 4\ qtr/yr$

Pollutant	Annual PE2 (lb/yr)	Quarterly PE2 (lb/qtr)
NOx	7,144	1,786
SOx	625	156.25
PM ₁₀	1,049	262.25
CO	62,304	15,576
VOC	5,822	1,455.5

$Quarterly\ PE1\ (lb/qtr) = PE1\ (lb/yr) \div 4\ qtr/yr = 0$ since these are new emission units.

Thus: $QNEC\ (lb/qtr) = Quarterly\ PE2\ (lb/qtr) - Quarterly\ PE1\ (lb/qtr)$

Quarterly NEC [QNEC]			
Pollutant	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NOx	1,786	0	1,786
SOx	156.25	0	156.25
PM ₁₀	262.25	0	262.25
CO	15,576	0	15,576
VOC	1,455.5	0	1,455.5

Since QNEC values are entered in PAS database as whole numbers, QNEC will be distributed in four quarters as summarized in the table below:

Pollutant	Quarterly NEC [QNEC]			
	1 st Quarter	2 nd Quarter	3 rd Quarter	4 th Quarter
NOx	1,786	1,786	1,786	1,786
SOx	156	156	156	157
PM ₁₀	262	262	262	263
CO	15,576	15,576	15,576	15,576
VOC	1,455	1,455	1,456	1,456

C-8980-3-0 (Backup Flare):

Quarterly PE2 (lb/qtr) = PE2 (lb/yr) ÷ 4 qtr/yr

Pollutant	Annual PE2 (lb/yr)	Quarterly PE2 (lb/qtr)
NOx	986	246.5
SOx	94	23.5
PM ₁₀	116	29
CO	4,495	1,123.75
VOC	914	228.5

Quarterly PE1 (lb/qtr) = PE1 (lb/yr) ÷ 4 qtr/yr = 0 since these are new emission units.

Thus: QNEC (lb/qtr) = Quarterly PE2 (lb/qtr) – Quarterly PE1 (lb/qtr)

Quarterly NEC [QNEC]			
Pollutant	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NOx	246.5	0	246.5
SOx	23.5	0	23.5
PM ₁₀	29	0	29
CO	1,123.75	0	1,123.75
VOC	228.5	0	228.5

Since QNEC values are entered in PAS database as whole numbers, QNEC will be distributed in four quarters as summarized in the table below:

Pollutant	Quarterly NEC [QNEC]			
	1 st Quarter	2 nd Quarter	3 rd Quarter	4 th Quarter
NOx	246	246	247	247
SOx	23	23	24	24
PM ₁₀	29	29	29	29
CO	1,123	1,124	1,124	1,124
VOC	228	228	229	229

APPENDIX D

BACT Analysis for Syngas-Fired IC Engines (C-8980-1-0 and '-2-0)

**San Joaquin Valley
Unified Air Pollution Control District**

Best Available Control Technology (BACT) Guideline 3.3.14

Emission Unit: Spark-Ignited Syngas*-
Fired IC Engines

Industry Type: Biomass Gasification

Last Update: Date of finalizing project

Equipment Rating:

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO _x	9 ppmvd @ 15% O ₂ (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)	5 ppmvd @ 15% O ₂	
PM ₁₀	= or < 0.03 g/bhp-hr with syngas conditioning system (wet scrubbers, cartridge filters, or equivalent) and positive crankcase ventilation		
VOC	25 ppmvd @ 15% O ₂		

**Syngas (synthetic gas) is derived from biomass (agricultural waste) by gasification or similar processes. Syngas is distinguished from waste gases by its low methane content (less than 5%) and comparatively high hydrogen gas content (15% or greater), although frequently over half of the syngas composition is non-combustible gases such as nitrogen and carbon dioxide.*

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

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

BACT Determination for Syngas-Fired Lean-Burn IC Engines:

As shown in Section VIII of this document, under District Rule 2201 discussion, BACT is triggered for NO_x, PM₁₀, and VOC emissions for each syngas-fired lean-burn IC engine. The District's BACT Clearinghouse currently includes a BACT Guideline 3.3.14 for full-time syngas-fired rich-burn IC engines. However, no BACT Guideline currently exists for full-time syngas-fired lean-burn IC engines. Therefore, a new BACT determination will be made in order to address NO_x, PM₁₀, and VOC emissions from the full-time syngas-fired lean-burn IC engines. Since both rich-burn and lean-burn syngas-fired IC engines essentially belong to the same class and source category, no new BACT Guideline will be established, instead the current BACT Guideline 3.3.14 will be updated to address the lean-burn technology for streamlining purposes.

1) Top-Down BACT Analysis for NO_x Emissions

Step 1 – Identify All Possible Control Technologies

The following control options can be identified as possible control technologies for this class and category based on current BACT Guideline 3.3.14:

1. 9 ppmvd NO_x @ 15% O₂, syngas-fired lean-burn IC engine with SCR system – (Achieved in Practice)
2. 5 ppmvd NO_x @ 15 % O₂, syngas-fired lean-burn IC engine with SCR system – (Technologically Feasible)

Option 1 has been previously determined as achieved in practice for full-time syngas-fired rich-burn IC engines using an air-to-fuel ratio controller and a 3-way catalyst. In addition, the use of a lean-burn technology with SCR is also considered achieved in practice for waste gas-fired IC engines (BACT Guideline 3.3.15) to achieve 10 ppmvd @ 15% O₂ (equivalent to 0.15 g/bhp-hr). However, no source test data is available for a lean-burn syngas-fired IC engines to justify setting a limit lower than 9 ppmvd NO_x @ 15% O₂. Since use of SCR has been a proven technology and based on the manufacturer's guarantee, NO_x emissions of 9 ppmvd @ 15% O₂ will be set as achieved in practice for full-time syngas-fired rich-burn IC engines with SCR.

Option 2 above has been listed as achieved in practice for fossil fuel-fired IC engines under BACT Guideline 3.3.12. This emission level could be achieved by using a larger selective catalytic reduction system for a lean-burn engine. Since no source test data is available, this control will be listed as a possible technologically feasible control option for this project.

Note that for the following BACT analysis, control options will be listed for NO_x emissions in units of ppmvd @ 15% O₂. This would help in comparing control options under different BACT guidelines because different fuel gases have different F-factor and physical properties and will have different equivalent emission limits in the units of b/bhp-hr.

Step 2 – Eliminate Technologically Infeasible Options

Both control options listed in Step 1 are technologically feasible, so no control needs to be eliminated from Step 1.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. 5 ppmvd NO_x @ 15 % O₂, syngas-fired lean-burn IC engine with SCR system – (based on BACT Guideline 3.3.12)
2. 9 ppmvd NO_x @ 15% O₂ (lean-burn IC engine with SCR, rich-burn IC engine with 3-way catalyst, or other equivalent)

Step 4 – Cost Effectiveness Analysis

1. Cost Effective Thresholds:

The District's BACT Policy (APR 1305) establishes annual cost effective thresholds for the required controls based upon the amount of emission reductions achieved by the controls. If the cost of a control is at or below the threshold, the control is considered cost effective. If the cost exceeds the threshold, it is not considered cost effective and the control is not required. In May of 2008, the District updated the BACT cost effective thresholds. The District's cost effective threshold for each pollutant from the May 2008 update is shown in the following table:

BACT Cost Effective Thresholds, May 2008 Update	
Pollutant	Threshold (\$/ton)
NO _x	24,500
CO	300
VOC	17,500
SO _x	18,300
PM ₁₀	11,400

The cost effectiveness (annual cost per ton of pollutant reduced) for a given technologically feasible control option is equal to the annual cost divided by the calculated emission reduction.

Annual costs are equal to annualized cost of utilizing technologically feasible BACT controls on an emission unit that already meets District standard emissions. Annual costs do not include costs necessary to meet District standard emissions. Emission reduction are calculated as follows:

$$\text{Emission Reduction (ton/year)} = \text{District Standard Emissions} - \text{Emissions with tech feasible BACT}$$

2. District Standard Emissions

For new emission units, District standard emissions are equal to the emissions level allowed by applicable District prohibitory rule requirements once the compliance date, i.e. the date at which the emission unit must meet a specific emission requirement, for the rule has passed. As stated under District Rule 4702 discussion in Section VIII of this document, the proposed IC engines are required to meet 11 ppmvd NO_x @ 15% O₂ at the time of installation. Therefore, this emission limit will be used to calculate District standard emissions.

3. Annual Emission Reductions

The technologically feasible option for this class and category of source is identified as 5 ppmvd NOx @ 15% O₂ using a selective catalytic reduction (SCR) system.

The emission reduction for each engine will be calculated as the difference between the technologically feasible emissions and the District standard emissions, as shown below.

District Standard Emissions: 11 ppmvd NOx @ 15% O₂ (equivalent to 0.22 g-NOx/bhp-hr as converted below) – Rule 4702, Table 2, Row 2.e limit

$$\frac{11 \text{ parts-NOx}}{10^6 \text{ parts}} \times \frac{12,100 \text{ ft}^3}{1 \text{ MMBtu}} \times \frac{46 \text{ lb-NOx}}{1 \text{ lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3} \times \frac{\text{MMBtu}}{393.236 \text{ bhp-hr}} \times \frac{453.59 \text{ g-NOx}}{\text{lb-NOx}} \times \frac{\text{Btu}_{\text{in}}}{0.30 \text{ Btu}_{\text{out}}} = 0.22 \frac{\text{g-NOx}}{\text{bhp-hr}}$$

Technologically Feasible Emissions: 5 ppmvd NOx @ 15% O₂ (equivalent to 0.1 g-NOx/bhp-hr, assuming 30% engine efficiency as converted below)

$$\frac{5 \text{ parts-NOx}}{10^6 \text{ parts}} \times \frac{12,100 \text{ ft}^3}{1 \text{ MMBtu}} \times \frac{46 \text{ lb-NOx}}{1 \text{ lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1 \text{ lb-mole}}{379.5 \text{ ft}^3} \times \frac{\text{MMBtu}}{393.236 \text{ bhp-hr}} \times \frac{453.59 \text{ g-NOx}}{\text{lb-NOx}} \times \frac{\text{Btu}_{\text{in}}}{0.30 \text{ Btu}_{\text{out}}} = 0.1 \frac{\text{g-NOx}}{\text{bhp-hr}}$$

$$\begin{aligned} \text{Emission Reduction} &= 0.22 \text{ g-NOx/bhp-hr} - 0.1 \text{ g-NOx/bhp-hr} \\ &= 0.12 \text{ g-NOx/bhp-hr} \end{aligned}$$

The annual emission reduction (in ton/year) for each engine are calculated as follows:

$$\begin{aligned} \text{Annual Emission Reduction} &= \text{Engine Power Rating (bhp)} \times \text{Emission Reduction (g-NOx/bhp-hr)} \times \text{Operation (hr/year)} \div 453.6 \text{ g/lb} \div 2,000 \text{ lb/ton} \\ &= 1,631 \text{ bhp} \times 0.12 \text{ g-NOx/bhp-hr} \times 8,760 \text{ hr/yr} \div 453.59 \text{ g/lb} \div 2,000 \text{ lb/ton} \\ &= 1.89 \text{ ton/year} \end{aligned}$$

4. Annualized Costs

The applicant has stated that it would cost at least \$100,000 to redesign the system to install a bigger catalyst to achieve 5 ppmvd NOx @ 15% O₂. This cost estimate includes only capital cost of the bigger catalyst and associated engineering work and does not include any necessary engine upgrades.

The total cost of achieving the technologically feasible option can be estimated using the assumptions and methods from the cost effectiveness analysis from the August 18, 2011 final draft staff report for the proposed amendments to District Rule 4702⁴. The following table shows the assumptions and calculation of costs for each of the 1,631 bhp IC engines using the cost information provided by the applicant and the assumptions from the August 18, 2011 final draft staff report. The following cost calculations are estimates and likely do not represent the exact cost of installing a bigger SCR system. Additional costs may be incurred. However, since the cost effective determination shows that this option is not cost effective for the engines in this project, no further cost information was gathered.

Cost Multipliers Used for Cost Effectiveness Analysis			
Direct Capital Cost (\$)			
A.	SCR Cost	---	\$100,000
B.	Engine Upgrade	Assume no upgrade for worst case	\$0.00
C.	Auxiliary Equipment (Includes urea tank, air compressor)	---	\$20,000.00
D.	Total Purchased Equipment Cost (PEC)	A+B+C	\$120,000.00
E.	Freight	5% PEC	\$6,000.00
F.	Sales Tax	8.25% PEC	\$9,900.00
G.	Direct Installation Cost	25% PEC	\$30,000.00
H.	Total Direct Capital Cost	D+E+F+G	\$165,900.00
Indirect Capital Cost (\$)			
I.	Facilities	5% PEC	\$6,000.00
J.	Engineering	10% PEC	\$12,000.00
K.	Miscellaneous Costs (system start-up & calibration, piping, stack modifications) 13% PEC plus \$1,500 per day for start-up per equipment installer. Assume one day of start-up	13% PEC + \$1,500	\$17,100.00
L.	Process Contingency	5% PEC	\$6,000.00
M.	Total Indirect Capital Costs	I+J+K+L	\$41,100.00
N.	Project Contingency	20% PEC	\$24,000.00
O.	Total Capital Costs (TCC) (\$)	H+M+N	\$231,000.00
P.	Annualized Capital Cost (\$/yr) (10 years @ 10%)	$0.1627 \times \text{TCC}$	\$37,583.70
Annual O & M Cost (\$/year)			
Q.	Annual Maintenance Labor	16% PEC	\$19,200.00
R.	Annual Reagent Cost (provided by applicant)	\$20,000.00	\$20,000.00
S.	Annual Electricity Cost (set zero for worst case)	---	\$0.00
T.	Total Annual O & M Cost (\$/yr)	Q+R+S	\$39,200.00
TOTAL ANNUALIZED COSTS (\$/YR)		P+W	\$76,783.70

⁴ For reference, the cost effectiveness analysis for the 8/18/11 amendments to Rule 4702 can be found in Table 3, Appendix C of the Final Draft Staff Report for the August 18, 2011 District Governing Board meeting agenda: http://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2011/August/Agenda_Item_10_Aug_18_2011.pdf

5. Cost Effectiveness Determination

The control cost is calculated as the total annualized costs divided by the annual emission reduction as summarized in the following table:

Cost Effectiveness Determination					
Technologically Feasible Option – NOx Emissions					
ATCs #	Total Annualized Costs, \$/yr	Annual Emission Reduction, ton/yr	Control Cost, \$/ton	Cost Effective Threshold, \$/ton	Option Cost Effective?
C-8980-1-0 & '2-0	\$76,783.70	1.89	\$40,626	\$24,500	No

As shown in the table above, the control cost for the technologically feasible option exceeds the cost effectiveness threshold of \$24,500/ton for NOx for each engine in this project; therefore, the technologically feasible option of 5 ppmvd NOx @ 15% O₂ is not cost effective for the proposed engines in this project at this time.

Step 5 – Select BACT

BACT is satisfied by the applicant's proposal to comply with emissions of 9 ppmvd NOx @ 15% O₂ (equivalent to 0.18 g/bhp-hr) with a lean-burn IC engine with SCR system.

2) Top-Down BACT Analysis for PM₁₀ Emissions

Step 1 – Identify All Possible Control Technologies

As calculated in Section VII.C.2 of this evaluation, each IC engine triggers BACT for PM₁₀ emissions, when fired on syngas or alternate fuels (PUC-quality natural gas or propane). Current BACT Guideline 3.3.14 for syngas-fired IC engines does not list any controls for PM₁₀ emissions. A research was conducted of the U.S. Environmental Protection Agency (USEPA) RACT/BACT/LAER Clearinghouse, the California Air Resources Board (CARB) BACT Clearinghouse, as well as San Joaquin Valley APCD, South Coast AQMD, Bay Area AQMD, Sacramento Metropolitan AQMD, and Yolo-Solano AQMD BACT guidelines and rules, and provided no current BACT guidelines for this class and category of equipment.

In the absence of any existing guidelines, the following control can be identified as achieved in practice and as explained below:

1. ≤ 0.03 g-PM₁₀/bhp-hr with syngas conditioning system (wet scrubbers, cartridge filters, or equivalent), and Positive Crankcase Ventilation (PCV) – Achieved in Practice

Control Technology Description:

Syngas Conditioning System:

The facility is proposing a syngas conditioning system prior to being used as fuel in the IC engines. The conditioning system consists of a cyclone, wet scrubbing system, and a cartridge type filter. These controls are expected to remove most of the particulates and condensables. Therefore, particulates contents of the treated syngas is expected to be very low, thus minimizing PM₁₀ emissions from the IC engines.

Positive Crankcase Ventilation (PCV):

The District's current BACT Guidelines 3.1.5 and 3.1.6 for gas-fired emergency IC engines list PCV as an achieved in practice control. In addition, BACT Guideline 3.1.7 for gasoline-fired emergency IC engines lists PCV as a technology feasible option. The District considers PCV system to reduce crankcase VOC and PM₁₀ emissions by at least 90% over an uncontrolled crankcase vent.

A crankcase ventilation system is a one-way passage for gases to escape in a controlled manner from the crankcase of an internal combustion engine. This is necessary because internal combustion inevitably involves a small but continual amount of blow-by, which occurs when some of the gases from the combustion leak past the piston rings (that is, blow by them) to end up inside the crankcase, causing pressure to build up in the crank case. For control of the pressure inside it, a PCV valve is used to vent the crankcase.

PCV does this by using manifold vacuum to draw vapors from the crankcase into the intake manifold. Vapors are then carried with the fuel/air mixture into the combustion chamber where they are burned for second time, thus increasing the fuel efficiency and reducing emissions.

Step 2 – Eliminate Technologically Infeasible Options

There are no technologically infeasible options to eliminate from step 1.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. ≤ 0.03 g-PM₁₀/bhp-hr with syngas conditioning system (wet scrubbers, cartridge filters, or equivalent), and Positive Crankcase Ventilation (PCV) – Achieved in Practice

Step 4 – Cost Effectiveness Analysis

The only control technology in the ranking list from Step 3 is being considered achieved in practice. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

Step 5 – Select BACT

BACT is satisfied by the applicant's proposal to comply with the emission limit of 0.03 g-PM₁₀/bhp-hr with syngas conditioning system (wet scrubbers, cartridge filters, or equivalent), and Positive Crankcase Ventilation (PCV).

3) Top-Down BACT Analysis for VOC Emissions

Step 1 – Identify All Possible Control Technologies

The following possible control technologies are identified:

2. 25 ppmvd @ 15% O₂ (equivalent to 0.17 g/bhp-hr) – (achieved in practice of BACT Guideline 3.3.14 for syngas-fired rich-burn IC engines)
3. 25 ppmvd @ 15% O₂ (equivalent to 0.15 g/bhp-hr) for all spark-ignited IC engines – (achieved in practice of BACT Guideline 3.3.12 for fossil fuel-fired IC engines)
4. 25 ppmvd @ 15% O₂ (equivalent to 0.10 g/bhp-hr) – lean-burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent – (achieved in practice of BACT Guideline 3.3.15 for waste gas-fired IC engines)

Note that all of control options listed above have same VOC emission limit of 25 ppmvd @ 15% O₂, whereas the equivalent emission limits in the units of g/bhp-hr are different. This is because different fuel gases have different F-factor and physical properties.

Step 2 – Eliminate Technologically Infeasible Options

Since all control technologies identified in step 1 have same emission limit of 25 ppmvd @ 15% O₂, essentially there is only one possible technologically feasible control option as follows:

1. 25 ppmvd @ 15% O₂ – (achieved in practice of BACT Guideline 3.3.14 for syngas-fired rich-burn IC engines)

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. 25 ppmvd @ 15% O₂ – (achieved in practice of BACT Guideline 3.3.14 for syngas-fired rich-burn IC engines)

Step 4 – Cost Effectiveness Analysis

The applicant has proposed the only control option from Step 3, which is also considered achieved in practice. Therefore, cost effectiveness analysis is not required.

Step 5 – Select BACT

BACT is satisfied by the applicant's proposal to comply with emissions of 25 ppmvd VOC @ 15% O₂, which is equivalent to 0.17 g/bhp-hr considering the properties of the syngas.

APPENDIX E

BACT Analysis for Syngas-Fired Flare (C-8980-3-0)

**San Joaquin Valley
Unified Air Pollution Control District**

Best Available Control Technology (BACT) Guideline X.X.X

Emission Unit: Syngas*-Fired Flare

Industry Type: Biomass Gasification

Equipment Rating:

Last Update: Date of finalizing project

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO _x	Open flare (0.068 lb/MMBtu)	1. Low NO _x flare (0.024 lb/MMBtu) 2. Enclosed flare (0.041 lb/MMBtu)	
SO _x	0.0065 lb/MMBtu (using a wet scrubbing system or equivalent)		
PM ₁₀	0.008 lb/MMBtu (visible emissions less than Ringelmann ¼ or 5% opacity, except for period(s) not exceeding three minutes in any one hour)		
VOC	Open flare (0.063 lb/MMBtu or 97.7% control)	1. Low VOC flare (0.008 lb/MMBtu or 99.7% control) 2. Enclosed flare (0.0274 lb/MMBtu or 99% control)	

**Syngas (synthetic gas) is derived from biomass (agricultural waste) by gasification or similar processes. Syngas is distinguished from waste gases by its low methane content (less than 5%) and comparatively high hydrogen gas content (15% or greater), although frequently over half of the syngas composition is non-combustible gases such as nitrogen and carbon dioxide.*

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

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

BACT Determination for Syngas-Fired Backup Flare (C-8980-3-0):

As shown in Section VIII of this document, under District Rule 2201 discussion, BACT is triggered for NO_x, SO_x, PM₁₀, and VOC emissions for the syngas-fired backup flare.

Per Permit Services policies and procedures for BACT, a top-down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR rule. For source categories or classes covered in the BACT Clearinghouse, relevant information under each of the analysis steps may simply be cited from the clearinghouse without further analysis.

However, the District's BACT Clearinghouse currently does not include a BACT Guideline that could be applied to this class and category. In addition, all previous BACT Guidelines applicable to the flares have been rescinded and a new project specific BACT must be performed for new and modified flares with the goal to minimize flaring when possible and require low NO_x flares when feasible. Therefore, a new BACT determination will be made for the syngas-fired flare associated with this project.

As discussed in Section I of this document, since the primary function of the backup flare is to dispose of excess syngas when IC engines are not in operation, it is not considered an emissions control device and instead is considered an emissions unit.

1) Top-Down BACT Analysis for NO_x and VOC Emissions

Pursuant to District's BACT Policy APR-1305, if a BACT option controls more than one type of air pollutants, calculate a Multi-Pollutant Cost Effectiveness Threshold (MCET) for the control option. Since the applicant has provided cost data for a low NO_x flare that also reduces VOC emissions, both NO_x and VOC emissions will be evaluated together to calculate MCET as detailed below:

Step 1 – Identify All Possible Control Technologies

The U.S. Environmental Protection Agency (USEPA) RACT/BACT/LAER Clearinghouse, the California Air Resources Board (CARB) BACT Clearinghouse, as well as San Joaquin Valley APCD, South Coast AQMD, Bay Area AQMD, Sacramento Metropolitan AQMD, and Yolo-Solano AQMD BACT guidelines and rules were reviewed to determine potential control technologies for this class and category of operation. Although no directly applicable BACT guidelines or rules were found, the following relevant information was found:

USEPA RACT/BACT/LAER Clearinghouse – Syngas Flares

1. RBLC ID: IN-0166 – Syngas Hydrocarbon Flare, Coal Gasification
 - NO_x limit: 43.09 lb/hr
 - VOC limit: None listed
 - Throughput: 0.27 MMBtu/hr

2. RBLC ID: OH-0317 – Syngas from Coal Gasification
 - NOx limit: None listed
 - VOC limit: None listed
 - Throughput: 21.70 MMBtu/hr
3. RBLC ID: FL-0081 – Syngas from Pet Coke and Coal Gasification
 - NOx limit: 15 ppmvd @ 15% O₂
 - VOC limit: 0.0017 lb/MMBtu
 - Throughput: 1,755 MMBtu/hr
4. RBLC ID: LA-0231 – Hydrocarbon/Gasifier Startup Flare
 - NOx limit: 48.81 lb/hr
 - VOC limit: None listed
 - Throughput: 487.55 MMBtu/hr

As indicated above, the flares listed in the above search results are either very small or very large, so they cannot be compared to the 14.5 MMBtu/hr syngas-fired backup flare proposed with this project. In addition, all results above are for gasification processes not based on woody biomass; therefore, none of the results above can be considered further.

San Joaquin Valley APCD: Syngas-Fired Flares for Woody Biomass Facilities

The District issued ATCs for two electrical generation system based on biomass gasification process under projects N-1082706 and N-1093805. Both operations proposed syngas-fired rich-burn IC engines and syngas-fired backup flares. However, both projects limited emissions from each flare below BACT trigger level. Therefore, BACT was not addressed for the flares under either project and these projects cannot be considered further.

Sacramento Metropolitan AQMD, 1.5 MMBtu/hr Syngas-Fired Thermal Oxidizer from a Municipal Solid Waste

- NOx limit: 1.5 lb/ton of solid waste
- VOC limit: 0.07 lb/ton of solid waste
- Flare Rating: 1.5 MMBtu/hr
- Solid Waste Throughput: 6.5 ton/day

This solid waste gasification process was proposed in the Sacramento Metropolitan AQMD as a pilot test project and did not meet all of the listed emission limits on the permit during the initial source test. So it was removed from the service and never commenced normal operation. In addition, the project never required BACT for the flare or any other units involved with the project as the Sacramento Metropolitan AQMD's BACT trigger threshold was very high at the time of permitting (10 lb/day for NOx, SOx, PM₁₀, and VOC,

and 550 lb/day for CO). Furthermore, this process was based on municipal solid waste and nut shells gasification and used a thermal oxidizer and a waste heat boiler to produce steam used for the power generation. Therefore, this process cannot be compared to the current project and will not be considered further.

Yolo-Solano AQMD: Syngas-Fired Flares for Woody Biomass Facilities

Yolo-Solano AQMD issued ATCs for a research biomass gasification project consisting of a 0.75 MMBtu/hr fluidized bed reactor and a 2.2 MMBtu/hr syngas-fired flare based on woody biomass and herbaceous materials. However, none of the emission units within the project triggered BACT because emissions from each emission unit were below the BACT threshold of 10 lb/day for each pollutant. Therefore, this operation cannot be considered further for BACT determination.

Conclusion:

As indicated in the search above, no comparable processes were found in EPA, ARB, or other California Air Districts' databases for the unique equipment proposed with this project. Therefore, in the absence of specific data, best available information will be utilized for this BACT determination.

The applicant has provided cost information for an Ultra Low Emissions (ULE) syngas-fired flare with low NO_x and VOC emissions. Therefore, based on this information, ULE flare will be considered as one control option. In addition, the District is currently in a process to establish a BACT guideline for waste gas-fired flares utilized in dairy digester gas projects and has identified that an enclosed flare or thermal oxidizers can also be considered as another control option, assuming that such flares could also be used for the syngas-fired flares.

Therefore, based on the available data and information, the following control technology options can be identified:

1. ULE flare (0.024 lb-NO_x/MMBtu and 0.008 lb-VOC/MMBtu) based on the low NO_x burner manufacturer's data.
2. Enclosed flare or direct-fired thermal oxidizer (0.041 lb-NO_x/MMBtu and 0.0274 lb-VOC/MMBtu) based on waste-gas fired flare BACT determination.
3. Open type smokeless flare (0.068 lb-NO_x/MMBtu and 0.063 lb-VOC/MMBtu) – proposed by the applicant

For control option 1, NO_x and VOC emission levels were provided by the low NO_x flare manufacturer. The low NO_x flare is designed on the principle of increased air/fuel mixing to lower the combustion temperature, thus reducing NO_x formation. The low NO_x flare will utilize a variable frequency drive air fan to carefully control the amount of the combustion air. The syngas will enter via an injector into an air/fuel mixing chamber that is designed with static mixers to promote mixing by inducing increased swirl patterns. This causes the syngas to flow turbulently across the air stream to start the mixing process. The waste gas and air mixture is allowed to propagate up the diffuser and into the head of the burner. The head of the burner is covered with a proprietary burner cloth. The cloth is made up of fibers of FeCr

alloy that are knitted together like a wool sweater. This generates a material with millions of tortured paths for the gases to pass through. This is the final and most critical phase of the mixing process, just prior to combustion.

For control option 2, NO_x and VOC emission levels are based on the recent BACT determination for waste gas-fired flares from dairy digesters. That BACT determination referenced a VOC destruction efficiency of 99% for the enclosed flares or thermal oxidizers and 97.7% for the open type flares, as a District practice. Based on a 97.7% control efficiency, the uncontrolled VOC emissions from open flares are calculated as:

$$\begin{aligned}\text{Uncontrolled VOC emissions – open flare} &= (0.063 \text{ lb-VOC/MMBtu}) / (1 - 0.977) \\ &= 2.74 \text{ lb-VOC/MMBtu}\end{aligned}$$

Therefore, the corresponding control emissions for enclosed flare or thermal oxidizers are calculated as:

$$\begin{aligned}\text{Controlled VOC emissions – enclosed flare} &= (2.74 \text{ lb-VOC/MMBtu}) \times (1 - 0.99) \\ &= 0.0274 \text{ lb-VOC/MMBtu}\end{aligned}$$

Alternate Basic Equipment: None

Control Technology Descriptions

Open Flare

A flare is a combustion device in which organic compounds such as VOC and methane are thermally oxidized into carbon dioxide and water, with the production of small quantities of combustion byproducts such as NO_x, SO_x, PM, and CO.

An open flare consists of a stack (typically vertical/elevated) with a pilot/ignition system at the tip. Gas to be flared is piped into the flare from the base and is burned as it exits at the stack tip. The stack diameter and height are chosen based on the anticipated maximum gas flow rate and availability of space to disperse radiant heat and combustion byproducts. The higher the gas flow rate, the greater the required stack diameter; and the closer the flare is to personnel, buildings or other structures, the higher the required stack elevation. The stack tip may be equipped with various types of weather shrouds or shields for improved flame stability.

Pursuant to current District practice, a VOC control efficiency of 97.7% and a NO_x emission limit of 0.068 lb/MMBtu will be considered generally representative of the syngas-fired open type smokeless flares.

Enclosed Flare

An enclosed flare consists of gas burners at or near ground level, which are located at the base of a refractory-lined chimney-type combustion chamber. The combustion chamber completely encloses the burners and the flame, and also enables the combustion process to proceed more completely (i.e. increased residence time). As the exhaust exits at the top of the combustion chamber, a draft that naturally draws in combustion air from the bottom is created. The size (height and width/length or diameter) of the combustion chamber is

determined by the required flaring capacity and the emissions specifications to be met.

The data available in the EPA's RBLC indicate that enclosed flares have already been required to attain a VOC control efficiency of 98% and a NO_x emissions limit of 0.041 lb/MMBtu as indicated below:

USEPA RACT/BACT/LAER Clearinghouse – 19.320 Digester and Landfill Gas Flares

1. RBLC ID: AZ-0042 (Other) – Enclosed Flare, Landfill Gas
 - NO_x limit: 0.041 lb/MMBtu
2. RBLC ID: CA-0440 (BACT-PSD) – 30 MMBtu/hr Enclosed Flare, Landfill Gas
 - VOC/NMHC limit: 98% efficiency, 20 lb/day
 - NO_x limit: 0.06 lb/MMBtu

Pursuant to AP-42, Table 2.4-3 (October 2008 draft), the NMOC and VOC control efficiency (%) range for enclosed flares is 86 – 99+%. Even though the RBLC and AP-42 data are for landfill gas flares, it is not unreasonable to expect that the same emission standards can be attained with syngas, given the proper design and/or operation adjustments. This assumption is supported by the fact that flare manufacturers consistently stress that all flares are custom designed and sized on project-specific basis, taking into consideration the parameters of the gas to be flared and the required performance and/or regulatory requirements to be met.

Based on the available data and information, a VOC control efficiency of 99% (equivalent to 0.0274 lb-VOC/MMBtu) and a NO_x emission limit of 0.041 lb/MMBtu will be considered generally representative of this category of flares.

Thermal Oxidizer

A thermal oxidizer is also an enclosed combustion device in which organic compounds are oxidized at high temperatures (>1,400 °F) in a refractory-lined combustion chamber to produce carbon dioxide, water, and small quantities of combustion byproducts such as NO_x, SO_x, and CO. The combustion chamber is sized to provide sufficient residence time (typically ~ 0.5 sec.). The chamber temperature is maintained by the heat produced by oxidation of the organic pollutants, in addition to an auxiliary fuel such as natural gas. Thus the basic characteristic of a thermal oxidizer is high combustion temperature. However, syngas is a very low calorific value fuel with a higher heating value of only 132 Btu/scf. In addition, the applicant is not proposing to use a backup fuel, such as natural gas. Therefore, syngas by itself cannot attain a high combustion temperature as required by a thermal oxidizer; therefore, the control option of thermal oxidizer will not be considered further.

Step 2 – Eliminate Technologically Infeasible Options

As indicated above, a thermal oxidizer cannot be considered a technologically feasible option due to low higher heating value of syngas and the absence of a backup fuel. Therefore, the thermal oxidizer will be eliminated and the following technologies will be considered technologically feasible:

1. ULE flare (0.024 lb-NOx/MMBtu and 0.008 lb-VOC/MMBtu) based on the low NOx burner manufacturer's data.
2. Enclosed flare (0.041 lb-NOx/MMBtu and 0.0274 lb-VOC/MMBtu) based on waste-gas fired flare BACT determination.
3. Open type flare (0.068 lb-NOx/MMBtu and 0.063 lb-VOC/MMBtu) – proposed by the applicant

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. ULE flare (0.024 lb-NOx/MMBtu and 0.008 lb-VOC/MMBtu) based on the low NOx burner manufacturer's data.
2. Enclosed flare (0.041 lb-NOx/MMBtu and 0.0274 lb-VOC/MMBtu) based on waste-gas fired flare BACT determination.
3. Open type flare (0.068 lb-NOx/MMBtu and 0.063 lb-VOC/MMBtu) – proposed by the applicant

Step 4 – Cost Effectiveness Analysis

Pursuant to the District's BACT policy, if a BACT option controls more than one type of air pollutants, a Multi-Pollutant Cost Effectiveness Threshold (MCET) is calculated for the control option. For this project MCET for NOx and VOC emissions is calculated as below:

$$\begin{aligned}\text{MCET} &= [\text{NOx reduction (tons-NOx/yr)} \times \text{NOx Cost Effective Threshold (\$/ton-NOx)} \\ &\quad + [\text{VOC reduction (tons-VOC/yr)} \times \text{VOC Cost Effective Threshold (\$/ton-VOC)}] \\ &= [\text{NOx reduction (tons-NOx/yr)} \times (\$24,500/\text{ton-NOx}) \\ &\quad + [\text{VOC reduction (tons-VOC/yr)} \times (\$17,500/\text{ton-VOC})]\end{aligned}$$

Whereas, emission reductions for each of NOx and VOC emissions are calculated as below:

$$\text{Emissions Reduction} = \text{District Standard Emissions (DSE)} - \text{Emissions (w/tech feasible BACT) (tons/year)}$$

MCET for each of the first two control options is calculated as below:

SOx Emissions:

Since SOx emissions are based on mass balance, assuming that any sulfur present in the syngas will be converted to SOx, the use of a low NOx or an enclosed flare will have no significant effect on SOx emissions. Therefore, SOx emissions are not included in the MCET analysis.

PM₁₀ Emissions:

The available data and information indicate that both open and enclosed flares generally achieve near complete combustion given good quality vent gas and good combustion conditions. PM₁₀ emissions are thus assumed not to be significantly affected by the type of the flare used. Therefore, PM₁₀ emissions are not included in the MCET analysis.

I. ULE Flare (0.024 lb-NOx/MMBtu and 0.008 lb-VOC/MMBtu)

A. Cost

The applicant has provided the capital cost of \$268,700.00 to install a ULE flare. This is the equipment capital cost only and includes the cost of a low NOx flare, a combustion air blower with a variable frequency drive, a control panel, and accessory equipment. This cost does not include the cost of shipping, technical assistance fee during commissioning, any related costs, or the ongoing operation and maintenance costs.

Therefore, no operation costs will be evaluated for this control option, as shown below that the equipment capital cost alone makes this control option not cost effective.

The equivalent annual cost is calculated as shown below:

$$A = P \frac{i(1+i)^n}{(1+i)^n - 1} \text{ where:}$$

A = equivalent annual control equipment capital cost

P = present value of the control equipment, including installation cost

i = interest rate (generally assumed to be 10%, unless the applicant demonstrates that a different rate is more representative of the specific operation)

n = equipment life (generally assumed to be 10 years, unless the applicant demonstrates that a different rate is more representative of the specific operation)

$$\begin{aligned} A &= \$268,700 \frac{0.1(1+0.1)^{10}}{(1+0.1)^{10} - 1} \\ &= \$43,730 \end{aligned}$$

B. Emissions Reduction Cost

Emission reduction cost for each of NOx and VOC emissions are calculated as follows:

NOx

First, District Standard Emissions (DSE) are calculated as follows:

Assumptions:

- Flare rating = 14.5 MMBtu/hr
- Emission Factor = 0.068 lb-NOx/MMBtu
- Operation = 1,000 hr/year

Thus,

$$\begin{aligned}\text{DSE} &= \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/year)} \\ &= 14.5 \text{ MMBtu/hr} \times 0.068 \text{ lb-NOx/MMBtu} \times 1,000 \text{ hr/year} \\ &= 986 \text{ lb-NOx/year} \div 2,000 \text{ lb/ton} \\ &= 0.49 \text{ ton-NOx/year}\end{aligned}$$

Next, Emissions with Tech Feasible (ETF) option are calculated as follows:

Assumptions:

- Flare rating = 14.5 MMBtu/hr
- Emission Factor = 0.024 lb-NOx/MMBtu
- Operation = 1,000 hr/year

Thus,

$$\begin{aligned}\text{ETF} &= \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/year)} \\ &= 14.5 \text{ MMBtu/hr} \times 0.024 \text{ lb-NOx/MMBtu} \times 1,000 \text{ hr/year} \\ &= 348 \text{ lb-NOx/year} \div 2,000 \text{ lb/ton} \\ &= 0.17 \text{ ton-NOx/year}\end{aligned}$$

Now emission reductions are calculated as:

$$\begin{aligned}\text{Emissions Reduction} &= \text{DSE (tons/year)} - \text{ETF (tons/year)} \\ &= 0.49 \text{ ton-NOx/year} - 0.17 \text{ ton-NOx/year} \\ &= 0.32 \text{ ton-NOx/year}\end{aligned}$$

VOC

First, District Standard Emissions (DSE) are calculated as follows:

Assumptions:

- Flare rating = 14.5 MMBtu/hr
- Emission Factor = 0.063 lb-VOC/MMBtu
- Operation = 1,000 hr/year

Thus,

$$\begin{aligned}\text{DSE} &= \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/year)} \\ &= 14.5 \text{ MMBtu/hr} \times 0.063 \text{ lb-VOC/MMBtu} \times 1,000 \text{ hr/year} \\ &= 914 \text{ lb-VOC/year} \div 2,000 \text{ lb/ton} \\ &= 0.46 \text{ ton-VOC/year}\end{aligned}$$

Next, Emissions with Tech Feasible (ETF) option are calculated as follows:

Assumptions:

- Flare rating = 14.5 MMBtu/hr
- Emission Factor = 0.008 lb-VOC/MMBtu
- Operation = 1,000 hr/year

Thus,

$$\begin{aligned}\text{ETF} &= \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/year)} \\ &= 14.5 \text{ MMBtu/hr} \times 0.008 \text{ lb-VOC/MMBtu} \times 1,000 \text{ hr/year} \\ &= 116 \text{ lb-VOC/year} \div 2,000 \text{ lb/ton} \\ &= 0.06 \text{ ton-VOC/year}\end{aligned}$$

Now emission reductions are calculated as:

$$\begin{aligned}\text{Emissions Reduction} &= \text{DSE (tons/year)} - \text{ETF (tons/year)} \\ &= 0.46 \text{ ton-VOC/year} - 0.06 \text{ ton-VOC/year} \\ &= 0.4 \text{ ton-VOC/year}\end{aligned}$$

Multi-Pollutant Cost Effective Threshold (MCET) Calculations:

Since this control option reduces both NO_x and VOC emissions, the multi-pollutant cost effectiveness threshold (MCET) will be used to determine cost effectiveness.

$$\begin{aligned}\text{MCET} &= [(0.32 \text{ tons-NO}_x\text{/yr}) \times (\$24,500\text{/ton-NO}_x)] \\ &\quad + [(0.4 \text{ tons-VOC/yr}) \times (\$17,500\text{/ton-VOC})] \\ &= \$14,840\text{/yr}\end{aligned}$$

Based on the minimum possible capital cost, and not taking recurring annual operating costs into consideration, the total annual cost of \$43,730 (calculated in Step 4, Section I.A above) for reductions from a low NO_x flare is greater than the MCET. This control option is therefore not cost effective and is removed from further consideration.

II. Enclosed Flare (0.041 lb-NOx/MMBtu and 0.0274 lb-VOC/MMBtu)

A. Cost

A capital cost for an enclosed flare of \$150,000 will be used based on the recent BACT determination for the waste gas-fired flares under District project C-1162455. This cost does not include the cost of any accessory equipment, cost of installation, and the ongoing operation and maintenance costs.

Therefore, no operation costs will be evaluated for this control option, as shown below that the equipment capital cost alone makes this control option not cost effective.

The equivalent annual cost is calculated as shown below:

$$A = P \frac{i(1+i)^n}{(1+i)^n - 1} \text{ where:}$$

A = equivalent annual control equipment capital cost

P = present value of the control equipment, including installation cost

i = interest rate (generally assumed to be 10%, unless the applicant demonstrates that a different rate is more representative of the specific operation)

n = equipment life (generally assumed to be 10 years, unless the applicant demonstrates that a different rate is more representative of the specific operation)

$$\begin{aligned} A &= \$150,000 \frac{0.1(1+0.1)^{10}}{(1+0.1)^{10} - 1} \\ &= \$24,412 \end{aligned}$$

B. Emissions Reduction Cost

Emission reduction cost for each of NOx and VOC emissions are calculated as follows:

NOx

First, District Standard Emissions (DSE) are calculated as follows:

Assumptions:

- Flare rating = 14.5 MMBtu/hr
- Emission Factor = 0.068 lb-NOx/MMBtu
- Operation = 1,000 hr/year

Thus,

$$\begin{aligned}\text{DSE} &= \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/year)} \\ &= 14.5 \text{ MMBtu/hr} \times 0.068 \text{ lb-NOx/MMBtu} \times 1,000 \text{ hr/year} \\ &= 986 \text{ lb-NOx/year} \div 2,000 \text{ lb/ton} \\ &= 0.49 \text{ ton-NOx/year}\end{aligned}$$

Next, Emissions with Tech Feasible (ETF) option are calculated as follows:

Assumptions:

- Flare rating = 14.5 MMBtu/hr
- Emission Factor = 0.041 lb-NOx/MMBtu
- Operation = 1,000 hr/year

Thus,

$$\begin{aligned}\text{ETF} &= \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/year)} \\ &= 14.5 \text{ MMBtu/hr} \times 0.041 \text{ lb-NOx/MMBtu} \times 1,000 \text{ hr/year} \\ &= 595 \text{ lb-NOx/year} \div 2,000 \text{ lb/ton} \\ &= 0.30 \text{ ton-NOx/year}\end{aligned}$$

Now emission reductions are calculated as:

$$\begin{aligned}\text{Emissions Reduction} &= \text{DSE (tons/year)} - \text{ETF (tons/year)} \\ &= 0.49 \text{ ton-NOx/year} - 0.30 \text{ ton-NOx/year} \\ &= 0.19 \text{ ton-NOx/year}\end{aligned}$$

VOC

First, District Standard Emissions (DSE) are calculated as follows:

Assumptions:

- Flare rating = 14.5 MMBtu/hr
- Emission Factor = 0.063 lb-VOC/MMBtu
- Operation = 1,000 hr/year

Thus,

$$\begin{aligned}\text{DSE} &= \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/year)} \\ &= 14.5 \text{ MMBtu/hr} \times 0.063 \text{ lb-VOC/MMBtu} \times 1,000 \text{ hr/year} \\ &= 914 \text{ lb-VOC/year} \div 2,000 \text{ lb/ton} \\ &= 0.46 \text{ ton-VOC/year}\end{aligned}$$

Next, Emissions with Tech Feasible (ETF) option are calculated as follows:

Assumptions:

- Flare rating = 14.5 MMBtu/hr
- Emission Factor = 0.0274 lb-VOC/MMBtu
- Operation = 1,000 hr/year

Thus,

$$\begin{aligned}\text{ETF} &= \text{Rating (MMBtu/hr)} \times \text{EF (lb/MMBtu)} \times \text{Operation (hr/year)} \\ &= 14.5 \text{ MMBtu/hr} \times 0.0274 \text{ lb-VOC/MMBtu} \times 1,000 \text{ hr/year} \\ &= 397 \text{ lb-VOC/year} \div 2,000 \text{ lb/ton} \\ &= 0.20 \text{ ton-VOC/year}\end{aligned}$$

Now emission reductions are calculated as:

$$\begin{aligned}\text{Emissions Reduction} &= \text{DSE (tons/year)} - \text{ETF (tons/year)} \\ &= 0.46 \text{ ton-VOC/year} - 0.20 \text{ ton-VOC/year} \\ &= 0.26 \text{ ton-VOC/year}\end{aligned}$$

Multi-Pollutant Cost Effective Threshold (MCET) Calculations:

Since this control option reduces both NO_x and VOC emissions, the multi-pollutant cost effectiveness threshold (MCET) will be used to determine cost effectiveness.

$$\begin{aligned}\text{MCET} &= [(0.19 \text{ tons-NO}_x\text{/yr}) \times (\$24,500\text{/ton-NO}_x)] \\ &\quad + [(0.26 \text{ tons-VOC/yr}) \times (\$17,500\text{/ton-VOC})] \\ &= \$9,205\text{/yr}\end{aligned}$$

Based on the minimum possible capital cost, and not taking recurring annual operating costs into consideration, the total annual cost of \$24,412 (calculated in Step 4, Section II.A above) for reductions from an enclosed flare is greater than the MCET. Therefore, this control option is not cost effective and is removed from further consideration.

III. Open Type Flare

Since this control option is considered achieved in practice and has been proposed, a cost effectiveness analysis is not required.

Step 5 – Select BACT

BACT is satisfied by the applicant's proposal of an open type flare with NO_x emissions of 0.068 lb/MMBtu and VOC emissions of 0.063 lb/MMBtu.

2) Top-Down BACT Analysis for SOx Emissions

Step 1 – Identify All Possible Control Technologies

As previously stated under Top-Down BACT analysis for NOx and VOC emissions, no BACT information is available for a comparable operation. The facility has proposed to use a cyclone, followed by a wet scrubbing system to condition syngas prior to incineration of the excess syngas in the proposed flare. These controls are expected to remove most of the particulates and condensables from the produced syngas. Since oxides of sulfur are water soluble, the proposed water scrubbers are expected to lower SOx emissions below the permitted levels.

In the absence of any source test data for the similar operation, there is no justification to require a lower emission factor or a higher level of control. Therefore, based on the available information, the following control option can be identified as achieved in practice, as this control is expected to keep SOx emission below the permitted level:

1. SOx emissions of 0.0065 lb/MMBtu – syngas treatment with wet scrubbing system – Achieved in Practice

Step 2 – Eliminate Technologically Infeasible Options

The only control technology in Step 1 is considered achieved in practice, so no control technology need to be eliminated from Step 1.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Since there is only one control option remaining in Step 2, no need for ranking.

Step 4 – Cost Effectiveness Analysis

The applicant has proposed the only control option from Step 3, which is also considered achieved in practice. Therefore, cost effectiveness analysis is not required.

Step 5 – Select BACT

BACT is satisfied for SOx emissions by the applicant's proposal to condition syngas using a wet scrubbing system and emission factors of 0.0065 lb-SOx/MMBtu.

3) Top-Down BACT Analysis for PM₁₀ Emissions

Step 1 – Identify All Possible Control Technologies

As previously stated under Top-Down BACT analysis for NO_x and VOC emissions, no BACT information is available for a comparable operation. The facility has proposed to use a cyclone, followed by a wet scrubbing system to condition syngas prior to feeding to the syngas-fired IC engines or incineration of excess syngas in the proposed flare. These controls are expected to remove most of the particulates and condensables from the produced syngas. Therefore, PM₁₀ emissions are expected to be below the permitted levels.

Open Flare with Smokeless Operation:

PM₁₀ emissions are primarily a product of incomplete combustion. Smoke, which is composed of soot (i.e. unburned carbon particles) is used as an indicator of the completeness of combustion. Thus, smokeless flares, or those that are smoking only very lightly, can be considered to be achieving complete or nearly complete combustion, which corresponds to the lowest PM₁₀ emission rates.

Pursuant to AP-42 Section 13.5 (December 2016), smokeless flares emit 0 micrograms of soot per liter of exhaust and lightly smoking flares emit 40 micrograms of soot per liter of exhaust. Based on this information, the District has previously established PM₁₀ emission factors of 0.008 lb/MMBtu (equivalent to 10 micrograms of soot per liter of exhaust) for flares subject to a visible emissions limit of Ringelmann ¼ or 5% opacity (except for period(s) not exceeding three minutes in any one hour); and 0.026 lb/MMBtu (equivalent to 40 micrograms of soot per liter of exhaust) for flares subject to a visible emissions limit of Ringelmann 1 or 20% opacity (except for period(s) not exceeding three minutes in any one hour).

Smokeless combustion is used as a primary indicator of proper flare function and optimum control efficiency. AP-42 (12/16), Section 13.5-1 states that smoking may result from combustion, depending upon waste gas components and the quantity and distribution of combustion air. Waste gases containing methane, hydrogen, CO, and ammonia usually burn without smoke, whereas waste gases containing heavy hydrocarbons such as paraffins above methane, olefins, and aromatics, have a higher tendency to smoke. Since syngas is primarily hydrogen (~19% H₂) and carbon monoxide (~19% CO) with only about 2% methane, it is expected to burn smokeless, as long as the flare is properly designed to increase the air/fuel mixing. As AP-42, Section 13.5-1 further states that an external momentum force, such as steam injection or blowing air, is used for efficient air/waste gas mixing and turbulence, which promotes smokeless flaring of heavy hydrocarbon waste gas. Other external forces may be used for this purpose, including water spray, high velocity vortex action, or natural gas. The facility is not proposing to use any backup fuel, instead, it is expected that with the proper design to increase air/syngas mixing, the proposed flare can achieve smokeless operation.

In the absence of any source test data for the similar operation, there is no justification to require a lower emission factor or a higher level of control. Therefore, based on the available information, the following control option can be identified as achieved in practice, as this control is expected to keep PM₁₀ emission below the permitted level:

1. PM₁₀ emissions of 0.008 lb/MMBtu (visible emissions less than Ringelmann ¼ or 5% opacity, except for period(s) not exceeding three minutes in any one hour) – Achieved in Practice

Step 2 – Eliminate Technologically Infeasible Options

The only control technology in Step 1 is considered achieved in practice, so no control to be eliminated from Step 1.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Since there is only one control option remaining in Step 2, no need for ranking.

Step 4 – Cost Effectiveness Analysis

The applicant has proposed the only control option from Step 3, which is also considered achieved in practice. Therefore, cost effectiveness analysis is not required.

Step 5 – Select BACT

BACT is satisfied for PM₁₀ emissions by the applicant's proposal of a PM₁₀ emission limit of 0.008 lb/MMBtu (visible emissions less than Ringelmann ¼ or 5% opacity, except for period(s) not exceeding three minutes in any one hour).

APPENDIX F

HRA and AAQA Summary

San Joaquin Valley Air Pollution Control District

Risk Management Review

To: Sajjad Ahmad – Permit Services

From: Seth Lane – Technical Services

Date: October 31, 2018

Facility Name: North Fork Community Power

Location: 57839 Rd 225 North Fork, CA

Application #(s): C-8980-1-0 thru 3-0

Project #: C-1160156

A. RMR SUMMARY

RMR Summary						
Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required?	Special Permit Requirements?
Unit 1-0 (Syngas Engine w/ option for NG or Propane)	2.41	0.11*	0.00	3.07E-07	No	Yes
Unit 2-0 (Syngas Engine w/ option for NG or Propane)	2.41	0.11*	0.00	3.07E-07	No	Yes
Unit 3-0 (Flare)	0.01	0.00	0.00	6.80E-10	No	No
Project Totals	4.83	0.22	0.01	6.15E-07		
Facility Totals	>1	0.22	0.01	6.15E-07		

* Natural gas (or Propane) cannot be utilized simultaneously with Syngas, therefore Acute risk was determined by taking the worst case risk of either fuel sources.

Proposed Permit Requirements

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Unit # 1-0, & 2-0

1. 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.
2. The commissioning period will not exceed 500 hours per year.
3. When fired on PUC-quality natural gas or propane, Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be in operation.
4. Engines under permit units C-8980-1 or -2 shall not be fired at the same time on PUC-quality natural gas or propane for maintenance and testing purposes.

5. Engines under permit units C-8980-1 or -2 shall not be in commissioning period simultaneously.

Unit # 3-0

1. 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.

B. RMR REPORT

I. Project Description

Technical Services received a revised request on October 29, 2018, to perform an Ambient Air Quality Analysis and a Risk Management Review for a proposed installation of a 2.0 MW electrical generation facility using biomass gasification (pyrolysis) process to generate electricity for commercial sale. The proposal is summarized below:

ATCs C-8980-1-0 and '-2-0: The 2.0 MW electrical power generation operation will consist of two lines each with 1.0 MW electrical power generation capacity (ATCs '-1-0 and '-2-0). Each line will consist of a wood chips gasification unit (gasifier) to produce synthetic gas (syngas) by pyrolysis of wood chips from forest waste; a syngas conditioning system consisting of a cyclone, wet scrubbers, a cartridge type filter, and condensate traps; a 1,631 bhp lean-burn syngas-fired IC engine equipped with a Selective Catalyst Reduction (SCR) system and an oxidation catalyst powering an electrical generator; and a permit exempt cooling tower. The facility has also requested to allow the engines to be fired on propane or PUC-quality natural gas for up to 200 hours per year for maintenance and testing purposes and up to 200 hours during commissioning period when syngas is not available. The facility has stated that firing IC engines on alternate fuels will only be conducted when emissions control systems (SCR system and oxidation catalyst) are in operation. This will be enforced by appropriate permit conditions as discussed later in this evaluation.

ATC C-8980-3-0: A 14.5 MMBtu/hr syngas-fired backup flare to dispose of excess syngas produced from permit units '-1 and '-2 during periods of startup and shutdown, and when engines are temporarily out of service. No backup fuel is being proposed with the flare. Since the primary function of the backup flare is to dispose of excess syngas when IC engines are not in operation, it is not considered an emissions control device and instead is considered an emissions unit.

The operation will also include the following permit exempt equipment:

- Wood chips receiving and storage operation,
- Wood chip drying operation, and
- Two cooling towers, one associated with each permit unit '-1-0 and '-2-0

II. Analysis

Toxic Emissions for Unit 1-0 and 2-0 (Syngas Engines) were calculated utilizing the amount of methane (2%) in the Syngas and applying that amount of the engine process rate to the 2000 AP42 emission factors for Natural Gas Fired internal combustion 4 Stroke Lean Burn Engine. (The use of a catalyst reduces TACs by 76% (NESHAP). Pyrolysis emissions assumes 0.01% is not captured by the scrubbers and filters. The inefficiency of 0.01% was applied to the District approved emission factors based on the 2003 AP 42 chapter 1 section 6 Wood Residue Combustion in Boilers. The emissions for Ammonia emitted in the syngas operation were calculated and provided by the processing engineer.

To account for the commissioning period, the catalyst was not considered, using the 2000 AP42 emission factors for Natural Gas Fired internal combustion 4 Stroke Lean Burn Engine, for a total of 500 hours per year.

To account for Unit 1-0 and 2-0 while using PUC-quality natural gas or propane, toxic emissions were calculated using 2000 AP42 emission factors for Natural Gas Fired internal combustion 4 Stroke Lean Burn Engine. (The use of a catalyst reduces TACs by 76% (NESHAP).

Toxic Emissions for Unit 3-0 (Syngas Flare) were calculated by determining the amount of methane (2%) and applying that amount of the engine process rate to the 2001 Ventura County's Air Pollution Control District's emission factors for Natural Gas Fired external combustion.

These emissions were then input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required. The AERMOD model was used, with the parameters outlined below and meteorological data for 2006-2009 from Porterville to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 1-0 & 2-0 EACH (Wood Gasification Process / Syngas Engine)			
Source Type	Point	Location Type	Rural
Stack Height (m)	9.14	Closest Receptor (m)	210
Stack Diameter. (m)	0.51	Type of Receptor	Business
Stack Exit Velocity (m/s)	7.42	Max Hours per Year	8760
Stack Exit Temp. (°K)	773	Fuel Type	Syngas
Fuel Usage (mmscf/hr)	6.48E-02	Fuel Usage (mmscf/yr)	568
Wood Throughput (ton/hr)	2	Wood Throughput (ton/yr)	10,000
NH3 Emissions (lb/hr)	0.24	NH3 Emissions (lb/yr)	1,955
Fuel Usage During Commissioning (mmscf/yr)	32.4	NH3 Emissions During Commissioning (lb/yr)	121

Analysis Parameters Unit 1-0 & 2-0 EACH (Engine while using Natural Gas or Propane)			
Source Type	Point	Location Type	Rural
Stack Height (m)	9.14	Closest Receptor (m)	210
Stack Diameter. (m)	0.51	Type of Receptor	Business
Stack Exit Velocity (m/s)	7.42	Max Hours per Year	200
Stack Exit Temp. (°K)	773	Fuel Type	Natural Gas
Fuel Usage (mmscf/hr)*	0.01	Fuel Usage (mmscf/yr)*	2.28
NH3 Emissions (lb/hr)	0.24	NH3 Emissions (lb/yr)	49

*The NG scf is converted into a lower value than the syngas scf. This is because the NG gas has a higher heat rating, therefore less fuel is required to create the energy. Thus, the flowrate is reduced.

Analysis Parameters Unit 3-0 (Syngas Flare)			
Source Type	Point	Location Type	Rural
Stack Height (m)	7.9	Closest Receptor (m)	210
Stack Diameter. (m)	0.66	Type of Receptor	Business
Stack Exit Velocity (m/s)	20	Max Hours per Year	8760
Stack Exit Temp. (°K)	1,273	Fuel Type	Syngas
Fuel Usage (mmscf/hr) ¹	2.80E-04	Fuel Usage (mmscf/yr) ¹	0.28

¹This represents the hourly and yearly process rates multiplied by the percent of methane in the syngas, 0.02.

Technical Services performed modeling for criteria pollutants CO, NO_x, SO_x, and PM₁₀ with the emission rates below:

Unit #	NO _x (Lbs.)		SO _x (Lbs.)		CO (Lbs.)		PM ₁₀ (Lbs.)	
	Hr.	Yr.	Hr.	Yr.	Hr.	Yr.	Hr.	Yr.
1-0	0.65	5,217	0.07	580	4.39	N/A	0.11	869
1-0 Commissioning	3.60	1,798	0.07	37	50.14	N/A	0.11	54
1-0 PUC-quality NG or Propane	0.65	129	0.04	9	4.39	N/A	0.63	126
2-0	0.65	5,217	0.07	580	4.39	N/A	0.11	869
2-0 Commissioning	3.60	1,798	0.07	37	50.14	N/A	0.11	54
2-0 PUC-quality NG or Propane	0.65	129	0.04	9	4.39	N/A	0.63	126
3-0	0.99	986	0.09	94	4.50	N/A	0.12	116

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

	Background Site	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Madera Pump Yard (2016)	Pass	X	Pass	X	X
NO _x	Madera Pump Yard (2016)	Pass ¹	X	X	X	Pass
SO _x	Fresno – Garland (2016)	Pass	Pass	X	Pass	Pass
PM ₁₀	Madera - City (2016)	X	X	X	Pass ²	Pass ²
PM _{2.5}	Madera – City (2016)	X	X	X	Pass ³	Pass ³

*Results were taken from the attached PSD spreadsheet.

¹The project was compared to the 1-hour NO₂ National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures. The engines can only operate one fuel source at a given time (NG, Propane, or Syngas). Similarly, Commissioning and Non Commissioning cannot both be in operation on an engine at the same time. Therefore, for hourly Nox, each fuel type was modeled separately and the worst case fuel was analyzed. Commissioning and Non Commissioning was analyzed separately. Hourly Nox passed based on the condition the engines shall not both be operating during Commissioning at the same time.

²The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2). Pm₁₀ 24 hour passed based on the condition the engines shall not be fired at the same time on PUC-quality natural gas or propane for maintenance and testing purposes.

³Modeled PM₁₀ and PM_{2.5} concentrations were below the District SIL for non-fugitive sources of 5 µg/m³ for the 24-hour average concentration and 1 µg/m³ for the annual concentration.

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit requirements listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

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

IV. Attachments

- A. RMR request from the project engineer
- B. Additional information from the applicant/project engineer
- C. Prioritization score w/ toxic emissions summary
- D. Facility Summary
- E. AAQA Reports

APPENDIX G

Uncontrolled Emission Calculations for Permit Exempt Equipment

Uncontrolled Potential Emission Calculations:

1) Wood Chip Receiving and Storage Operation

Wood chips are pre-screened prior to delivery to remove fines and to ensure a uniform chip size to meet facility's biomass feedstock specifications. The moisture content of the wood chips is expected about 50% on arrival. Therefore, prescreening and the high moisture content of the wood chips is expected to reduce the potential for fugitive particulate (PM) emissions during receiving and storage. In addition, storage in open piles with rains and snow events are likely to help wash away any fines. Regardless, uncontrolled PM emissions will be calculated using worst-case assumptions.

A. Assumptions

- This operation involves with particulate (PM) emissions only.
- Operation consists of two emission units: wood chips receiving operation and wood chips storage operation.
- For wood chips receiving operation two Emission Points (EPs) are assumed to calculate potential emissions: first when wood chips are received and the second when they are loaded into process feeding bin using front-end loaders.
- A Bone Dry Ton (BDT) is 2,000 lb of woody material at 0% moisture.
- A Green Ton (GT) is 2,000 lb of woody material at 50% moisture.
- Daily emissions are calculated based on a maximum quantity of 90 BDT of wood chips received per day or loaded into the process receiving bin (per applicant).
- Wood chips are expected to have about 50% moisture on arrival and during storage. However, a moisture content of 1% will be assumed (worst case).
- For a worst case, a maximum stockpile area of 4 acres is assumed (per applicant).

B. Emission Factors (EFs)

a) Wood Chips Receiving Operation

Since no emission factors are available and all emissions are generated due to drops from one point to another, the aggregate drop equation of AP-42 fifth edition, Section 13.2.4-3, (11/06) will be used as the best approximation for wind induced emissions as follows:

$$EF \frac{\text{lbs}}{\text{ton}} = (0.0032) * K * \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where:

EF = Emissions factor for each drop point

K = Particle size multiplier (for PM = 0.74)

U = Mean wind speed (7.5 mph, AP-42, Table 7.1-9 (11/06) for Stockton, CA)

M = Material moisture content (assume 1.0% for a worst case)

Thus:

$$EF = 0.011 \text{ lb-PM/ton}$$

b) Wood Chip Storage Emissions

No emission factor is available for wood chips storage in open storage piles. Section 13.2.4-3, (11/06) of AP-42 indicates that worst-case emissions from storage pile areas occur under dry, windy conditions. Worst-case emissions from materials handling operations may be calculated by substituting into the aggregate drop equation appropriate values for aggregate material moisture content and for anticipated wind speeds during the worst case averaging period, usually 24 hours.

However, as mentioned before, wood chips are received with a high moisture content and will be stored in open piles in area with high average precipitation. So any entrained fine particulates are expected to be washed away and moisture content is expected to be higher than 6% by weight. District practice is to consider materials with moisture content greater than or equal to 6% by weight, as having negligible fugitive emissions due to the extreme water saturation.

C. Uncontrolled Potential to Emit (PE) Calculations

a) Wood Chips Receiving Operation

For the wood chips receiving operation, two Emission Points (EPs) are assumed: first when wood chips are received and the second when they are loaded into the feed hopper using front-end loaders.

Daily uncontrolled PE₂ is calculated as follows:

$$\begin{aligned} \text{Uncontrolled Daily PE} &= \text{Throughput (BDT/day)} \times EF \text{ (lb-PM/BDT/EP)} \times 2 \text{ EP} \\ &= 90 \text{ (BDT/day)} \times 0.011 \text{ (lb-PM/BDT/EP)} \times 2 \text{ EP} \\ &= 2.0 \text{ lb-PM/day} \end{aligned}$$

As shown above, since uncontrolled PE is less than 2.0 lb/day, this operation is not subject to District permits at this time (low emitting unit).

b) Wood Chips Storage Operation

As indicated above, emissions are considered negligible due to high moisture content. Therefore, this operation is not subject to District permits at this time (low emitting unit).

2) Wood Chips Drying Operation

Wood chips drying will be accomplished using recovered waste heat from the two syngas-fired IC engines' exhaust so no additional combustion emissions will be produced from the drying operation. A rotary drum dryer venting to a cyclone collector will be used to dry the wood chips from about 50% moisture on arrival to about 10% moisture. Water vapor and some PM₁₀ will be released from the top of the dryer and the cyclone. The relatively high moisture content and the use of high efficiency cyclone is expected to minimize PM₁₀ emissions. However, uncontrolled potential emissions are calculated using worst case assumptions as follows:

A. Assumptions

- This permit unit involves with particulate (PM) emissions only. The purpose of wood chips drying is to remove extra moisture in excess of 10% at a relatively lower temperature. Therefore, no VOC emissions are generated from this operation.
- The exhaust from the syngas-fired IC engines (permit units C-8980-1-0 and '-2-0) will be ducted to the rotary drum dryer to dry the wood chips. Since these exhaust emissions are already accounted for in IC engine emission calculations under Section VII.C.2 of this document, no additional combustion emissions are generated from this operation.
- Since no emission factor is available for this type of operation, wind induced emission factor for wood chips receiving operation will be used based on a worst case assumption of 1% moisture content by weight.
- Daily uncontrolled potential emissions are calculated based on a maximum wood chips throughput of 90 BDT/day (per applicant).

B. Emission Factors (EFs)

No emission factors for wood chips drying operations are available. Since this operation involves with blowing mildly hot IC engine exhaust over the wood chips in a rotary dryer, the same wind induced emission factor will be used as the best approximation that was calculated for wood chips receiving operation above. Thus:

$$EF = 0.011 \text{ lb-PM/ton}$$

C. Calculations

- Uncontrolled daily potential emissions from the wood chips drying operation are calculated as follows:

$$\begin{aligned}\text{Uncontrolled Daily PE} &= \text{Throughput (BDT/day)} \times EF \text{ (lb-PM/BDT)} \\ &= 90 \text{ (BDT/day)} \times 0.011 \text{ (lb-PM/BDT)} \\ &= 1.0 \text{ lb-PM}_{10}/\text{day}\end{aligned}$$

As shown above, since uncontrolled PE is less than 2.0 lb/day, this operation is not subject to District permits at this time (low emitting unit).

APPENDIX H

Syngas F-Factor Calculations

Syngas F-Factor Calculations:

What is F-Factor?

The combustion F-Factor (or EPA F-Factor) represents the ratio of exhaust air to the heat input of a particular fuel and may be calculated in accordance with the procedures given in EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emission Rates (https://www.epa.gov/sites/production/files/2017-08/documents/method_19.pdf), and also may be calculated based on the equations for complete combustion of the fuel using atmospheric air. Generally, syngas and other waste gas fuels will have higher F-Factors than the F-Factor for natural gas (8,710 dscf/MMBtu @ 25 °C, 8,578 dscf/MMBtu @ 60 °F) because there will be generally a larger volume of fuel required and a higher exhaust flow rate for the same heat input because of the lower Btu content of the gas and because many of the compounds in syngas are not combusted.

Syngas F-Factor will be calculated as follows based on the equations for complete combustion of syngas in ambient air.

F-Factor Calculations

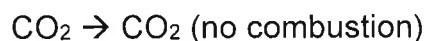
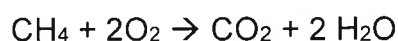
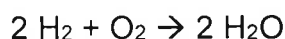
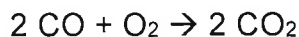
Syngas Composition

Syngas F-factor will be calculated based on the syngas composition as provided by the engine manufacturer and summarized in the table below:

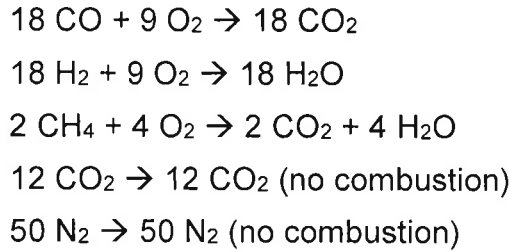
Syngas Component	Composition (%age by weight)
CO	18 (+/- 2%)
H ₂	18 (+/- 2%)
CH ₄	2 %
CO ₂	12 %
N ₂	Balance (50%)

Equations for Combustion of Components of Syngas

The following stoichiometric equations represent the complete combustion of syngas fuel in the ambient air:



These equations are re-written as follows to represent the exact molar values of each component based on the highest syngas compositions in the table above:



The ambient air is composed of 20.9% O₂ and 79.1% N₂ (assuming negligible minor components).

Assuming 100 moles of syngas, the total moles of O₂ required for complete combustion is:

$$\text{Total O}_2 \text{ required} = 9 + 9 + 4 = 22 \text{ moles of O}_2$$

The corresponding moles of N₂ that will accompany 22 moles of O₂ from combustion air and will be added to the exhaust are calculated as:

$$\text{Additional N}_2 \text{ from combustion air in exhaust} = 22 \times 79.1/20.9 = 83.263 \text{ moles of N}_2$$

Next total moles of exhaust per mole of syngas combusted are calculated as follows (on dry basis with no excess air):

$$[18 (\text{CO}_2 \text{ from CO combustion}) + 2 (\text{CO}_2 \text{ from CH}_4 \text{ combustion}) + 12 (\text{CO}_2 \text{ from fuel}) + 50 (\text{N}_2 \text{ from fuel}) + 83.26 (\text{N}_2 \text{ from combustion air})]/100 = 1.6526 \text{ moles of exhaust air/mole of syngas}$$

Calculated Higher Heating Value (HHV) of Syngas based on Composition

HHV of syngas is calculated based on the proposed composition of syngas and HHV of each component (taken from reference: https://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html see last page of this Appendix for a hard copy):

HHV is calculated using the formula below and summarized in the following table:

$$\text{HHV of Syngas} = \Sigma [\text{composition of each component (\%)} \times \text{HHV of components}]$$

Syngas Component	Composition (%age by weight)	HHV of Each Component	HHV of Each Component based on Composition (Btu/dscf)
CO	18	323	58.14
H ₂	18	325	58.5
CH ₄	2	1,011	20.22
CO ₂	12	0	0
N ₂	Balance (50%)	0	0
Total (HHV of Syngas) =			137 Btu/dscf

Calculated F-Factor (dscf/MMBtu) based on Mass Balance and HHV of Syngas

F-Factor for syngas is calculated as follows:

$$\begin{aligned}\text{Syngas F-Factor (dscf/MMBtu)} &= 1.6526 \div 137 \text{ Btu/dscf} \times 10^6 \text{ Btu/MMBtu} \\ &= 12,063 \text{ dscf/MMBtu} \\ &\sim 12,100 \text{ dscf/MMBtu} \\ &\text{(rounded for conservative estimate of emissions)}\end{aligned}$$



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Fuel Gases Heating Values

Fuel gases combustion and heating values - acetylene, blast furnace gas, ethane, biogas and more - Gross and Net values

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Fuel gases gross and net heating values:

Gas	Gross Heating Value		Net Heating Value	
	(Btu/ft ³)	(Btu/lb)	(Btu/ft ³)	(Btu/lb)
Acetylene (ethyne) - C ₂ H ₂	1498	21569	1447	20837
Benzene	3741	18150	3590	17418
Blast Furnace gas	92	1178	92	1178
Blue water gas		6550		
Butane - C ₄ H ₁₀	3225	21640	2977	19976
Butylene (Butene)	3077	20780	2876	19420
Carbon to CO ₂		14150		14150
Carbon to CO		3980		3980
Carbon monoxide - CO	323	4368	323	4368
Carburetted Water Gas	550	11440	508	10568
Coal gas	149	16500		
Coke Oven Gas	574	17048	514	15266
Digester Gas (Sewage or Biogas)	690	11316	621	10184
Ethane - C ₂ H ₆	1783	22198	1630	20295
Ethyl alcohol saturated with water	1548	12804		
Ethylene	1631	21884	1530	20525
Hexane	4687	20526	4315	18976
Hydrogen (H ₂)	325	61084	275	51628
Hydrogen Sulphide	672	7479		
Landfill Gas	476			
Methane - CH ₄	1011	23811	910	21433
Methyl alcohol saturated with water	818	9603		
Naphthalene	5859	17288		
Natural Gas (typical)	950	19500	850	17500
Octane saturated with water	1150	22500	1050	22000
Pentane	6239	20542	3170	10444
Propane	3981	20908	3679	19322
Producer gas		2470		
Propane - C ₃ H ₈	2572	21564	2371	19834
Propene (Propylene) - C ₃ H ₆	2332	20990	2181	19630
Propylene	2336	21042	2185	19683
Sasol	500	14550	443	13016
Sulphur		3940		
Toluene	4408	18129	4206	17301
Water Gas (bituminous)	261	4881	239	4469
Xylene	5155	18410		

- 1 Btu/ft³ = 8.9 kcal/m³ = 3.73x10⁴ J/m³
- 1 Btu/lb = 2,326.1 J/kg = 0.55556 kcal/kg

Volumetric Heating Values are based on standard temperatures and pressure of dry gas - 60°F and 14.73 psi.

- Gases Densities

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- Acetylene - Thermophysical Properties - Chemical, Physical and Thermal Properties of Acetylene
- Biogas - Carbon Nitrogen Ratios - Carbon - Nitrogen ratios for biogas produced from various raw materials
- Biogas - Energy Content - Energy content in biogas produced from municipal and industrial waste
- Biogas - Typical Composition - Typical composition of biogas produced from household waste