April 7, 2022

Jose Garibay
E & J Gallo Winery
18000 W River Rd
Livingston, CA 95334

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: N-1237
Project Number: N-1211986

Dear Mr. Garibay:

Enclosed for your review and comment is the District's analysis of E & J Gallo Winery's application for an Authority to Construct for the modification of an existing digester served by a flare to allow the biogas generated to be sent to any equipment at the facility that is authorized to utilize biogas, and for the installation of a new 1,966 bhp IC engine that will power an electrical generator and will be fueled with natural gas and biogas from the existing anaerobic reactor, at 18000 W River Rd, Livingston.

The notice of preliminary decision for this project has been posted on the District's website (www.valleyair.org). After addressing all comments made during the 30-day public notice and 45-day EPA notice comment periods, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Jesse A. Garcia of Permit Services at (559) 230-5918.

Sincerely,

Brian Clements
Director of Permit Services

BC:jag

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email
cc: Laura Yannayon, EPA (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review

Modification of Wastewater Digester Gas Operation to Allow Combustion of Biogas in Additional Equipment and Installation of a New Natural Gas/Biogas-Fired IC Engine with SCR

Facility Name:	E & J Gallo Winery
Mailing Address:	18000 W. River Rd Livingston, CA 95334
Contact Person:	Kim Burns
Telephone:	(559) 349-3643
E-Mail:	kim.burns@ejgallo.com
Application #s:	N-1237-661-5 and '-892-0
Project #:	N-1211986
Deemed Complete:	June 24, 2021

Date:	April 7, 2022
Engineer:	Jesse A. Garcia
Lead Engineer:	Derek Fukuda

I. Proposal

The primary business of E & J Gallo Winery is the production of wine. E & J Gallo Winery has requested two Authority to Construct (ATC) permits for the following:

- Modify the equipment description for an existing wastewater digester gas operation with a 32.4 MMBtu/hr enclosed flare (see Appendix A for current Permit N-1237-661-3) to allow the biogas generated in the reactor to be sent to any equipment that is authorized to utilize biogas, rather than just the equipment that is specifically listed on the current permit, and
- Install a new 1,966 bhp lean-burn IC engine with a selective catalytic reduction (SCR) system to control emissions that will power a 1,429 kW electrical generator and will be fueled with natural gas and digester gas. The applicant has proposed to limit operation of the new IC engine to 8,400 hours per year. (See Appendix B for draft ATC permits N-1237-661-5 and -892-0).

The change proposed for the permit for the existing wastewater digester gas operation (Permit Unit N-1237-661) to allow the biogas generated to be sent to any equipment that is authorized to utilize biogas will provide greater flexibility for the usage of the biogas without the need to modify the permit to list or remove equipment. However, this change will not result in a change in the method of operation of the existing wastewater digester gas operation. Therefore, the proposed modification to permit '-661 does not constitute a New Source Review (NSR) modification and is not subject to the requirements of District Rule 2201.

E & J Gallo Winery has received their Title V Permit. This modification is a Title V significant modification pursuant to Rule 2520, and can be processed with a Certificate of Conformity (COC). Since the facility has specifically requested that this project be processed in that manner, the 45-day EPA comment period will be satisfied prior to the issuance of the Authority to Construct. E & J Gallo Winery must apply to administratively amend their Title V permit.

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (8/15/19)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (8/15/19)
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 4301	Fuel Burning Equipment (12/17/92)
Rule 4311	Flares (12/17/20)
Rule 4701	Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702	Internal Combustion Engines (8/19/21)
Rule 4801	Sulfur Compounds (12/17/92)

40 CFR Part 60, Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
40 CFR Part 63, Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
40 CFR Part 64 – Compliance Assurance Monitoring

CH&SC 41700	Risk Management Review
CH&SC 42301.6	School Notice

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

III. Project Location

The facility is located at 18000 W River Rd in Livingston, CA. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

N-1237-661 (Digester with Enclosed Flare)

Wastewater sources at the facilities include winery and grape concentrate plant process water, byproducts from brandy distillation (stillage), and grape receiving area wash water.

The grape receiving area wash water is screened to reduce solids and then pumped to the pre-acidification tank with the other wastewater streams. In the pre-acidification tank, potassium hydroxide is added to maintain a pH between 6.5 and 8.5; nutrients and alkalinity is also added as needed.

The digester consists of anaerobic digesters that are designed to accelerate and control the decomposition of organic matter by microorganisms in the absence of oxygen. Anaerobic decomposition results in the conversion of organic compounds in the material into methane (CH_4), carbon dioxide (CO_2), and water rather than intermediate Volatile Organic Compounds (VOCs). The gas generated by this process is known as biogas, waste gas, or digester gas. In addition to methane and carbon dioxide, biogas may also contain small amounts of Nitrogen (N_2), Oxygen (O_2), Hydrogen Sulfide (H_2S), and Ammonia (NH_3). Biogas may also include trace amounts of various VOCs that remain from incomplete digestion of the volatile solids in the incoming substrate. Because biogas is mostly composed of methane, the main component of natural gas, the gas produced in the digester can be cleaned to remove H_2S and other impurities and used as fuel.

A biological scrubber is used to remove hydrogen sulfide (H_2S) from the digester gas stream followed by two activated carbon units prior to incineration. The two activated carbon units are in series and operated simultaneously or one at a time when one is being serviced. The limit for the H_2S concentration influent to the engines/flare to 40 ppmv.

From the scrubber and activated carbon units, the biogas is currently sent to the enclosed emergency flare or two winery IC engines listed in permits N-1237-605 and ‘-606. With this project, the permit for the wastewater digester operation will be modified to allow the biogas to be combusted in any equipment authorized to receive biogas, including a new 1,966 bhp lean-burn IC engine being permitted under this project, rather than just the existing IC engines that are currently listed on the permit. When the existing IC engines and proposed IC engine are not operating or cannot use all of the biogas, and during process upsets and emergencies, the biogas will be combusted in the existing 32.4 MMBtu/hr enclosed flare.

The flare is permitted to operate up to 200 hours per year.

<u>N-1237-892 (Natural Gas/Digester Gas-Fired IC Engine)</u>

The applicant is proposing to install one 1,966 bhp Jenbacher Model JMC420 GS lean burn natural gas and digester gas-fired IC engine. The engine will be equipped with an SCR system and will power an electrical generator that will produce up to 1,429 kWe. Natural gas and/or digester gas, which consists mostly of methane will be used as fuel in the IC engine to produce power. The maximum sulfur content of the digester gas used to fuel the engine will be 40 ppmv as H_2S. The engine will power an electrical generator that will produce power that will be sold to a utility. Heat from the engine will be recovered for use for operations at the winery. The IC engine will be permitted to operate up to 24 hours per day and 8,400 hours per year.

V. Equipment Listing

N-1237-661 (Digester with Enclosed Flare)

Pre-Project Equipment Description:

N-1237-661-3: DIGESTER GAS OPERATION COMPOSED OF A WASTE WATER TREATMENT SYSTEM WITH AN EQUALIZATION TANK, HIGH RATE ANAEROBIC DIGESTER, TWO LOW RATE ANAEROBIC DIGESTERS, AND MEMBRANE BIOLOGICAL REACTOR SYSTEM CONSISTING OF AN ANOXIC TANK, A PRE-AERATION TANK, AND TWO MEMBRANE BIOLOGICAL REACTORS WITH BIOGAS SENT TO ONE BIOLOGICAL SCRUBBER, TWO ACTIVATED CARBON FILTERS, THE DIGESTER GAS WILL BE ROUTED TO TWO IC ENGINES (PERMITS N-1237-605 AND '606), OR TO A 600 CFM (EQUIVALENT TO 32.4 MMBTU/HR) OVIVO GWE ENCLOSED EMERGENCY FLARE

Proposed Modification:

Modify the permit for the digester gas operation to allow the biogas to be combusted in additional equipment authorized to receive biogas, rather than just the two IC engines currently listed on the permit

N-1237-661-5: MODIFICATION OF DIGESTER GAS OPERATION COMPOSED OF A WASTE WATER TREATMENT SYSTEM WITH AN EQUALIZATION TANK, HIGH RATE ANAEROBIC DIGESTER, TWO LOW RATE ANAEROBIC DIGESTERS, AND MEMBRANE BIOLOGICAL REACTOR SYSTEM CONSISTING OF AN ANOXIC TANK, A PRE-AERATION TANK, AND TWO MEMBRANE BIOLOGICAL REACTORS WITH BIOGAS SENT TO ONE BIOLOGICAL SCRUBBER, TWO ACTIVATED CARBON FILTERS, THE DIGESTER GAS WILL BE ROUTED TO TWO IC ENGINES (PERMITS N-1237-605 AND '606), OR TO A 600 CFM (EQUIVALENT TO 32.4 MMBTU/HR) OVIVO GWE ENCLOSED EMERGENCY FLARE: MODIFY PERMIT TO ALLOW BIOGAS TO BE SENT TO ANY EQUIPMENT AUTHORIZED TO RECEIVE BIOGAS

Post-Project Equipment Description:

N-1237-661-5: DIGESTER GAS OPERATION COMPOSED OF A WASTE WATER TREATMENT SYSTEM WITH AN EQUALIZATION TANK, HIGH RATE ANAEROBIC DIGESTER, TWO LOW RATE ANAEROBIC DIGESTERS, AND MEMBRANE BIOLOGICAL REACTOR SYSTEM CONSISTING OF AN ANOXIC TANK, A PRE-AERATION TANK, AND TWO MEMBRANE BIOLOGICAL REACTORS WITH BIOGAS SENT TO ONE BIOLOGICAL SCRUBBER, TWO ACTIVATED CARBON FILTERS, THE DIGESTER GAS WILL BE ROUTED TO OTHER EQUIPMENT AUTHORIZED TO RECEIVE BIOGAS OR TO A 600 CFM (EQUIVALENT TO 32.4 MMBTU/HR) OVIVO GWE ENCLOSED EMERGENCY FLARE

N-1237-892 Natural Gas/Digester Gas-Fired IC Engine

N-1237-892-0: 1,966 BHP JENBACHER MODEL JMC420 GS NATURAL GAS/DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND OXIDATION CATALYST POWERING AN ELECTRICAL GENERATOR

VI. Emission Control Technology Evaluation

N-1237-661
Digester

Inside the digester, under anaerobic conditions, biological organisms digest organic wastes in the wastewater from the wine and beverage manufacturing process. This process generates waste gas, which primarily consists of methane CH_4, H_2S, and VOCs.

A biological scrubber is used to remove H_2S from the digester gas stream followed by two activated carbon units prior to incineration in the IC engines or the enclosed emergency flare. The two activated carbon units will be installed in series and will be operated simultaneously or one at a time when one is being serviced. Due to the low concentrations of H_2S present in the digester gas, it is not practical to establish the scrubber's maximum H_2S removal efficiency. Instead, the applicant is proposing to limit the H_2S concentration influent to the engines/flare to 40 ppmv. The proposed H2S concentration limit should be achievable utilizing the biological scrubber.

Emergency Flare

The applicant is proposing to combust the digester gas in an enclosed flare during emergency situations where the engines cannot operate. The flare is a commercially available unit that is designed specifically for this application. Digester gas combustion generates NO_x, SO_x, PM_{10}, CO and VOC emissions. The emergency flare will not operate more than 200 hours/year for non-emergency purposes.

N-1237-892 (Natural Gas/Digester Gas-Fired IC Engine)

The proposed engine will be equipped with the following:

- Turbocharger
- Intercooler/aftercooler
- Air/Fuel Ratio or O_2 Controller
- Lean Burn Technology
- Oxidation Catalyst
- Selective Catalytic Reduction (SCR)

The turbocharger reduces NO_X emissions from engines by increasing the efficiency and promoting more complete burning of the fuel.

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

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.

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.

An oxidation catalyst decreases CO and VOC emissions by using a catalyst to promote the chemical oxidation of VOC and CO into H_2O and CO_2.

A Selective Catalytic Reduction (SCR) system operates as an external control device where exhaust gases and a reagent pass through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it is converted to ammonia or ammonia may be directly injected into the exhaust. The ammonia reduces NO_X over the catalyst bed forming elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces NO_X emissions by 90% or more.

In order to satisfy the BACT requirements for the proposed engine when it is primarily fueled with natural gas, the applicant is required to comply with the following limits for NO_X, CO, and VOC, which are based on the South Coast Air Quality Management District (SCAQMD) Rule 1110.2 limits for new non-emergency IC engines driving electrical generators: 0.07 lb-NO_X/MW-hr, 0.20 lb-CO/MW-hr, 0.10 lb-VOC/MW-hr. As specified in SCAQMD Rule 1110.2, engines that produce combined heat and electrical power, such as the engine that the applicant has proposed, may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of net electricity produced (MWe-hr) for purposes of determining compliance with the preceding lb-MW-hr emission limits. The applicant has proposed to comply with the required NO_X and CO emission limits when the engine is fueled primarily with natural gas and has proposed a lower VOC limit.

The applicant has proposed that when the engine is fueled primarily with digester gas that it will comply with the same exhaust concentration limits (ppmv) for NO_X, CO, and VOC as required when it is fueled primarily with natural gas.

The proposed IC engine will be fueled with PUC-quality natural gas or digester gas. The digester gas will be scrubbed to remove sulfur prior to combustion in the engine. Reducing the H_2S content of the biogas prior to combustion will minimize SOx and PM_{10} emissions from the use of biogas as in the engine. The digester gas used to fuel the IC engine will be limited by permit condition to a maximum sulfur content of no more than 40 ppmv sulfur as H_2S.

VII. General Calculations

As discussed above, the proposed modification of the permit for the existing digester gas operation (Permit Unit N-1237-661) to allow the biogas generated in the digester to be sent to any equipment that is authorized to utilize biogas will not result in a change in the method of operation of the existing wastewater digester. Therefore, the proposed change to the permit does not constitute an NSR modification and is not subject to the requirement of District Rule 2201. However, emission calculations will be performed for Permit Unit N-1237-661 for reference purposes only.

A. Assumptions

- As discussed below, the stationary source where the project is located is an existing major source for NO_X, CO, and VOC

<u>Assumptions for N-1237-661 (Digester with Enclosed Flare)</u>

<u>Assumptions for Digester Gas</u>

- Biogas higher heating value = 749 Btu/scf (per gas analysis, see Appendix C)
- The digester gas operation is a closed system with the only source of emissions being from the flare

<u>Assumptions for Flare</u>

- Maximum daily operating schedule = 24 hr/day (worst case)
- Maximum annual operating schedule = 200 hr/year (current permit)
- The maximum sulfur content of the digester gas combusted in the flare = 40 ppmv as H_2S (current permit)
- The flare is used to control VOC, H_2S, and CH_4 in the gas that is generated by the digester and is therefore an emissions control device

<u>Assumptions for N-1237-892 (Natural Gas/Digester Gas-Fired IC Engine)</u>

- The proposed 1,966 bhp IC engine will power a 1,429 kW electrical generator and will be permitted to operate up to 24 hours per day and 8,400 hours per year (proposed by applicant)

- The proposed 1,966 bhp IC engine will be fueled with PUC-quality natural gas, digester gas, or a blend of natural gas and digester gas (proposed by applicant)

- The typical higher heating value of natural gas is 1,000 Btu/scf (District Practice/District Policy APR 1720 - Generally Accepted SO_X Emission Factor for Combustion of PUC-quality Natural Gas)

- F Factor (ratio of combustion exhaust volume to higher heating value of fuel) for natural gas, corrected to 60°F (15.6°C) (District standard temperature): 8,578 dscf/MMBtu (corrected from natural gas F-Factor of 8,710 dscf/MMBtu at 20 °C (68 °F) given in 40 CFR 60, Appendix B)

- F Factor for the digester gas: 8,784 dscf/MMBtu (dry, adjusted to 60 °F) (corrected from F-Factor of 8,920 dscf/MMBtu at 68 °F based on the February 21, 2018 analysis of the digester gas composition; See Appendix C for a copy of the digester gas analysis)

- Net mechanical efficiency of the IC engine based on the HHV of the fuel is assumed to be 36% based on the net lower heating value (LHV) electrical efficiency provided by the engine supplier and adjusting the net LHV efficiency by the ratio of the LHV to HHV of methane (0.90), the primary compound that provides heat energy in natural gas and digester gas, and adjusting for the estimated efficiency of the electrical generator (= (1,429 kW x 3,412.14 Btu/kW-hr)/(1,966 bhp x 2,545 Btu/bhp-hr)) (See Appendix D for engine data sheet)

- The applicant indicates that 5.4 MMBtu/hr of useful heat will be recovered from the proposed IC engine for use in processes at the winery. This value does not exceed the amount of useful heat that the engine data sheet indicates can be recovered from the proposed engine

- In order to satisfy the BACT requirements for NO_X, CO, and VOC emissions from the engine when it is primarily fueled with natural gas, the applicant is required to comply with the following limits: 0.07 lb-NO_X/MW-hr, 0.20 lb-CO/MW-hr, and 0.1 lb-VOC/MW-hr. These limits are based on the SCAQMD Rule 1110.2 limits for new non-emergency IC engines driving electrical generators. As specified in SCAQMD Rule 1110.2, engines that produce combined heat and electrical power may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of net electricity produced (MWe-hr) for purposes of determining compliance with lb-MW-hr NO_X, CO, and VOC emission limits

- Taking into account the 5.4 MMBtu/hr (1.588 MW_{th}) credit for heat recovery, the engine must comply with the following NO_X, CO, and VOC emissions limits to satisfy BACT when the engine is fueled primarily with natural gas: 0.049 g-NO_X/bhp-hr (0.07 lb-NO_X/MW-hr x 3.017 MW/1,966 bhp x 453.59 g/lb), 0.14 g-CO/bhp-hr (0.20 lb-CO/MW-hr x 3.017 MW/1,966 bhp x 453.59 g/lb), and 0.07 g-VOC/bhp-hr (0.1 lb-VOC/MW-hr x 3.017 MW/1,966 bhp x 453.59 g/lb). The applicant has proposed to comply with the required NO_X and CO emission limits and proposed a lower VOC emission limit of 12 ppmv @ 15% O_2 (0.050 g-VOC/bhp-hr)

- The applicant has proposed that when the IC engine is fueled primarily with digester gas, it will continue to comply with the same NO_X, CO, and VOC exhaust emission concentration (ppmv) limits that are required when the engine is fueled primarily with natural gas

- The maximum sulfur content of the scrubbed digester gas used to fuel the engine: 40 ppmv as H_2S (approximately 2.4 grains/100 scf; proposed by applicant and required as BACT for SO_X and PM_{10} from the IC engine)

- bhp to Btu/hr conversion: 2,545 Btu/bhp-hr
- kW-hr to Btu conversion: 3,412.14 Btu/kW-hr

Assumptions for Commissioning Period for the Engine

- The ATC permit for the digester gas-fired IC engine will include a commissioning period without the operation of the SCR system to allow testing, adjustment, and tuning of the engine, and calibration and optimization of the SCR system. The duration of the commissioning period shall consist of no more than 50 hours of operation of the engine without injection of urea for operation of the SCR system
- NO_X emissions from the engine during the commissioning period will be calculated as uncontrolled based on information provided by the engine supplier
- The applicant indicates that the oxidation catalyst will be in place and operate during commissioning of the engine; therefore, the CO and VOC emission factors for the engine during commissioning will be the same as during normal operation

General Assumptions

- lb-Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Molecular weights:
  NO_X (as NO_2) = 46 lb/lb-mol CO = 28 lb/lb-mol NH3 = 17 lb/lb-mol
  VOC (as CH_4) = 16 lb/lb-mol SO_X (as SO_2) = 64 lb/lb-mol H_2S= 34 lb/lb-mol
- $PM_{2.5}$ emissions from the digester gas-flare and natural gas/digester gas-fired engine are assumed to be equal to PM_{10} emissions.

B. Emission Factors

Emission Factors for N-1237-661 (Digester with Enclosed Flare)

Emission Factors for Combustion of Digester Gas in the Flare

The emission factors for NO_X (0.06 lb/MMBtu), PM_{10} (0.008 lb/MMBtu), CO (0.75 lb/MMBtu), and VOC (0.019 lb/MMBtu) from the flare are taken from the current permit. The NO_X and PM_{10} emission factors were provided by the flare manufacturer when the facility proposed to install the flare. The NO_X, CO, and VOC emission factors have been confirmed by source testing of emissions from the flare (8/25/2015). The SO_X emission factor (0.0075 lb/MMBtu) is based on the maximum sulfur content of the digester gas in the current permit (40 ppmv as H_2S).

Emission Factors For Combustion of Digester Gas in the Flare		
Pollutant	**lb/MMBtu**	**Source**
NO_X	0.06	Current Permit/Flare Manufacturer
SO_X	0.009	40 ppmvd in flared gas (Current Permit – See Equation Below)
PM_{10}	0.008	Current Permit/Flare Manufacturer
CO	0.75	Current Permit
VOC	0.019	Current Permit

<u>SO_X – 40 ppmvd H_2S in fuel gas</u>

$$\frac{40\ \mathrm{ft^3\ H_2S}}{10^6\ \mathrm{ft^3}} \times \frac{32\ \mathrm{lb-S}}{\mathrm{lb-mol\ H_2S}} \times \frac{\mathrm{lb-mol}}{379.5\ \mathrm{ft^3}} \times \frac{64\ \mathrm{lb-SO_2}}{32\ \mathrm{lb-S}} \times \frac{1\ \mathrm{ft^3}}{749\ \mathrm{Btu}} \times \frac{10^6\ \mathrm{Btu}}{\mathrm{MMBtu}} = 0.009\ \frac{\mathrm{lb-SO_X}}{\mathrm{MMBtu}}$$

Emissions Factors for N-1237-892 (Natural Gas/Digester Gas-Fired IC Engine)

Emission Factors for the Engine during the Commissioning Period

The commissioning period precedes normal operation of an engine. Activities conducted during the commissioning period typically include the following: 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 damage to this equipment. 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.[1] 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.

The applicant has indicated that during the commissioning period the SCR system will not be operated, but the oxidation catalyst will be in place and operate during commissioning of the engine. Therefore, NO_X will be the only pollutant with an increased emission factor during the commissioning period.

The emission factor for NO_X from the engine during the commissioning period without operation of the SCR system (0.6 g/bhp-hr) was provided by the engine supplier. The emission factors during the commissioning period for SO_X (0.0091 g/bhp-hr for natural gas fuel and 0.03 g/bhp-

[1] 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 (https://www.epa.gov/sites/production/files/2014-03/documents/4_2_2013_qa_stationary_rice_neshap_nsps_stationaryci_si_ice.pdf)

hr for digester gas fuel), PM_{10} (0.032 g/bhp-hr for natural gas fuel and 0.05 g/bhp-hr for digester gas fuel), CO (0.14 g/bhp-hr), and VOC (0.049 g/bhp-hr for natural gas fuel and 0.050 g/bhp-hr for digester gas fuel) are assumed to be the same emission factors as during normal operation. The SO_X emission factors are based on the maximum sulfur content of the fuel (1.0 grains/100 scf for natural gas pursuant to District policy; and 40 ppmv as H_2S, approximately 2.4 grains/100 scf, for digester gas as required by BACT). The PM_{10} emission factor for the engine when it is fueled with natural gas is from AP-42, Section 3.2 Natural Gas-fired Reciprocating Engines (July 2000). The PM_{10} emission factor for the engine when it is fueled with digester gas is based on the value given for landfill gas-fired engines in AP-42, Draft Section 2.4 Municipal Solid Waste Landfills (October 2008). The NH_3 emission factors for the engine (0.044 g/bhp-hr for natural gas fuel and 0.045 g/bhp-hr for digester gas fuel) are based a maximum concentration of 10 ppmv NH_3 @ 15% O_2 in the engine exhaust.

Commissioning Period Emission Factors for IC Engine			
Pollutant	Natural Gas Fuel	Digester Gas Fuel	Source
	g/bhp·hr		
NO_X	0.6		Uncontrolled EF from Engine Supplier
SO_X	0.0091	0.03	1 gr-sulfur/100 scf in natural gas pursuant to District Policy APR 1720 (12/20/2001) and 40 ppmvd sulfur in digester gas; Mass Balance equation below
PM_{10}	0.032	0.05	AP-42, Table 3.2.2 (July 2000) for Natural Gas Fuel and AP-42, Draft Table 2.4.4 (October 2008) (value for digester gas based on landfill gas fueled engines)
CO	0.14	0.14	Proposed by Applicant
VOC	0.049	0.050	Applicant Proposal & Catalyst Supplier's Guarantee

<u>Emission Factors for Natural Gas Fuel after the Commissioning Period:</u>

Emission Factors for IC Engine After Commissioning when Fueled with Natural Gas				
Pollutant	g/bhp·hr	lb/MMBtu	ppmvd (@ 15%O_2)	Source
NO_X	0.049	0.0153	4.1 ppmvd	BACT Requirement/Proposed by Applicant –See equation below
SO_X	0.0091	0.00285	--	District Policy APR 1720 (12/20/2001) - See mass balance equation below
PM_{10}	0.032	0.0099871	--	AP-42, Table 3.2.2 (July 2000) See equation below
CO	0.14	0.0437	19.5 ppmvd	BACT Requirement/Proposed by Applicant See equation below
VOC	0.049	0.0154	12.0 ppmvd as CH_4	Proposed by Applicant & Catalyst Supplier's Guarantee – See equation below
NH_3	0.044	0.0136	10 ppmvd	10 ppmvd @ 15% O_2 in exhaust; Required/ Proposed – See equation below

NO_X – 0.049 g/bhp-hr

$$0.049\ \frac{\text{g NO}_X}{\text{bhp}-\text{hr}} \times \frac{1\ \text{lb}}{453.59\ \text{g}} \times \frac{1\ \text{bhp}-\text{hr}}{2{,}545\ \text{Btu}} \times \frac{0.36\ \text{Btu}_{\text{out}}}{1\ \text{Btu}_{\text{in}}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} = 0.0153\ \frac{\text{lb}-\text{NO}_X}{\text{MMBtu}}$$

$$0.0153\ \frac{\text{lb NO}_X}{\text{MMBtu}} \times \frac{(20.9-15)\%\ \text{O}_2}{20.9\%\ \text{O}_2} \times \frac{1\ \text{MMBtu}}{8{,}578\ \text{ft}^3} \times \frac{379.5\ \text{ft}^3}{\text{lb}-\text{mole}} \times \frac{\text{lb}-\text{mole}}{46\ \text{lb NO}_X} \times \frac{10^6\ \text{ppmv}}{1} = 4.1\ \text{ppmv NO}_X\ @\ 15\%\ \text{O}_2$$

SO_X – 0.00285 lb SOx/MMBtu (based on 1 gr-S/100 scf)

$$0.00285\ \frac{\text{lb SO}_X}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp}-\text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.0091\ \frac{\text{g}-\text{SO}_X}{\text{bhp}-\text{hr}}$$

PM_{10} – 0.0099871 lb/MMBtu

$$0.0099871\ \frac{\text{lb PM}_{10}}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp}-\text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.032\ \frac{\text{g}-\text{PM}_{10}}{\text{bhp}-\text{hr}}$$

CO – 0.14 g/bhp-hr

$$0.14\ \frac{\text{g CO}}{\text{bhp}-\text{hr}} \times \frac{1\ \text{lb}}{453.59\ \text{g}} \times \frac{1\ \text{bhp}-\text{hr}}{2{,}545\ \text{Btu}} \times \frac{0.36\ \text{Btu}_{\text{out}}}{1\ \text{Btu}_{\text{in}}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} = 0.0437\ \frac{\text{lb}-\text{CO}}{\text{MMBtu}}$$

$$0.0437\ \frac{\text{lb CO}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ \text{O}_2}{20.9\%\ \text{O}_2} \times \frac{1\ \text{MMBtu}}{8{,}578\ \text{ft}^3} \times \frac{379.5\ \text{ft}^3}{\text{lb}-\text{mole}} \times \frac{\text{lb}-\text{mole}}{28\ \text{lb CO}} \times \frac{10^6\ \text{ppmv}}{1} = 19.5\ \text{ppmv CO}\ @\ 15\%\ \text{O}_2$$

VOC (as CH_4) – 12 ppmvd @ 15% O_2 in exhaust

$$\frac{12\ \text{ppmv VOC}\ @\ 15\%\ \text{O}_2}{10^6} \times \frac{16\ \text{lb}-\text{VOC}}{\text{lb}-\text{mole}} \times \frac{\text{lb}-\text{mole}}{379.5\ \text{ft}^3} \times \frac{8{,}578\ \text{ft}^3}{1\ \text{MMBtu}} \times \frac{20.9\%\ \text{O}_2}{(20.9-15)\%\ \text{O}_2} = 0.0154\ \frac{\text{lb}-\ \text{VOC}}{\text{MMBtu}}$$

$$0.0154\ \frac{\text{lb VOC}}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp}-\text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.049\ \frac{\text{g VOC}}{\text{bhp}-\text{hr}}$$

NH_3 – 10 ppmvd @ 15% O_2 in exhaust

$$\frac{10\ \text{ppmv NH}_3\ @\ 15\%\ \text{O}_2}{10^6} \times \frac{17\ \text{lb NH}_3}{\text{lb}-\text{mole}} \times \frac{\text{lb}-\text{mole}}{379.5\ \text{ft}^3} \times \frac{8{,}578\ \text{ft}^3}{1\ \text{MMBtu}} \times \frac{20.9\%\ \text{O}_2}{(20.9-15)\%\ \text{O}_2} = 0.0136\ \frac{\text{lb}-\text{NH}_3}{\text{MMBtu}}$$

$$0.0136\ \frac{\text{lb NH}_3}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp}-\text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.044\ \frac{\text{g}-\ \text{NH}_3}{\text{bhp}-\text{hr}}$$

Emission Factors for Digester Gas Fuel after the Commissioning Period:

Emission Factors for IC Engine After Commissioning when Fueled with Digester Gas				
Pollutant	g/bhp·hr	lb/MMBtu	ppmvd (@ 15%O_2)	Source
NO_X	0.050	0.0155	4.1 ppmvd	Proposed by Applicant –See equation below
SO_X	0.03	0.0090	40 ppmvd as H_2S, in fuel gas	BACT Requirement/ Mass balance equation below
PM_{10}	0.05	0.015	--	AP-42 Draft Table 2.4.4 (October 2008) (Value for Landfill Gas Engines) – See equation below
CO	0.14	0.0448	19.5 ppmvd	Proposed by Applicant See equation below
VOC	0.050	0.0157	12.0 ppmvd as CH_4	Proposed by Applicant & Catalyst Supplier's Guarantee – See equation below
NH_3	0.045	0.0139	10 ppmvd	10 ppmvd @ 15% O_2 in exhaust; Required/ Proposed – See equation below

NO_X – 4.1 ppmvd @ 15% O_2 in exhaust

$$\frac{4.1\ \text{ppmv NO}_X\ @\ 15\%\ \text{O}_2}{10^6} \times \frac{46\ \text{lb NO}_X}{\text{lb} - \text{mole}} \times \frac{\text{lb} - \text{mole}}{379.5\ \text{ft}^3} \times \frac{8{,}784\ \text{ft}^3}{1\ \text{MMBtu}} \times \frac{20.9\%\ \text{O}_2}{(20.9 - 15)\%\ \text{O}_2} = 0.0155\ \frac{\text{lb} - \text{NO}_X}{\text{MMBtu}}$$

$$0.0155\ \frac{\text{lb NO}_X}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp} - \text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.050\ \frac{\text{g} -\ \text{NO}_X}{\text{bhp} - \text{hr}}$$

SO_X – 40 ppmvd H_2S in fuel gas

$$\frac{40\ \text{ft}^3\ \text{H}_2\text{S}}{10^6\ \text{ft}^3} \times \frac{32\ \text{lb} - \text{S}}{\text{lb} - \text{mol H}_2\text{S}} \times \frac{\text{lb} - \text{mol}}{379.5\ \text{ft}^3} \times \frac{64\ \text{lb} - \text{SO}_2}{32\ \text{lb} - \text{S}} \times \frac{1\ \text{ft}^3}{749\ \text{Btu}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} = 0.0090\ \frac{\text{lb} - \text{SO}_X}{\text{MMBtu}}$$

$$0.0090\ \frac{\text{lb SO}_X}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp} - \text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.03\ \frac{\text{g} - \text{SO}_X}{\text{bhp} - \text{hr}}$$

PM_{10} – 0.015 lb/MMBtu (based on 15 lb-PM/10^6 dscf CH_4)

$$0.015\ \frac{\text{lb PM}_{10}}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp} - \text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.05\ \frac{\text{g} - \text{PM}_{10}}{\text{bhp} - \text{hr}}$$

CO – 19.5 ppmvd @ 15% O_2 in exhaust

$$\frac{19.5\ \text{ppmv CO}\ @\ 15\%\ \text{O}_2}{10^6} \times \frac{28\ \text{lb CO}}{\text{lb} - \text{mole}} \times \frac{\text{lb} - \text{mole}}{379.5\ \text{ft}^3} \times \frac{8{,}784\ \text{ft}^3}{1\ \text{MMBtu}} \times \frac{20.9\%\ \text{O}_2}{(20.9 - 15)\%\ \text{O}_2} = 0.0448\ \frac{\text{lb} - \text{CO}}{\text{MMBtu}}$$

$$0.0448\ \frac{\text{lb CO}}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp}-\text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.14\ \frac{\text{g}-\text{CO}}{\text{bhp}-\text{hr}}$$

<u>VOC (as CH_4) – 12 ppmvd @ 15% O_2 in exhaust</u>

$$\frac{12\ \text{ppmv VOC @ 15\% O}_2}{10^6} \times \frac{16\ \text{lb}-\text{VOC}}{\text{lb}-\text{mole}} \times \frac{\text{lb}-\text{mole}}{379.5\ \text{ft}^3} \times \frac{8{,}784\ \text{ft}^3}{1\ \text{MMBtu}} \times \frac{20.9\%\ \text{O}_2}{(20.9-15)\%\ \text{O}_2} = 0.0157\ \frac{\text{lb}-\text{VOC}}{\text{MMBtu}}$$

$$0.0157\ \frac{\text{lb VOC}}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp}-\text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.050\ \frac{\text{g}-\text{VOC}}{\text{bhp}-\text{hr}}$$

<u>NH_3 – 10 ppmvd @ 15% O_2 in exhaust</u>

$$\frac{10\ \text{ppmv NH}_3\ \text{@ 15\% O}_2}{10^6} \times \frac{17\ \text{lb NH}_3}{\text{lb}-\text{mole}} \times \frac{\text{lb}-\text{mole}}{379.5\ \text{ft}^3} \times \frac{8{,}784\ \text{ft}^3}{1\ \text{MMBtu}} \times \frac{20.9\%\ \text{O}_2}{(20.9-15)\%\ \text{O}_2} = 0.0139\ \frac{\text{lb NH}_3}{\text{MMBtu}}$$

$$0.0139\ \frac{\text{lb NH}_3}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.36\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp}-\text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.045\ \frac{\text{g NH}_3}{\text{bhp}-\text{hr}}$$

The IC engine will be permitted to be fueled with natural gas or digester gas with no limit on the type of fuel used. Therefore, the emission factors used to calculate potential emissions from the IC engine will be based on the emission factors shown above for the IC engine when fueled with digester gas since these emission factors are equal to or greater than the emission factors when fueled with natural gas for all pollutants.

C. Calculations

1. Pre-Project Potential to Emit (PE1)

<u>PE1 for N-1237-661 (Digester with Enclosed Flare)</u>

As discussed above, the proposed change to the permit for the existing wastewater digester does not constitute an NSR modification and is not subject to the requirements of District Rule 2201. The emission calculations for Permit Unit N-1237-661 will be performed for reference purposes only.

The PE1 for the flare is calculated in the tables below using the following equations:

Daily PE = EF (lb/MMBtu) × Heat Input (MMBtu/hr) × Op. Sched. (hr/day)
Annual PE = EF (lb/MMBtu) × Heat Input (MMBtu/hr) × Op. Sched. (hr/year)

Daily PE1 for Digester Flare							
Pollutant	Emission Factor (lb/MMBtu)	x	Hourly Heat Input of Gas Flared (MMBtu/hr)	x	Daily Hours of Operation (hr/day)	=	PE1 (lb/day)
NO_X	0.06	x	32.4	x	24	=	**46.7**
SO_X	0.009	x	32.4	x	24	=	**7.0**
PM_{10}	0.008	x	32.4	x	24	=	**6.2**
CO	0.75	x	32.4	x	24	=	**583.2**
VOC	0.019	x	32.4	x	24	=	**14.8**

Annual PE1 for Digester Flare							
Pollutant	Emission Factor (lb/MMBtu)	x	Hourly Heat Input of Gas Flared (MMBtu/hr)	x	Annual Hours of Operation (hr/year)	=	PE1 (lb/year)
NO_X	0.06	x	32.4	x	200	=	**389**
SO_X	0.009	x	32.4	x	200	=	**58**
PM_{10}	0.008	x	32.4	x	200	=	**52**
CO	0.75	x	32.4	x	200	=	**4,860**
VOC	0.019	x	32.4	x	200	=	**123**

<u>PE1 for N-1237-892-0 (Natural Gas/Digester Gas-Fired IC Engine)</u>

Because the proposed natural gas/digester gas-fired IC engine is new emission units PE1 = 0 for all pollutants from this unit.

2. Post-Project Potential to Emit (PE2)

<u>PE2 for N-1237-661 (Digester with Enclosed Flare)</u>

PE2 is the same as the PE1 calculated for the unit above and summarized in the table below.

Total PE2 for N-1237-661		
Pollutant	**Daily PE2 (lb/day)**	**Annual PE2 (lb/year)**
NO_X	46.7	389
SO_X	5.8	68
PM_{10}	6.2	52
CO	233.3	1,944
VOC	1.6	13

PE2 for N-1237-892 (Natural Gas/Digester Gas-Fired IC Engine)

Daily PE2 for the IC Engine during the Commissioning Period

During commissioning, the SCR system will be adjusted and may not be operating. However, the applicant has indicated that the oxidation catalyst system will be installed and operational; therefore, only the NO_X emissions will be uncontrolled.

Daily PE2 during the commissioning period for the proposed IC engine is calculated in the tables below.

Daily PE2 during Commissioning with Natural Gas Fuel

Daily PE2 for N-1237-892 During Commissioning Period – Natural Gas Fuel								
NO_X	0.6	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**62.4**	(lb/day)
SO_X	0.0091	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**0.9**	(lb/day)
PM_{10}	0.032	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.3**	(lb/day)
CO	0.14	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**14.6**	(lb/day)
VOC	0.049	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.1**	(lb/day)

Daily PE2 during Commissioning with Digester Gas Fuel

Daily PE2 for N-1237-892 During the Commissioning Period – Digester Gas Fuel								
NO_X	0.6	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**62.4**	(lb/day)
SO_X	0.03	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.05	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.2**	(lb/day)
CO	0.14	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**14.6**	(lb/day)
VOC	0.050	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.2**	(lb/day)

Daily PE2 for the IC Engine during Normal Operation after the Commissioning Period

Daily PE for the proposed IC engine during normal operation after completion of the commissioning period is calculated in the tables below.

Daily PE2 for Operation without Commissioning with Natural Gas Fuel

Daily PE2 for N-1237-892 After Commissioning – Natural Gas Fuel								
NO_X	0.049	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.1**	(lb/day)
SO_X	0.0091	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**0.9**	(lb/day)
PM_{10}	0.032	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.3**	(lb/day)
CO	0.14	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**14.6**	(lb/day)
VOC	0.049	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.1**	(lb/day)
NH_3	0.044	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**4.6**	(lb/day)

Daily PE2 for Operation without Commissioning with Digester Gas Fuel

Daily PE2 for N-1237-892 After Commissioning – Digester Gas Fuel								
NO_X	0.050	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.2**	(lb/day)
SO_X	0.03	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.05	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.2**	(lb/day)
CO	0.14	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**14.6**	(lb/day)
VOC	0.050	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.2**	(lb/day)
NH_3	0.045	(g/bhp·hr) x	1,966	(bhp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**4.7**	(lb/day)

Annual PE2 for the IC Engine During the first Year Including Commissioning

As discussed in the assumptions section above, the proposed engine will be allowed to operate a total of 8,400 hours per year and up to 50 hours for commissioning during the first year of operation, during which the SCR system will be adjusted and may not be operating. The maximum annual PE for NO_X from the IC engine during the first year of operation that includes the commissioning period will be calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

The annual PE2 for SO_X, PM_{10}, CO, and VOC from the IC engine during the first year of operation that includes the commissioning period will be the same as the annual PE during the following years of normal operation without the commissioning period and is calculated in the table below. The annual PE for NH_3 will be conservatively calculated assuming operation of the SCR system for 8,400 hours per year.

Maximum Annual PE for NO_X Including Commissioning

1,966 bhp x (0.6 g-NO_X/bhp-hr x 50 hr + 0.050 g-NO_X/bhp-hr x 8,350 hr) ÷ 453.59 g/lb = **1,940 lb-NO_X** in first year

Annual PE2 for the IC Engine After the First Year with no Commissioning

The annual PE2 for the IC engine after completion of the first year of operation when there will not be any commissioning emissions in the table below. The maximum annual PE2 for the IC engine is calculated using the emission factors for digester gas fuel since these are higher than the emission factors for natural gas fuel.

Annual PE2 for N-1237-892 with no Commissioning								
NO_X	0.050	(g/bhp·hr) x	1,966	(bhp) x	8,400	(hr/yr) ÷ 453.59 (g/lb) =	**1,820**	(lb/yr)
SO_X	0.03	(g/bhp·hr) x	1,966	(bhp) x	8,400	(hr/yr) ÷ 453.59 (g/lb) =	**1,092**	(lb/yr)
PM_{10}	0.05	(g/bhp·hr) x	1,966	(bhp) x	8,400	(hr/yr) ÷ 453.59 (g/lb) =	**1,820**	(lb/yr)
CO	0.14	(g/bhp·hr) x	1,966	(bhp) x	8,400	(hr/yr) ÷ 453.59 (g/lb) =	**5,097**	(lb/yr)
VOC	0.050	(g/bhp·hr) x	1,966	(bhp) x	8,400	(hr/yr) ÷ 453.59 (g/lb) =	**1,820**	(lb/yr)
NH_3	0.045	(g/bhp·hr) x	1,966	(bhp) x	8,400	(hr/yr) ÷ 453.59 (g/lb) =	**1,638**	(lb/yr)

Maximum Daily and Annual PE2 for N-1237-892:

As discussed above, the maximum PE2 from the natural gas/digester gas-fired IC engine will be calculated using the higher emission factors for digester gas.

The maximum daily and annual potential emissions for each pollutant calculated above, including commissioning emissions, are shown in the table below.

Post-Project Potential to Emit (PE2) for N-1237-892			
Pollutant	**Emission Factor (g/bhp-hr)**	**Daily PE (lb/day)**	**Annual PE (lb/yr)**
NO_X (Including Commissioning)	0.6 g/bhp-hr for up to 50 hrs during commissioning, then 0.050 g/bhp-hr	62.4	1,940
NO_X (Normal Operation)	0.050	5.2	1,820
SO_X	0.03	3.1	1,092
PM_{10}	0.05	5.2	1,820
CO	0.14	14.6	5,097
VOC	0.050	5.2	1,820
NH_3	0.045	4.7	1,638

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.

Based on information provided by the applicant and in the facility files, the VOC emissions from this Stationary Source already exceed the Offset and Major Source Thresholds. Therefore, SSPE1 calculations for VOC emissions are not necessary and will not be performed as a part of this project and any permit units that only have VOC emissions will not be included.

The SSPE1 is calculated in Appendix L and presented in the following table:

SSPE1 (lb/year)					
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**
N-1237-1-3	0	0	786	0	>20,000
N-1237-4-14	12,976	3,745	6,570	194,472	
N-1237-5-3	0	0	786	0	
N-1237-6-4	0	0	82	0	
N-1237-7-3	0	0	0	0	

SSPE1 (lb/year)					
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**
N-1237-8-3	0	0	0	0	
N-1237-9-3	0	0	0	0	
N-1237-10-3	0	0	0	0	
N-1237-12-4	3,734	431	146	2,154	
N-1237-17-3	0	0	657	0	
N-1237-480-5	0	0	14	0	
N-1237-596-4	0	0	120	0	
N-1237-601-2	0	0	7	0	
N-1237-603-4	0	0	115	0	
N-1237-605-2	3,869	645	851	20,637	
N-1237-606-2	3,869	645	851	20,637	
N-1237-607-3	5,256	2,247	5,992	116,683	
N-1237-661-3	389	58	52	4,860	
N-1237-694-1	0	0	165	0	
N-1237-695-1	0	0	66	0	
N-1237-696-1	0	0	36	0	
N-1237-762-3	0	0	120	0	
N-1237-763-2	0	0	32	0	
N-1237-781-2	0	0	15	0	
N-1237-782-2	0	0	15	0	
N-1237-786-0	0	0	15	0	
N-1237-787-0	28	0	1	25	
$SSPE1_{Permit\ Unit}$	30,121	7,771	17,494	359,468	> 20,000
ERC N-2-3	0	0	0	407,020	0
SSPE1	**30,121**	**7,771**	**17,494**	**725,214**	**> 20,000**

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.

Because the VOC emissions from this Stationary Source already exceed the Offset and Major Source Thresholds, SSPE2 calculations for VOC emissions are not necessary and will not be performed as a part of this project.

SSPE2 (lb/year)					
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**
N-1237-1-3	0	0	786	0	>20,000
N-1237-4-14	12,976	3,745	6,570	194,472	
N-1237-5-3	0	0	786	0	
N-1237-6-4	0	0	82	0	
N-1237-7-3	0	0	0	0	
N-1237-8-3	0	0	0	0	
N-1237-9-3	0	0	0	0	
N-1237-10-3	0	0	0	0	
N-1237-12-4	3,734	431	146	2,154	
N-1237-17-3	0	0	657	0	
N-1237-480-5	0	0	14	0	
N-1237-596-4	0	0	120	0	
N-1237-601-2	0	0	7	0	
N-1237-603-4	0	0	115	0	
N-1237-605-2	3,869	645	851	20,637	
N-1237-606-2	3,869	645	851	20,637	
N-1237-607-1	5,256	2,247	5,992	116,683	
ATC N-1237-661-5	389	58	52	4,860	
N-1237-694-1	0	0	165	0	
N-1237-695-1	0	0	66	0	
N-1237-696-1	0	0	36	0	
N-1237-762-3	0	0	120	0	
N-1237-763-2	0	0	32	0	
N-1237-781-2	0	0	15	0	
N-1237-782-2	0	0	15	0	
N-1237-786-0	0	0	15	0	
N-1237-787-0	28	0	1	25	
ATC N-1237-892-0[2]	1,940	1,092	1,820	5,097	
$SSPE2_{Permit Unit}$	32,061	8,863	19,314	364,565	> 20,000
ERC N-2-3	0	0	0	407,020	0
SSPE2	**32,061**	**8,863**	**19,314**	**771,585**	**> 20,000**

[2] The SSPE2 values listed in this table include the worst-case annual potential to emit for NO_X during the 50 hours of allowed commissioning time where the engine is allowed to operate with uncontrolled NO_X emissions for setup and tuning of the SCR system. After the first year, the PE for NO_X emissions will be less as the engine will no longer be allowed to operate without operation of the SCR system.

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), pursuant to the Clean Air Act, Title 3, Section 302, US Codes 7602(j) and (z)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 70.2

The stationary source is not among the specific source categories specified in 40 CFR 70.2; therefore, fugitive emissions are not included when determining if it is a Major Source.

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1 (excluding facility ERCs)	30,121	7,771	17,494	17,494	359,468	> 20,000
SSPE2 (excluding facility ERCs)	32,061	8,863	19,314	19,314	364,565	> 20,000
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	Yes	No	No	No	Yes	Yes

Note: PM2.5 assumed to be equal to PM10

As seen in the table above, the facility is an existing Major Source for NOx, CO, and VOC emissions and will remain a Major Source for CO and VOC after completion 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 tons per year (tpy) for any regulated NSR pollutant and fugitive emissions are not considered when determining if the operation is a PSD Major Source.

PSD Major Source Determination (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Estimated Facility PE before Project Increase	15.1	> 250*	3.9	179.7	8.7	8.7
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source?	No	Yes	No	Yes	No	No

* As demonstrated in recent project N-1173410 (finalized February 12, 2018), this facility has a VOC PE of greater than 250 tons/year.

As shown above, the facility is an existing PSD major source for at least one pollutant.

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.

ATC N-1237-661-5 (Digester with Enclosed Flare)

As discussed above, the proposed modification of the permit for the existing digester gas operation (Permit Unit N-1237-661) to allow the biogas generated in the digester to be sent to any equipment that is authorized to utilize biogas will not result in a change in the method of operation of the existing wastewater digester. Therefore, BE calculations are not required for Permit Unit N-1237-661-5.

ATC N-1237-892-0 (Natural Gas/Digester Gas-Fired IC Engine)

Since the proposed natural gas/digester gas-fired IC engine is a new emissions unit, BE = PE1 = 0 for all pollutants from the unit.

7. SB 288 Major Modification

40 CFR Part 51.165 defines a SB 288 Major Modification 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.

An SB 288 Major Modification for a given pollutant can only occur at a stationary source that is a major source for that specific pollutant. The only pollutants for which this facility is a major source are NO_X, CO, and, VOC; therefore, this project is not an SB 288 Major Modification for any other pollutant. In addition, Rule 2201 does not include an SB 288 Major Modification threshold for CO emissions; therefore, the project is not an SB 288 Major Modification for CO.[3]

Since this facility is a major source for NO_X and VOC, the project's PE2 is compared to the SB 288 Major Modification Thresholds in the following table in order to determine if further SB 288 Major Modification calculation is required.

As calculated in the Calculation section above:

SB 288 Major Modification Thresholds			
Pollutant	**Project PE2 (lb/year)**	**Threshold (lb/year)**	**SB 288 Major Modification Calculation Required?**
NO_x	1,940	50,000	No
VOC	1,820	50,000	No

Since none of the SB 288 Major Modification Thresholds are surpassed with this project, this project does not constitute an SB 288 Major Modification and no further discussion is required.

8. Federal Major Modification / New Major Source

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.

As defined in 40 CFR 51.165, Section (a)(1)(v) and part D of Title I of the CAA, a Federal Major Modification is 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. The significant net emission increase threshold for each criteria pollutant is included in Rule 2201.

[3] Note that the total project increase for CO emissions is well below the 100 ton/year significant increase level for CO emissions in CO attainment areas given in 40 CFR Part 51.165

A Federal Major Modification for a given pollutant can only occur at a stationary source that is a major source for that specific pollutant. The only pollutants for which this facility is a major source are NO_X, CO, and, VOC; therefore, this project is not a Federal Major Modification for any other pollutant. In addition, District Rule 2201 does not include a Federal Major Modification Significance threshold for CO emissions; therefore, the project is not a Federal Major Modification for CO.[4]

The determination of Federal Major Modification is based on a two-step test. For the first step, only the emission *increases* are counted. In step 1, emission decreases cannot cancel out the increases. Step 2 allows consideration of the project's net emissions increase as described in 40 CFR 51.165 and the Federal Clean Air Act Section 182 (e), as applicable.

Step 1: Project Emissions Increase

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

Emission Increase = PE2

The proposed natural gas/digester gas-fired IC engine (ATC N-1237-892-0) is a new unit and is the only unit subject to NSR in this project.

The project's combined total emissions increases for NO_X and VOC are summarized and are compared to the Federal Major Modification Thresholds in the following table.

Federal Major Modification Thresholds for Emission Increases			
Pollutant	**Total Emissions Increases (lb/yr)**	**Thresholds (lb/yr)**	**Federal Major Modification?**
NO_X*	1,940	0	Yes
VOC*	1,820	0	Yes

*If there is any emission increases in NO_x or VOC, this project is a Federal Major Modification and no further analysis is required.

Since there is an increase in NO_x and VOC emissions, this project constitutes a Federal Major Modification. Consequently, as discussed below in the offset section of this evaluation, pursuant to Section 7.4.2.1 of District Rule 2201, NOx and VOC Emission Reduction Credits (ERCs) used to satisfy the offset quantity required under District Rule 2201 must be surplus at the time of use (ATC issuance).

Separately, the Federal Offset Quantities are calculated below.

[4] Note that the total project increase for CO emissions is well below the 100 ton/year significant increase level for CO emissions in CO attainment areas given in 40 CFR Part 51.165

New Major Source

As demonstrated above, this facility is not becoming a Major Source as a result of this project, therefore, this facility is not a New Major Source pursuant to 40 CFR 51.165 a(1)(iv)(A)(3).

Federal Offset Quantity Calculation

The Federal Offset Quantity (FOQ) is only calculated for the pollutants for which a project is a Federal Major Modification or a New Major Source as determined above.

Pursuant to 40 CFR 51.165(a)(3)(ii)(J), the federal offset quantity is the sum of the annual emission changes for all new and modified emission units in a project calculated as the potential to emit after the modification (PE2) minus the actual emissions (AE) for each emission unit times the applicable federal offset ratio.

FOQ = ∑(PE2 – AE) x Federal offset ratio

<u>Actual Emissions</u>

As described in 40 CFR 51.165(a)(1)(xii), actual emissions (AE), as of a particular date, shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

Since the proposed natural gas/digester gas-fired IC engine (ATC N-1237-892-0) is a new unit, AE = 0

<u>Federal Offset Ratio</u>

According the CAA 182(e), the federal offset ratio for VOC and NOx is 1.5 to 1 (due to the District extreme non-attainment status for ozone). Otherwise, the federal offset ratio for PM2.5, PM10, and SOx is 1.0 to 1.

<u>Federal Offset Quantity (FOQ)</u>

Since the only unit subject to NSR included in this project is a new unit,

FOQ = PE2 x Federal offset ratio

NOx **Federal Offset Ratio 1.5**

Permit No.	Post-Project Potential to Emit (PE2) (lb/year)	Actual Emissions (lb/year)	Emissions Change (lb/yr)
N-1237-892-0	1,940	0	1,940
		∑(PE2 – AE) (lb/year):	**1,940**
		Federal Offset Quantity (lb/year): ∑(PE2 – AE) x 1.5	**2,910**
		Federal Offset Quantity (tons/year): ∑(PE2 – AE) x 1.5 ÷ 2,000	**1.46**

VOC **Federal Offset Ratio 1.5**

Permit No.	Post-Project Potential to Emit (PE2) (lb/year)	Actual Emissions (lb/year)	Emissions Change (lb/yr)
N-1237-892-0	1,820	0	1,820
		∑(PE2 – AE) (lb/year):	**1,820**
		Federal Offset Quantity (lb/year): ∑(PE2 – AE) x 1.5	**2,730**
		Federal Offset Quantity (tons/year): ∑(PE2 – AE) x 1.5 ÷ 2,000	**1.37**

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
- Hydrogen sulfide (H2S)[5]
- Total reduced sulfur (TRS) (including H2S)[5]
- Reduced sulfur compounds[5]

[5] For the proposed IC engine, sulfur (primarily H_2S) in the fuel will be converted almost entirely to SO_X during combustion, as a result H_2S emissions will generally be insignificant. The maximum amount of non-fugitive H_2S and total reduced sulfur compounds emitted from the proposed IC engine can be conservatively estimated by assuming that 2% of the sulfur in the fuel used in the IC engine will be emitted as H_2S rather than converted to SO_X. Therefore, non-fugitive H_2S emissions from the proposed IC engine can be estimated as (1,092 lb-SO_X/yr) x 0.02 mol-H_2S/mol-SO_X x (34 lb-H_2S/mol-H_2S)/(64 lb-SO_X/mol-SO_X) = 12 lb-H_2S/yr = 0.006 ton-H_2S/yr. This is well below the applicable PSD threshold of 250 tpy.

Additionally, when evaluating if a facility is a PSD major source all regulated NSR pollutants, including VOC, must be considered regardless of attainment status.

I. Project Location Relative to Class 1 Area

As demonstrated in the “PSD Major Source Determination” Section above, the facility was determined to be a existing PSD Major Source. Because the project is not located within 10 km (6.2 miles) of a Class 1 area – modeling of the emission increase is not required to determine if the project is subject to the requirements of Rule 2410.

II. Project Emission Increase – Significance Determination

a. Evaluation of Calculated Post-project Potential to Emit for New or Modified Emissions Units vs PSD Significant Emission Increase Thresholds

As a screening tool, the post-project potential to emit from all new and modified units is compared to the PSD significant emission increase thresholds, and if the total potentials to emit from all new and modified units are below the applicable thresholds, no futher PSD analysis is needed.

PSD Significant Emission Increase Determination: Potential to Emit (tons/year)					
	NO_2	SO_2	CO	PM	PM_{10}
Total PE from New and Modified Units	1.0	0.5	2.5	0.9	0.9
PSD Significant Emission Increase Thresholds	40	40	100	25	15
PSD Significant Emission Increase?	No	No	No	No	No

As demonstrated above, because the post-project total potentials to emit from all new and modified emission units are below the PSD significant emission increase thresholds, this project is not subject to the requirements of Rule 2410 and no further discussion 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 E.

VIII. Compliance Determination

Rule 2201 New and Modified Stationary Source Review Rule

N-1237-661-5 (Digester with Enclosed Flare)

As discussed in Section VII of this evaluation, the proposed modification of the existing wastewater anaerobic reactor to allow the biogas generated in the reactor to be sent to any equipment that is authorized to utilize biogas does not constitute a New Source Review (NSR) modification.

Pursuant to Section 3.25 of District Rule 2201, a modification is an action including at least one of the following items:

3.25.1.1 Any change in hours of operation, production rate, or method of operation of an existing emissions unit, which would necessitate a change in permit conditions.

The proposed modification does not result in a change in the hours of operation, production rate, or method of operation which would a change in permit conditions.

3.25.1.2 Any structural change or addition to an existing emissions unit which would necessitate a change in permit conditions. A Routine Replacement Emissions Unit shall not be considered to be a structural change.

The proposed modification is not a structural change or addition to an existing emissions unit which would necessitate a change in permit conditions.

3.25.1.3 An increase in emissions from an emissions unit caused by a modification of the Stationary Source when the emissions unit is not subject to a daily emissions limitation.

The proposed modification will not result in an increase in emissions from any emissions unit.

3.25.1.4 Addition of any new emissions unit which is subject to District permitting requirements.

The proposed modification will not result in the addition of any new emissions units that are subject to District permitting requirements.

3.25.1.5 A change in a permit term or condition proposed by an applicant to obtain an exemption from an applicable requirement to which the source would otherwise be subject.

The proposed modification will not change any permit terms or conditions to obtain an exemption from an applicable requirement to which the source would otherwise be subject.

As discussed above, the proposed modification of the permit for Permit N-1237-661-5 does not fall under any of the criteria for a modification for purposes of Rule 2201. Therefore, the proposed non-NSR modification to Permit Unit N-1237-661-5 is not subject to the requirements of Rule 2201 and the following Rule 2201 discussion below will be limited to ATC N-1237-892-0 for the proposed natural gas/biogas-fired IC engine.

A. Best Available Control Technology (BACT)

1. BACT Applicability

Pursuant to District Rule 2201, Section 4.1, 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 Adjusted Increase in Permitted Emissions (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

<u>ATC N-1237-892-0 (Natural Gas/Digester Gas-Fired IC Engine)</u>

As seen in Section VII.C.2 above, the applicant is proposing to install a new natural gas/digester gas-fired IC engine with a PE greater than 2.0 lb/day for NO_X, SO_X (when fueled with digester gas), PM_{10}, CO, VOC, and NH_3. Therefore, BACT is triggered for NO_X, SO_X (when fueled with digester gas), PM_{10}, and VOC. BACT is also triggered for CO because the SSPE2 for CO is greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 above. BACT is not triggered for NH_3 because it results from the use of an SCR system, which is an emissions control device that is not subject to District BACT requirements.

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 for relocation of an emissions unit.

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 for modification of an emissions unit.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does constitute a Federal Major Modification for NO_X and VOC emissions. Therefore BACT is triggered for NO_X and VOC for all emissions units in the project for which there is an emission increase.

2. BACT Guideline

The applicant is proposing to install an IC engine powering a non-emergency electrical generator that can be fueled with natural gas or digester gas without a limit on the fuel that may be used.

<u>When IC Engine is Fueled with Natural Gas</u>

The District does not currently have an approved BACT Guideline for this source category (fossil fuel-fired IC engines powering non-emergency electrical generators). Therefore, a project-specific BACT analysis was performed for the proposed 1,966 bhp IC engine when it is fueled with natural gas based on the District's review of information that was available when the application for this project was deemed complete. (See Appendix F)

<u>BACT Guideline when IC Engine is Fueled with Digester Gas</u>

BACT Guideline 3.3.15 applies to the proposed 1,966 bhp IC engine when it is fueled with digester gas. (See Appendix G)

3. Top-Down BACT Analysis

Pursuant to 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.

<u>BACT for IC Engine when Fueled with Natural Gas</u>

Pursuant to the Top-Down BACT Analysis (See Appendix F), BACT for the proposed IC engine when fueled with natural gas has been satisfied with the following:

NO_X: 0.049 g/bhp-hr
PM_{10}: 0.032 g/bhp-hr
CO: 0.14 g/bhp-hr
VOC: 0.049 g/bhp-hr

BACT for IC Engine when Fueled with Digester Gas

Pursuant to the Top-Down BACT Analysis (See Appendix G), BACT for the proposed IC engine when fueled with digester gas has been satisfied with the following:

NO_X: 0.050 g/bhp-hr
SO_X: Digester fuel sulfur content ≤ 40 ppmv as H_2S
PM_{10}: Digester fuel sulfur content ≤ 40 ppmv as H_2S
CO: 0.14 g/bhp-hr
VOC: 0.050 g/bhp-hr

B. Offsets

1. Offset Applicability

Pursuant to District Rule 2201, Section 4.5, 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	32,061	8,863	19,314	771,585	> 20,000
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets Triggered?	Yes	No	No	Yes	Yes

2. Quantity of District Offsets Required

As seen above, the SSPE2 is greater than the offset thresholds for NO_X, CO, and VOC. Therefore offset calculations will be required for this project.

The quantity of offsets in pounds per year is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
PE2 = Post-Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)

DOR = Distance Offset Ratio, determined pursuant to Section 4.8

As discussed above, since proposed ATC N-1237-892-0 (natural gas/digester gas-fired IC engine) is a new emissions unit, BE = PE1 = 0 for all pollutants from the unit.

2.1 NOx Offsets

As shown in Section VII.C.6 above, the BE from the proposed IC engine are equal to the PE1 since the unit is a new unit.

Also, there is only one emissions unit associated with this project and there are no increases in cargo carrier emissions. Therefore offsets can be determined as follows:

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

PE2 (NO_X) = 1,940 lb/year
BE (NO_X) = 0 lb/year
ICCE = 0 lb/year

Based on an offset ratio of 1.5:1, the amount of NO_X ERCs that need to be withdrawn is:

Offsets Required (lb/year) = ([1,940 – 0] + 0) x 1.5
= 1,940 lb-NO_X/year x 1.5
= 2,910 lb-NO_X/year

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

Quarterly offsets required (lb/qtr) = (2,910 lb-NO_X/year) ÷ (4 quarters/year)
= 727.5 lb-NO_X/qtr

As demonstrated in the calculation above, the quarterly amount of offsets required for this project, when evenly distributed to each quarter, results in fractional pounds of offsets being required each quarter. Since offsets are required to be withdrawn as whole pounds, the quarterly amounts of offsets need to be adjusted to ensure the quarterly values sum to the total annual amount of offsets required.

To adjust the quarterly amount of offsets required, the fractional amount of offsets required in each quarter will be summed and redistributed to each quarter based on the number of days in each quarter. The redistribution is based on the Quarter 1 having the fewest days and the Quarters 3 and 4 having the most days. The redistribution method is summarized in the following table:

Redistribution of Required Quarterly Offsets (where X is the annual amount of offsets, and X ÷ 4 = Y.z)				
Value of z	**Quarter 1**	**Quarter 2**	**Quarter 3**	**Quarter 4**
0.0	Y	Y	Y	Y
0.25	Y	Y	Y	Y+1
0.5	Y	Y	Y+1	Y+1
0.75	Y	Y+1	Y+1	Y+1

Therefore, the appropriate quarterly emissions to be offset are as follows:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	**Total Annual**
727	727	728	728	**2,910**

As discussed above, District offsets are triggered and required for NO_X under NSR. In addition, as demonstrated above, this project does trigger Federal Major Modification requirements for NOx emissions, and federal offset quantities are required for this project for NOx. Pursuant to Section 7.4.2.1 of District Rule 2201, emission reduction credits (ERCs) used to satisfy federal offset quantities for NOx must be creditable and surplus at the time of use (ATC issuance).

Surplus at the Time Of Use Emission Reduction Credits

The applicant has stated that the facility plans to use ERC certificate N-1568-2 to satisfy the federal offset quantities for NO_X required for this project. Pursuant to the ERC surplus analysis in Appendix H, the District has verified that the credits from the ERC certificate provided by the applicant are sufficient to satisfy the federal offset quantities for NO_X required for this project.

Required District and Federal Offset Quantities Summary

The applicant has proposed to use the following NO_X emission reduction certificate:

ERC Certificate	Unreserved Nominal Credits Available			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC # N-1568-2	4,259	4,259	4,259	4,259

	Unreserved Surplus Credits Available			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC # N-1568-2 Surplus Value	4,259	4,259	4,259	4,259

As discussed above, the facility has sufficient credits to fully offset the quarterly NO_X emissions increases associated with this project.

Proposed Rule 2201 Offset Permit Conditions

The following permit conditions will be included on the Authority to Construct (ATC) N-1237-892-0 for the proposed IC engine:

- Prior to operating equipment under this Authority to Construct (ATC), permittee shall surrender NOx emission reduction credits (ERCs) for the following quantity of emissions: 1st quarter - 727 lb, 2nd quarter - 727 lb, 3rd quarter - 728 lb, and 4th quarter - 728 lb. These amounts include the applicable offset ratio specified in Rule 2201, Section 4.8 (as amended 8/15/19). NOx ERCs used to satisfy the offset quantity required under District Rule 2201 must be surplus at the time of issuance of this ATC and the total quantity of ERCs surrendered shall be calculated based on the ERC surplus value percent discount of each ERC certificate used. [District Rule 2201]
- ERC Certificate Number N-1568-2 (or certificates split from this certificate) shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District, upon which this ATC shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this ATC. [District Rule 2201]

2.2 CO Offsets

Pursuant to District Rule 2201, Section 4.6.1, increases in carbon monoxide (CO) in attainment areas are exempt from the offset requirements of District Rule 2201 if the applicant demonstrates to the satisfaction of the APCO that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

The proposed location is in an attainment area for CO. The District's Technical Services Division conducted an Ambient Air Quality Analysis (AAQA) for CO emissions from the proposed project. Refer to Appendix J of this document for the AAQA summary sheet. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an Ambient Air Quality Standard for CO. Therefore, this project is exempt from the offset requirements for CO emissions pursuant to District Rule 2201, Section 4.6.1.

2.3 VOC Offsets

As shown in Section VII.C.6 above, the BE from the proposed IC engine are equal to the PE1 since the unit is a new unit.

Also, there is only one emissions unit associated with this project and there are no increases in cargo carrier emissions. Therefore, offsets can be determined as follows:

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

PE2 (VOC) = 1,820 lb/year

BE (VOC) = 0 lb/year
ICCE = 0 lb/year

Based on an offset ratio of 1.5:1, the amount of VOC ERCs that need to be withdrawn is:

Offsets Required (lb/year) = ([1,820 – 0] + 0) x 1.5
= 1,820 lb-VOC/year x 1.5
= 2,730 lb-VOC/year

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

Quarterly offsets required (lb/qtr) = (2,730 lb-VOC/year) ÷ (4 quarters/year)
= 682.5 lb-VOC/qtr

Therefore, the appropriate quarterly emissions to be offset are as follows:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	**Total Annual**
682	682	683	683	**2,730**

As discussed above, District offsets are triggered and required for VOC under NSR. In addition, as demonstrated above, this project does trigger Federal Major Modification requirements for VOC emissions.

Since District offsets and federal offsets are required, the facility must provide offset amounts equal to the greatest value between the District offset quantity and the federal offset quantity.

Comparison of District vs Federal VOC Offset Quantity			
	DOQ	**FOQ**	**DOQ ≥ FOQ**
VOC	2,730	2,730	**Yes**

As demonstrated above, the District offset quantity required is the same as the federal offset quantity. Therefore, by satisfying the District offset quantities, the facility will satisfy the required federal offset quantities. In addition, pursuant to Section 7.4.2.1 of District Rule 2201, emission reduction credits (ERCs) used to satisfy federal offset quantities for VOC must be creditable and surplus at the time of use (ATC issuance).

Surplus at the Time Of Use Emission Reduction Credits

The applicant has stated that the facility plans to use ERC certificates S-4442-1, S-4751-1, and/or S-4773-1 to satisfy the federal offset quantities for VOC required for this project. Pursuant to the ERC surplus analysis in Appendix H, the District has verified that the credits from the ERC certificate(s) provided by the applicant are sufficient to satisfy the federal offset quantities for VOC required for this project.

Required District and Federal Offset Quantities Summary

The applicant has proposed to use the following VOC emission reduction certificates:

ERC Certificate	Unreserved Nominal Credits Available			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC # S-4751-1	4,498	4,451	5,416	4,808
ERC # C-1404-1	4,409	4,405	4,252	4,131

	Unreserved Surplus Credits Available			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC # S-4751-1 Surplus Value	189	187	227	202
ERC # C-1404-1 Surplus Value	842	841	812	789
Total	1,031	1,028	1,039	991

As discussed above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

Proposed Rule 2201 Offset Permit Conditions

The following permit conditions will be included on Authority to Construct (ATC) N-1237-892-0 for the proposed IC engine:

- Prior to operating equipment under this Authority to Construct (ATC), permittee shall surrender VOC emission reduction credits (ERCs) for the following quantity of emissions: 1st quarter - 682 lb, 2nd quarter - 682 lb, 3rd quarter - 683 lb, and 4th quarter - 683 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 8/15/19). VOC ERCs used to satisfy the offset quantity required under District Rule 2201 must be surplus at the time of issuance of this ATC and the total quantity of ERCs surrendered shall be calculated based on the ERC surplus value percent discount of each ERC certificate used. [District Rule 2201]

- ERC Certificate Numbers S-4751-1 and C-1404-1 (or certificates split from these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District, upon which this ATC shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this ATC. [District Rule 2201]

3. ERC Withdrawal Calculations

The applicant must identify the ERC Certificate(s) to be used to offset the increase of NO_X and VOC emissions for the project. As indicated in previous section, the applicant is proposing to use ERC certificate N-1568-2 to mitigate the increases of NO_X emissions associated with this project and proposing to use ERC certificates S-4751-1 and C-1404-1 to mitigate the increases of VOC emissions associated with this project. See Appendix I for detailed ERC Withdrawal Calculations.

C. Public Notification

1. Applicability

Pursuant to District Rule 2201, Section 5.4, 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 SSIPE 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

As demonstrated in Section VII.C.7 of this evaluation, this project is a Federal Major Modification. Therefore, public noticing is required for this project for Federal Major Modification purposes.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. As seen in Section VII.C.2 above, this project does not include a new emissions unit that has daily emissions greater than 100 lb/day for any pollutant. Therefore public noticing is not required for this project for PE > 100 lb/day from a new emissions unit.

c. Offset Threshold

Public notification is required if the pre-project Stationary Source Potential to Emit (SSPE1) is increased to a level exceeding the offset threshold levels. The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Thresholds				
Pollutant	**SSPE1 (lb/year)**	**SSPE2 (lb/year)**	**Offset Threshold**	**Public Notice Required?**
NO_X	30,121	32,061	20,000 lb/year	No
SO_X	7,771	8,863	54,750 lb/year	No
PM_{10}	17,494	19,314	29,200 lb/year	No
CO	359,468	364,565	200,000 lb/year	No
VOC	> 20,000	> 20,000	20,000 lb/year	No

As demonstrated above, there were no offset thresholds surpassed with this project; therefore public noticing is not required for surpassing an offset threshold.

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?**
NO_x	32,061	30,121	1,940	20,000 lb/year	No
SO_x	8,863	7,771	1,092	20,000 lb/year	No
PM_{10}	19,314	17,494	1,820	20,000 lb/year	No
CO	364,565	359,468	5,097	20,000 lb/year	No
VOC	> 20,000	> 20,000	1,820	20,000 lb/year	No
NH_3	Not Calculated	Not Calculated	1,638	20,000 lb/year	No

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

e. Title V Significant Permit Modification

As shown in the Discussion of Rule 2520 below, this project constitutes a Title V significant modification. Therefore, public noticing for a Title V significant modification is required for this project.

2. Public Notice Action

As discussed above, public noticing is required for this project for Federal Major Modifications for NO_X and VOC emissions and for a Title V significant modification. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be electronically published on the District's website prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Since the digester and emergency flare under permit N-1237-661 are not being modified and are not subject to District Rule 2201, the existing DEL permit conditions will be included on the draft ATC issued in this project.

Proposed Rule 2201 (DEL) Conditions for N-1237-892-0 (Natural Gas/Digester Gas-Fired IC Engine)

For the natural gas/digester gas-fired IC engine, the DELs for NO_X, PM_{10}, CO, and VOC during commissioning are stated in the form of maximum emission factors (g/bhp-hr), the maximum engine horsepower rating (1,966 bhp), and the maximum operational time of 24 hours per day. The DEL for SO_X is based on the maximum H_2S content of the digester gas.

Proposed Rule 2201 (DEL) Conditions for the Engine during Commissioning and Normal Operation

- 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 and 40 CFR 60.4243]
- This engine shall only be fueled with PUC-regulated natural gas, digester gas, or a blend of PUC-regulated natural gas and digester gas. [District Rules 2201, 4702, and 4801]
- The sulfur content of the digester gas and natural gas/digester gas blends used as fuel in this engine shall not exceed 40 ppmv as H2S. An averaging period of up to one calendar day in length may be utilized for demonstration of compliance with the digester gas sulfur content limit. [District Rules 2201, 4702, and 4801]
- Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4101]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period

The following condition will be included on the ATC permit:

- During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 0.6 g-NOx/bhp-hr, 0.05 g-PM10/bhp-hr, 0.14 g-CO/bhp-hr, or 0.050 g-VOC/bhp-hr. [District Rule 2201]

In addition, the following conditions will be included on the ATC permit to minimize emissions during the commissioning period.

- 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]
- The commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall

terminate when the engine has completed initial tuning and testing and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 50 hours of operation. [District Rule 2201]

- The owner/operator shall minimize the emissions from the engine to the maximum extent feasible during the commissioning period. [District Rule 2201]
- The oxidation catalyst(s) shall be installed and ready for operation prior to commencement of the commissioning period. [District Rule 2201]
- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or 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/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
- The permittee shall prepare and maintain a summary of activities to be performed during the commissioning period 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, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
- The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 50 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. Upon completion of these activities, the unused balance of the 50 firing hours without abatement shall expire. [District Rule 2201]

<u>Proposed Rule 2201 (DEL) Conditions during Normal Operation</u>:

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.049 g-NOx/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.050 g-NOx/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 4.1 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.032 g-PM10/bhp-hr when fueled with natural gas, and 0.05 g-PM10/bhp-hr when fueled with digester gas or a natural gas/digester gas blend; 0.14 g-CO/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.14 g-CO/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 19.5 ppmvd CO @ 15%); and 0.049 g-VOC/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.050 g-NOx/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 12.0 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201, 4102, and 4702, and 40 CFR 60.4233]
- This engine shall be operated within the ranges that the source testing has shown result in pollution emission rates within the emissions limits as specified on this permit. [District Rules 2201 and 4702]

E. Compliance Assurance

Since the digester and emergency flare under permit N-1237-661 are not being modified and are not subject to District Rule 2201, the existing compliance assurance permit conditions will be included on the draft ATC issued in this project.

The following sections will only apply to the proposed natural gas/digester gas-fired IC engine.

1. Source Testing

The proposed 1,966 bhp natural gas/digester gas-fired engine is subject to District Rule 4702 - Internal Combustion Engines. District Rule 4702, Section 6.3.2.1 requires source testing of NO_X, CO, and VOC emissions at least once every 24 months for a non-agricultural spark-ignited IC engine. The proposed IC engine is also subject to 40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. 40 CFR 60, Subpart JJJJ requires that a performance test be conducted for uncertified engines rated 500 bhp or more every 8,760 hours of operation or every 3 years, whatever comes first. The periodic source testing required by District Rule 4702 and 40 CFR 60, Subpart JJJJ will ensure compliance with the applicable New Source Review (NSR) requirements NO_X, CO, and VOC. Therefore, source testing for NO_X, CO, and VOC will be required within 60 days of initial start-up and at least once every 8,760 hours of operation or 24 months thereafter, whichever comes first. Since the control equipment will include an SCR system, periodic testing of ammonia slip will also be required. In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. The PM_{10} emissions from the engine are not expected to change significantly over time as long as the quality of the gas used to fuel the engine remains consistent. The facility will be required to periodically monitor the sulfur content of the digester gas fuel, which should ensure that the quality of the digester gas fuel is consistent. Therefore, initial PM_{10} source testing will be required to demonstrate compliance with the PM_{10} emission limit, but ongoing PM_{10} source testing will not be required.

The following conditions will be included on the ATC permit for the IC engine:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the California Air Resources Board (CARB) document titled Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]
- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days of initial start-up. [District Rules 1081, 2201, and 4702, and 40 CFR 60.4243]

- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 8,760 hours of operation or 24 months, whichever comes first. [District Rules 1081, 2201, and 4702 and 40 CFR 60.4243]
- 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 and EPA within 60 days after completion of the source test. [District Rule 1081 and 40 CFR 60.4245]
- 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 and 40 CFR 60.4244]
- For emissions source testing, the arithmetic average of three 60-consecutive-minute test runs shall apply. Each test run shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. 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 (however, VOC may also be reported as propane only for demonstration of compliance with the VOC limits in 40 CFR 60 Subpart JJJJ). NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rule 4702 and 40 CFR 60.4244]
- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E; CO (ppmv) - EPA Method 10; VOC (ppmv) - EPA Method 18, or 25A or 25B; stack gas oxygen - EPA Method 3 or 3A; stack gas velocity/volumetric flowrate - 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 EPA and the District may be used to address the source testing requirements of this permit. [District Rules 1081, 2201, and 4702]
- 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 EPA and the District. [District Rules 2201 and 4702]
- Fuel sulfur content analysis of the digester gas used to fuel this engine shall be performed within 60 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate, or an alternative method approved by EPA and the District. [District Rules 2201 and 4702]
- Fuel sulfur content analysis of the digester gas used to fuel this engine shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate, or an alternative method approved by EPA and the District. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

2. Monitoring

As stated above the proposed natural gas/digester gas-fired IC engine is subject to District Rule 4702. District Rule 4702, Section 5.9.1 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 5.9.9 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 inspections and monitoring for engines equipped with non-certified control devices in order to demonstrate compliance with the emission limits in District Rule 4702. In addition, as discussed later in this evaluation, the proposed natural gas/digester gas-fired IC engine is also subject to 40 CFR 64 – Compliance Assurance Monitoring (CAM) for NO_X emissions, which requires daily monitoring of parameters to ensure compliance with the NO_X emission limit of the permit. Therefore, daily monitoring of NO_X and O_2 concentrations and, as proposed by the applicant, monthly monitoring of CO and O_2 concentrations in accordance with pre-approved alternate monitoring plan “A” within District Policy SSP 1810 will be required. Since the engine will be equipped with SCR, monthly monitoring of ammonia slip will also be required.

The following conditions will be included on the ATC permit for the proposed IC engine to ensure compliance:

- Coincident with the end of the commissioning period, the permittee shall monitor and record the stack concentration of NOx and O2 at least once every day (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702, and 40 CFR 64]
- The permittee shall monitor and record the stack concentration of CO and O2 at least once every calendar month (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. 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. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- In-stack emission monitors shall be calibrated using EPA protocol calibration gases a minimum of once within every 30 days. Records of calibration dates, instruments calibrated, gas readings prior to calibration, calibration gases used, and calibration gas certification and expiration dates shall be maintained. [District Rules 1080 and 4702, and 40 CFR 64]
- Portable emission monitors shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Calibration records shall be shall be maintained. [District Rules 1080 and 4702, and 40 CFR 64]
- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar month 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 month. [District Rules 2201 and 4102]

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer, the District-approved in-stack emission monitor(s), or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), 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(s) 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, and 40 CFR 64]
- 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 and any in-stack emission monitors 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]

Because of the variable composition of digester gas, additional monitoring of the fuel sulfur content of the digester gas will be required. The following conditions will be placed on the ATC permit for the IC engine to ensure compliance:

- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; District-approved test methods, including EPA Method 11 or EPA Method 15, ASTM Method D1072, D1945, D4084, D4468, D4810 or D5504; a continuous analyzer employing gas chromatography; a continuous fuel gas monitor

that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; or an alternative method approved by EPA and the District. The permittee shall maintain records of any in-line monitors used to demonstrate compliance with the digester gas sulfur content limit of this permit, including the make, model, and detection limits of the monitor(s). [District 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 included on the ATC permit for the proposed IC engine:

- This engine shall be equipped with an operational non-resettable elapsed time meter. [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 maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of portable emission analyzer(s) and in-stack emission analyzer(s), (4) emission 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, and 40 CFR 64]
- 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 hours of operation for commissioning of the engine, the total hours of operation, the type and quantity of each fuel used, 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, 4701, and 4702, and 40 CFR 60.4243 and 40 CFR 60.4245]
- Records shall be maintained of the composition of the fuel used during each source test, including the percent blend of natural gas and digester gas on a volumetric and heat input basis in the fuel used. [District Rule 2201]
- The permittee shall document that the natural gas used as fuel in the engine is from a PUC regulated source. Valid purchase contracts, supplier certifications, tariff sheets, or transportation contacts may be used to satisfy this requirement. [District Rules 2201 and 4702]
- Records shall be maintained of the total hours of operation of this engine, calculated on a rolling 12-month basis. [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. [District Rules 2201 and 4702 and 40 CFR 60.4245]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

As stated above, the proposed 1,966 bhp engine is subject to 40 CFR 60, Subpart JJJJ. 40 CFR 60, Subpart JJJJ requires uncertified engines rated 500 bhp or more to submit an initial notification to EPA. 40 CFR 60, Subpart JJJJ and District Rule 4702 also require the operator or owner of the engine to report source test results within 60 day of the completion of testing. Therefore, the following conditions will be included on the permit:

- The results of each source test shall be submitted to the District and EPA within 60 days after completion of the source test. [District Rule 1081 and 40 CFR 60.4245]
- Notification of the date construction of this engine commenced shall be submitted to the District and EPA and shall be postmarked no later than 30 days after such date as construction commenced. The notification shall contain the following information: 1) Name and address of the owner or operator; 2) The address of the affected source; 3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; 4) Emission control equipment; and 5) Fuel used. Notification of construction and copies of source test results shall be submitted to EPA at the following address: Director, Air Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, CA 94105. [40 CFR 60.4245]

F. Ambient Air Quality Analysis (AAQA)

Section 4.14 of District Rule 2201 requires that an AAQA 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 J 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 PM_{10} 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 PM_{10} and $PM_{2.5}$.

G. Compliance Certification

Section 4.15.2 of this Rule requires the owner of a New Major Source or a source undergoing a Federal Major Modification to demonstrate to the satisfaction of the District that all other Major Sources owned by such person and operating in California are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. As discussed in Section VIII above, this facility is not a New Major Source, but this project does constitute a Federal Major Modification, therefore this requirement is applicable. E & J Gallo Winery's compliance certification is included in Appendix K.

H. Alternate Siting Analysis

The current project occurs at an existing facility. The applicant proposes to install a new 1,966 bhp natural gas/digester gas-fired lean-burn IC engine that will power a 1,429 kW electrical generator and will provide electricity and heat for operations at the existing winery.

Since the project will utilize digester gas from the wastewater generated by the existing winery and will provide electric power and heat to be used at the same location, the existing site will result in the least possible impact from the project. Alternative sites would involve the relocation and/or construction of various support structures on a much greater scale, and would therefore result in a much greater impact.

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

This facility is subject to this Rule, and has received their Title V Operating Permit. A significant permit modification is defined as a "permit amendment that does not qualify as a minor permit modification or administrative amendment."

Minor permit modifications are permit modifications that are not Title I modifications as defined in Rule 2520, are not modifications as defined in section 111 or 112 of the Federal Clean Air Act, and are not major modifications under the prevention of significant deterioration (PSD) provisions of Title I of the CAA or under EPA PSD regulations. Since this project is a Title I modification (i.e. Federal Major Modification) and involves the installation of a new emission unit that is subject to a New Source Performance Standard (NSPS), the proposed project is a modification under the Federal Clean Air Act. As a result, the proposed project constitutes a Significant Modification to the Title V Permit.

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

The following conditions will be included on the ATC permits:

- {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201]
- {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

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.

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 bhp (except lean burn engines with a maximum engine power greater than or equal to 500 bhp and less than 1,350 bhp); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 bhp and less than 1,350 bhp; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 bhp; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 kW (25 bhp).

The proposed engine is a 1,966 bhp natural gas/digester gas-fired lean-burn SI ICE that will be constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the proposed engine is subject to this subpart.

Pursuant to Section 60.4233(d), owners and operators of stationary SI ICE with a maximum engine power greater than 19 kW (25 bhp) and less than 75 kW (100 bhp) (except gasoline and rich burn engines that use LPG) must comply with the emission standards for field testing in 40 CFR 1048.101(c) for their non-emergency stationary SI ICE and with the emission standards in 40 CFR 60, Subpart JJJJ, Table 1 for their emergency stationary SI ICE. Owners and operators of stationary SI ICE with a maximum engine power greater than 19 kW (25 bhp) and less than 75 kW (100 bhp) manufactured prior to January 1, 2011, that were certified to the standards in 40 CFR 60, Subpart JJJJ, Table 1 applicable to engines with a maximum engine power greater than or equal to 100 bhp and less than 500 bhp, may optionally choose to meet those standards.

The proposed IC engine has a power rating greater than 100 bhp (75 kW); therefore, this section is not applicable.

Pursuant to Section 60.4233(e), owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 kW (100 bhp) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in 40 CFR 60, Subpart JJJJ, Table 1 for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 bhp (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in 40 CFR 60, Subpart JJJJ, Table 1, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.

The proposed engine is a 1,966 bhp natural gas/digester gas-fired lean-burn SI ICE that is not certified and will be constructed after June 12, 2006; therefore, the engine is subject to the emission standards in Table 1 of this subpart.

The requirements contained in 40 CFR 60, Subpart JJJJ, Table 1 for spark-ignited engines subject to 40 CFR 60, Subpart JJJJ are summarized in the table below:

Table 1 to Subpart JJJJ of Part 60 - NO_X , CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Engine Type and Fuel	Maximum Engine Power	Manufacture Date	Emission Standards[a] g/HP-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC[d]	NO_X	CO	VOC[d]
Non-Emergency SI Natural Gas [b] and Non-Emergency SI Lean Burn LPG [b]	100 ≤ bhp < 500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60
Non-Emergency SI Lean Burn Natural Gas and LPG	500 ≤ bhp < 1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	bhp ≥ 500	7/1/2007	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500 ≥ bhp <1,350)	bhp < 500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	bhp ≥ 500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas Lean Burn	500 ≤ bhp < 1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25 < bhp < 130	1/1/2009	[c] 10	387	N/A	N/A	N/A	N/A
	bhp ≥ 130		2.0	4.0	1.0	160	540	86

[a] Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/hp-hr or ppmvd at 15 percent O2.

[b] Owners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake hp located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2a do not have to comply with the CO emission standards of Table 1 of this subpart.

[c] The emission standards applicable to emergency engines between 25 hp and 130 hp are in terms of NO_X + HC.

[d] VOC emission concentrations reported as propane; For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

The emission limits for the proposed IC engine will satisfy the applicable standards of Table 1 of 40 CFR 60, Subpart JJJJ and the following previously proposed condition will be included on the ATC permit:

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.049 g-NOx/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.050 g-NOx/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 4.1 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.032 g-PM10/bhp-hr when fueled with natural gas, and 0.05 g-PM10/bhp-hr when fueled with digester gas or a natural gas/digester gas blend; 0.14 g-CO/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.14 g-CO/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 19.5 ppmvd CO @ 15%); and 0.049 g-VOC/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.050 g-NOx/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 12.0 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201, 4102, and 4702, and 40 CFR 60.4233]

Pursuant to Section 60.4234, an owner or operator of a stationary SI internal combustion engine must operate and maintain the engines such that they achieve the emission standards as required in 40 CFR 60.4233 over the entire life of the engine.

District Rule 4702 and the ATC permit for the proposed engine require adequate periodic monitoring to ensure that the applicable emission limits contained in the permit are met. Therefore, the requirements of this section will be satisfied.

Pursuant to Section 60.4243, an owner or operator of a non-certified stationary SI internal combustion engine rated greater than 500 bhp must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, an initial performance test must be conducted and subsequent performance testing must be conducted every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

The operator of the proposed engine is also required to maintain records of maintenance and periodically source test to demonstrate compliance with District Rule 4702; therefore, the following conditions will be included on the ATC permit for the engine:

- 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 and 40 CFR 60.4243]
- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days of initial start-up. [District Rules 1081, 2201, and 4702, and 40 CFR 60.4243]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 8,760 hours of operation or 24 months, whichever comes first. [District Rules 1081, 2201, and 4702 and 40 CFR 60.4243]
- 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 hours of operation for commissioning of the engine, the total hours of operation, the type and quantity of each fuel used, 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, 4701, and 4702, and 40 CFR 60.4243 and 40 CFR 60.4245]

Section 60.4243(g) states, "It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times." Pursuant to the April 24, 2008 letter from the US EPA Office of Compliance to Jonathon Pettit of the Idaho Department of Environmental Quality, "The provisions of 40 CFR Part 60, Section 60.4243(g) are not intended to apply to lean burn engines." [6] The proposed engine is a lean burn engine; therefore, this section does not apply.

Section 60.4244 requires that three separate test runs be conducted for each performance test and that each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour. The following previously proposed condition will be included on the ATC permit for the engine:

- For emissions source testing, the arithmetic average of three 60-consecutive-minute test runs shall apply. Each test run shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. 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 (however, VOC may also be reported as propane only for demonstration of compliance with the VOC limits in 40 CFR 60 Subpart JJJJ). NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rule 4702 and 40 CFR 60.4244]

Section 60.4245(a) requires owners and operators of stationary SI ICEs to maintain the following records:

1) All notifications submitted to comply with 40 CFR 60, Subpart JJJJ and all documentation supporting any notification;
2) For certified engines, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90, 1048, 1054, and 1060, as applicable;
3) For engines that are not certified engine or certified engines operating in a non-certified manner and subject to Section 60.4243(a)(2), documentation that the engine meets the applicable emission standards

The following previously proposed condition will be included on the ATC permit for the engine:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 2201 and 4702 and 40 CFR 60.4245]

[6] See EPA RICE NESHAP and ICE NSPS Applicability Determinations:
https://www.epa.gov/sites/default/files/2016-11/documents/rice_neshap_nsps_applicability_determinations.pdf

Section 60.4245(c) requires owners and operators of stationary SI ICE greater than or equal to 500 bhp that have not been certified by an engine manufacturer to meet the emission standards in Section 60.4231 to submit an initial notification as required in Section 60.7(a)(1). The notification must include the following:

1) Name and address of the owner or operator;
2) The address of the affected source;
3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;
4) Emission control equipment; and
5) Fuel used

The following condition will be included on the ATC permit for the engine:

- Notification of the date construction of this engine commenced shall be submitted to the District and EPA and shall be postmarked no later than 30 days after such date as construction commenced. The notification shall contain the following information: 1) Name and address of the owner or operator; 2) The address of the affected source; 3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; 4) Emission control equipment; and 5) Fuel used. Notification of construction and copies of source test results shall be submitted to EPA at the following address: Director, Air Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, CA 94105. [40 CFR 60.4245]

Section 60.4245(d) requires owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in §60.4244 within 60 days after the test has been completed.

The following previously proposed condition will be included on the ATC permit for the IC engine:

- The results of each source test shall be submitted to the District and EPA within 60 days after completion of the source test. [District Rule 1081 and 40 CFR 60.4245]

Table 2 of 40 CFR 60, Subpart JJJJ specifies methods and procedures for performance testing to demonstrate compliance with the applicable emission limits. The following previously proposed condition will be included on the ATC permit for the engine:

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E; CO (ppmv) - EPA Method 10; VOC (ppmv) - EPA Method 18, or 25A or 25B; stack gas oxygen - EPA Method 3 or 3A; stack gas velocity/volumetric flowrate - 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 EPA and the District may be used to address the source testing requirements of this permit. [District Rules 1081, 2201, and 4702]

Conclusion

The applicable requirements of 40 CFR 60, Subpart JJJJ will be incorporated into the conditions of the ATC permit for the IC engine and compliance with the applicable requirements of 40 CFR 60, Subpart JJJJ is expected.

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

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

The requirements of 40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines are applicable to stationary reciprocating internal combustion engines (RICE) located at major and area sources of hazardous air pollutant (HAP) emissions. The requirements of 40 CFR 63, Subpart ZZZZ are discussed below.

40 CFR 63, Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines

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.

This facility is an Area Source as defined in this subpart.[7] 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 shown above, the proposed spark-ignited engine will comply with 40 CFR 60, Subpart JJJJ; therefore, the engine is expected to comply with 40 CFR 63, Subpart ZZZZ.

[7] Although the facility has the potential to emit a significant amount of VOCs from the wine fermentation and storage tanks at the facility, nearly all VOC emissions from the wine fermentation and storage tanks are ethanol, which is not a HAP.

Rule 4101 Visible Emissions

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

Because the existing flare will only combust excess digester gas and the proposed IC engine will only be fueled with gaseous fuel (natural gas and digester gas), visible emissions from the flare and proposed IC engine are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will be included on the proposed ATC permits 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.

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.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification of an existing source shall not result in an increase in cancer risk greater than the District's significance level (20 in a million) and shall not result in acute and/or chronic risk indices greater than 1.

According to the Technical Services Memo for this project, the total facility prioritization score including this project was greater than one. Therefore, a Health Risk Assessment (HRA) was required to determine the short-term acute and long-term chronic exposure from this project. Because there is no increase in emissions from Permit Unit N-1237-661 for the digester with an enclosed flare, only the health risk from the proposed ATC N-1237-892 for the 1,966 bhp natural gas/digester gas-fired IC engine was evaluated.

The results of the Risk Management Review (RMR) are summarized in the table below.

RMR Summary						
Units	**Prioritization Score**	**Acute Hazard Index**	**Chronic Hazard Index**	**Maximum Individual Cancer Risk**	**T-BACT Required?**	**Special Permit Requirements?**
ATC N-1237-892-0 (1,966 bhp Natural Gas/Digester Gas-Fired IC Engine)	0.76	0.06	0.01	3.23E-07	No	Yes
Project Totals	0.76	0.06	0.01	3.23E-07		
Facility Totals	> 1	0.26	0.10	9.25E-07		

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.

In accordance with District policy APR 1905, no further analysis is required, and compliance with District Rule 4102 requirements is expected.

See Appendix J: Risk Management Review Summary

The following condition will be listed on the ATC permit for the IC engine to ensure that the operation of the unit is consistent with the RMR:

ATC N-1237-892-0 (Natural Gas/Digester Gas-Fired IC Engine)

- {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.

ATC N-1237-661-5 (Digester with Enclosed Flare)

$$0.008\ \frac{lb-PM}{MMBtu} \times \frac{1\ MMBtu}{8{,}784\ dscf} \times \frac{7{,}000\ grain}{1\ lb} = 0.006\,\frac{grain}{dscf}$$

Since 0.006 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

ATC N-1237-892-0 (1,966 bhp Natural Gas/Digester Gas-Fired IC Engine)

The maximum PM concentration emitted from the proposed IC engine, which results from the combustion of digester gas fuel, is calculated below.

$$0.015\ \frac{lb-PM}{MMBtu}\times\frac{1\ MMBtu}{8{,}784\ dscf}\times\frac{7{,}000\ grain}{1\ lb}=0.012\frac{grain}{dscf}$$

Since 0.012 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be included on the proposed ATC permits to ensure compliance:

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

District Rule 4311 Flares

The purpose of this rule to limit the emissions of volatile organic compounds (VOC), oxides of nitrogen (NO_X), and sulfur oxides (SO_X) from the operation of flares.

The existing flare (ATC N-1237-661-5) is subject to Rule 4311. The requirements of Rule 4311 that apply to the existing flare are discussed below.

Section 5.0 - Requirements

Pursuant to Section 5.1, flares that are permitted to operate only during an emergency are not subject to the requirements of Sections 5.7, 5.8, 5.9 and 5.10.

The existing flare is an emergency flare; therefore, the requirements of Sections 5.7, 5.8, 5.9 and 5.10 are not applicable.

The following conditions will be included as a mechanism to ensure compliance:

- The flare shall be operated only for maintenance, testing, required regulatory purposes, and during periods where both engines, permits N-1237-605 and N-1237-606, cannot be operated due to an emergency, as defined in this permit. Operation of the flare for maintenance, testing, and required regulatory purposes shall not exceed 200 hours per year. [District Rule 2201 and 4311]
- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation of the flare. [District Rules 2201 and 4311]

Section 5.3 requires that a flame always be present in the flare whenever combustible gases are present. The following condition will be included on the ATC permit for the flare:

- A flame shall be present at all times in the flare whenever combustible gases are vented through the flare. [District Rule 4311]

Section 5.4 requires that the flare be equipped with either an automatic ignition system or operated with a continuous pilot. Per the applicant, this unit is equipped with an automatic ignition system.

The following condition will be included on the ATC permit for the flare:

- The flare outlet shall be equipped with an automatic ignition system, or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311]

Section 5.5 requires that, except for flares equipped with a flow-sensing ignition system, flares must be equipped with a device to monitor and confirm operation of the pilot flame. The following condition will be included on the ATC permit:

- Unless the flare is equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. All pilot monitor downtime shall be reported annually pursuant to Rule 4311, Section 6.2.3.6. [District Rule 4311]

Section 5.6 requires that flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot must use purge gas for purging. The following condition will be included on the ATC permit:

- Flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rule 4311]

As discussed above, the flare is an emergency flare and is exempt from Sections 5.7, 5.8, 5.9 and 5.10.

Section 5.11 - Flare Minimization Plan prohibits flaring at petroleum refineries and major sources, except landfill operations, unless it is consistent with an approved flare minimization plan (FMP), pursuant to Section 6.5 or is caused by an emergency and is necessary to prevent an accident, hazard, or release of vent gas directly to the atmosphere. The existing flare is located at a major source. Therefore, a flare minimization plan is required.

The following condition will be included on the ATC permit:

- Flaring is prohibited unless it is consistent with an approved flare minimization plan (FMP), pursuant to District Rule 4311, Section 6.5, and all commitments listed in that plan have been met. This standard does not apply if the APCO determines that the flaring is caused by an emergency as defined by District Rule 4311, Section 3.10 and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere. [District Rule 4311]

Section 5.12 - Petroleum Refinery SO_2 Performance Targets establishes SO_2 emission reduction standards for petroleum refinery flares. The existing flare will not be located at a petroleum refinery. Therefore, this section does not apply.

Section 5.13 requires the operator of a flare at a petroleum refinery or major source, except landfill operations, subject to flare minimization requirements pursuant to Section 5.11 to monitor the vent gas flow to the flare with a flow measuring device and to maintain records pursuant to Section 6.1.7. Flares that the operator can verify, based on permit conditions, are not capable of producing reportable flare events pursuant to Section 6.2.2 shall not be required to monitor vent gas flow to the flare. Pursuant to Section 3.40, a Reportable Flaring Event is any flaring where more than 500,000 standard cubic feet of vent gas is flared per calendar day, or where sulfur oxide emissions are greater than 500 pounds per calendar day.

The existing flare is limited to operate no more than 200 hours/year which equates to 7,200,000 scf per day (200 hr/year x 60 min/hr x 600 scf/min); therefore, the following condition will be included on the ATC:

- The operator shall monitor and record the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. [District Rule 4311]

Section 5.14 requires that on and after January 1, 2024, the operator of a flare subject to the annual throughput thresholds in Table 2 shall monitor the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. The operator shall determine the heating value (Btu per cubic foot) of the vent gas annually in accordance with Section 6.3.6. The operator shall maintain records pursuant to Section 6.1.7. Flares that the operator can verify, based on permit conditions, are not capable of exceeding the annual throughput thresholds in Table 2 shall not be required to monitor vent gas flow to the flare. The flare is not currently subject to the annual throughput thresholds in Table 2; therefore, this section does not apply at this time.

Section 5.15 requires the operator of a petroleum refinery or a flare at a major source, except landfill operations, with a flaring capacity equal to or greater than 50 MMBtu/hr to monitor the flare pursuant to Sections 6.6, 6.7, 6.8, 6.9, and 6.10 and requires that effective on and after January 1, 2024, the operator of any flare with a flaring capacity equal to or greater than 50 MMBtu per hour shall monitor the flare pursuant to Sections 6.6, 6.7, 6.8, 6.9, and 6.10. The flare is rated less than 50 MMBtu/hr. Therefore, this section does not apply.

<u>Section 6.0 - Administrative Requirements</u>

Section 6.1 – Recordkeeping requires that the following records shall be maintained, retained on-site for a minimum of five years, and made available to the APCO, ARB, and EPA upon request:

6.1.1 Copy of the compliance determination conducted pursuant to Section 6.4.1
6.1.2 Copy of the source testing result conducted pursuant to Section 6.4.2
6.1.3 For flares used during an emergency, record of the duration of flare operation, amount of gas burned, and the nature of the emergency situation

6.1.4 Operators claiming an exemption pursuant to Section 5.2 shall record annual hours of operation or annual throughput necessary to demonstrate an exemption under that section
6.1.5 A copy of the approved flare minimization plan pursuant to Section 6.5
6.1.6 A copy of annual reports submitted to the APCO pursuant to Section 6.2
6.1.7 Monitoring data collected pursuant to Sections 5.13, 5.14, 6.6, 6.7, 6.8, 6.9, and 6.10

The following conditions will be included on the ATC permit:

- All records shall be maintained and retained on-site for a minimum of five years, and shall be made available for District inspection upon request. [District Rules 2201 and 4311]
- Permittee shall maintain records of the following when the flare is used during an emergency: duration of flare operation, amount of gas burned, and the nature of the emergency situation. [District Rule 4311]
- Permittee shall maintain the following records: a copy of the approved flare minimization plan pursuant to Section 6.5; a copy of annual reports submitted to the APCO pursuant to Section 6.2 of District Rule 4311. [District Rule 4311]
- The operator shall monitor and record the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. [District Rule 4311]

Section 6.2.1 – Unplanned Flaring Event requires the operator of a flare subject to flare minimization plans pursuant to Section 5.11 to notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The following condition will be included on the permit:

- The operator shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311]

Section 6.2.2 – Reportable Flaring Event requires that effective on and after July 1, 2012, and annually thereafter, except for flares meeting the emission limits in Table 3, the operator of a flare subject to flare minimization plans pursuant to Section 5.11 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined Section 3.0 that occurred during the previous 12 month period. Beginning January 1, 2024, the report shall be submitted within 30 days following the end of the previous calendar year.

The following condition will be included on the ATC permit for the flare:

- The operator shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the previous calendar year. The report shall include, but is not limited to all of the following: 1) The results of an investigation to determine the primary cause and contributing factors of the flaring event; 2) Any prevention measures considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented; 3) If appropriate, an explanation of why the flaring was an emergency and necessary to prevent accident, hazard or release of vent gas to the atmosphere, or where, due to a regulatory mandate to vent a flare, it cannot be recovered, treated and used as a fuel gas at the facility; and 4) The date, time, and duration of the flaring event. [District Rule 4311]

Section 6.2.3 requires that effective until January 1, 2024, the operator of a flare at a petroleum refinery or major source, except landfill operations, subject to flare monitoring requirements pursuant to Sections 5.13, 5.14, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO within 30 days following the end of each 12 month period. Effective on and after January 1, 2024, and annually thereafter, the operator of any flare subject to flare monitoring requirements pursuant to Sections 5.13, 5.14, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report in an electronic format approved by the District to the APCO within 30 days following the end of each calendar year for all required monitoring under those sections.

Since Sections 6.2.3.2-7 are not applicable, only the requirements from 6.2.3.1 and 6.2.3.8 are applicable. The following condition will be included on the ATC permit for the flare:

- The operator shall submit an annual report to the APCO within 30 days following the end of each 12 month period. The report shall include the following: the total volumetric flow of vent gas in standard cubic feet for each day for the previous calendar year; a flow verification report which shall include flow verification testing pursuant to Section 6.3.5 of Rule 4311. [District Rule 4311]

Section 6.3 specifies that the test methods listed in the following tables must be used to demonstrate compliance with Rule 4311, unless alternate equivalent test methods have been approved by the APCO and EPA.

Rule 4311 Test Methods for NO_X, VOC, O_2, and Halogenated Compounds	
Compound or Parameter Measured	**Approved Test Methods**
VOC, measured and calculated as carbon	EPA Method 25, except when the outlet concentration must be below 50 ppm in order to meet the standard, in which case Method 25a may be used
Halogenated exempt compounds	EPA Method 18 or ARB Method 422 “Determination of Volatile organic Compounds in Emission from Stationary Sources”
NO_X emissions in pounds per million BTU	EPA Method 19
NO_X and O_2 concentrations (ppmv)	EPA Method 3A, EPA Method 7E, or ARB 100

Rule 4311 Testing and Sampling Methods for Monitoring Flare Vent Gas Composition	
Compound or Parameter Measured	**Approved Test Methods**
Total hydrocarbon content and methane content of vent gas	ASTM Method D 1945-96, ASTM Method UOP 539-97, EPA Method 18, or EPA Method 25A or 25B

Rule 4311 Testing and Sampling Methods for Monitoring Flare Vent Gas Composition	
Compound or Parameter Measured	**Approved Test Methods**
Hydrogen sulfide content of vent gas	ASTM Method D 1945-96, ASTM Method UOP 539-97, ASTM Method D 4084-94, or ASTM Method D 4810-88
Minimum sampling frequency for continuous analyzer employing gas chromatography	At least one sample every 30 minutes
Total reduced sulfur content of vent gas monitored using continuous analyzers not employing gas chromatography	EPA Method D4468-85

Rule 4311 Flare Vent Gas Flow Verification Test Methods	
Parameter Measured	**Approved Test Methods**
Flare vent gas flow rate	EPA Methods 1 and 2; verification method recommended by the manufacturer of the flow monitoring equipment; tracer gas dilution or velocity; or other flow monitors or process monitors that can provide comparison data on a vent stream that is being directed past the ultrasonic flow meter

Rule 4311 Flare Gas Heating Value Test Methods	
Parameter Measured	**Approved Test Methods**
Heating value of flare gas	ASTM D 1826-88 or ASTM D 1945-81 in conjunction with ASTM D 3588-89; alternately, an operator may elect to use a default heating value from Rule 4311, Table 4

Rule 4311, Table 4 – Default Flare Gas Heating Values	
Flare Category	**Heating Value (Btu/scf)**
Flares at Oil and Gas Operations or Chemical Operations	1,000
Flares at Landfill Operations	500
Flares at Digester Operations	600

The following condition will be included on the ATC permit to require that any testing will use the approved test methods from Section 6.3 of District Rule 4311.

- For purposes of the flow verification report required by Section 6.2.3.8 of Rule 4311, vent gas flow shall be determined using one or more of the following methods, or by any alternative method approved by the APCO, ARB, and EPA: EPA Methods 1 and 2; a verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 5.13 of Rule 4311; tracer gas dilution or velocity; other flow monitors or process monitors that can provide comparison data on a vent stream that is being directed past the ultrasonic flow meter. [District Rule 4311]

Section 6.4.1 requires the operator of flares that are subject to Section 5.7 to make available to the APCO upon request the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). As discussed above, the enclosed flare is not an open flare; therefore, it is not subject to Section 5.7 and this section does not apply.

Section 6.4.2 requires the operator of flares subject to emission limits in Table 1 and Table 3, Categories A, B, and C shall conduct source testing at least once every 12 months to demonstrate compliance with Section 5.8. The operator shall submit a copy of the testing protocol to the APCO at least 30 days in advance of the scheduled testing. The operator shall submit the source test results not later than 60 days after completion of the source testing. Since the flare is not subject to Section 5.8, source testing to demonstrate compliance with the limits required in that section are not required.

Section 6.5 - Flare Minimization Plan requires the operator of a petroleum refinery flare or any flare at a major source, except landfill operations, that has a flaring capacity of greater than or equal to 5.0 MMBtu per hour shall submit a flare minimization plan (FMP) to the APCO for approval and specifies requirements for operators of flares that are subject to the flare minimization plan provisions of District Rule 4311.

The following condition will be included on the ATC permit:

- Every five years after the initial FMP submittal, the operator shall submit an updated FMP for each flare to the APCO for approval. The current FMP shall remain in effect until the updated FMP is approved by the APCO. If the operator fails to submit an updated FMP as required by this section, the existing FMP shall no longer be considered an approved plan. [District Rule 4311]
- An updated FMP shall be submitted by the operator pursuant to Rule 4311, Section 6.5 addressing new or modified equipment, prior to installing the equipment. Updated FMP submittals are only required if: 1) The equipment change would require an Authority to Construct (ATC) and would impact the emissions from the flare, and 2) The modification is not solely the removal or decommissioning of equipment that is listed in the FMP, and has no associated increase in flare emissions. [District Rule 4311]

Section 6.6 - Vent Gas Composition Monitoring requires that, effective on and after July 1, 2011, the operator of a petroleum refinery flare or any flare at a major source, except landfill operations, that has a flaring capacity equal to or greater than 50 MMBtu per hour shall monitor vent gas composition using one of the five methods pursuant to Section 6.6.1 through Section 6.6.5, as appropriate, and requires that, effective on and after January 1, 2024, the operator of any flare with a flaring capacity equal to or greater than 50 MMBtu per hour, except landfill operations, shall monitor vent gas composition using one of the five methods pursuant to Section 6.6.1 through Section 6.6.5, as appropriate. The flare has a flaring capacity less than 50 MMBtu/hr. Therefore, this section does not apply.

Section 6.7 - Pilot and Purge Gas Monitoring requires that, effective on and after July 1, 2011, the operator of a petroleum refinery flare or any flare at a major source, except landfill operations, that has a flaring capacity equal to or greater than 50 MMBtu per hour shall monitor the volumetric flows of purge and pilot gases with flow measuring devices or other parameters as specified on the Permit to Operate so that volumetric flows of pilot and purge gas may be calculated based on pilot design and the parameters monitored, and requires that, effective on and after January 1, 2024, the operator of any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour shall monitor the volumetric flows of purge and pilot gases with flow measuring devices or other parameters as specified on the Permit to Operate so that volumetric flows of pilot and purge gas may be calculated based on pilot design and the parameters monitored. The flare has a flaring capacity less than 50 MMBtu/hr. Therefore, this section does not apply.

Section 6.8 - Water Seal Monitoring requires that, effective on and after July 1, 2011, the operator of a petroleum refinery flare or any flare at a major source, except landfill operations, that has a flaring capacity equal to or greater than 50 MMBtu per hour with a water seal shall monitor and record the water level and pressure of the water seal that services each flare daily or as specified on the Permit to Operate, and requires that, effective on and after January 1, 2024, the operator of any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour with a water seal shall monitor and record the water level and pressure of the water seal that services each flare daily or as specified on the Permit to Operate. The flare has a flaring capacity less than 50 MMBtu/hr and will not have a water seal. Therefore, this section does not apply.

Section 6.9 - General Monitoring specifies additional monitoring for petroleum refinery flares or any flares at major sources, except landfill operations, that have a flaring capacity equal to or greater than 50 MMBtu per hour, effective on and after July 1, 2011, and additional monitoring for any flares at major sources, except landfill operations, that have a flaring capacity equal to or greater than 50 MMBtu per hour, effective on and after January 1, 2024. The flare has a flaring capacity less than 50 MMBtu/hr. Therefore, this section does not apply.

Section 6.10 - Video Monitoring requires the operator of a petroleum refinery flare to install and maintain equipment that records a real-time digital image of the flare and flame at a frame rate of no less than one frame per minute. The recorded image of the flare shall be of sufficient size, contrast, and resolution to be readily apparent in the overall image or frame. The image shall include an embedded date and time stamp. The equipment shall archive the images for each 24-hour period. In lieu of video monitoring the operator may use an alternative monitoring method that provides data to verify date, time, vent gas flow, and duration of flaring events. The flare is not a petroleum refinery flare. Therefore, this section does not apply.

Section 7.0 - Compliance Schedule specifies the timeframes and dates for compliance with Rule 4311 after loss of exemption, submittal of ATC applications to limit flaring throughput, submittal of ATC applications to modify or replace flares to comply with the emission limits of Rule 4311, and demonstration of compliance with emission limits. The flare will be required to submit an ATC to comply with the applicable requirements of Rule 4311 by the applicable compliance dates; therefore, compliance with Section 7.0 is expected.

The requirements of this rule will be incorporated into the conditions of the ATC permit for the flare. Therefore, compliance with the requirements of District Rule 4311 is expected.

Rule 4701 Internal Combustion Engines – Phase I

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

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engine is subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

Rule 4702 Internal Combustion 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 IC engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

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. The proposed new engine will be required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed; therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the proposed engine.

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 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 and Table 3, as applicable;
- 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 5.11, 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. Pursuant to Section 5.2.2.2.1, engines in the fee payment program shall have actual emissions not greater than the applicable limits in Table 1 during the entire time the engine is part of the fee payment program. This compliance option will sunset after December 31, 2023, where after an operator must comply with the NOx emissions limit requirements in Table 2 and Table 3, per the compliance schedule included in Section 7.5.

Section 5.2.2.3 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 2 and Table 3 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. An operator electing this option shall not be eligible to participate in the fee payment option outlined in Section 5.2.2.2 and Section 5.6.

Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines Rated >50 bhp Used in Non-Agricultural Operations (Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5, Table 7)			
Engine Type	**NO_X Emission Limit (ppmv @ 15% O_2, dry)**	**CO Emission Limit (ppmv @ 15% O_2, dry)**	**VOC Emission Limit (ppmv @ 15% O_2, dry)**
1. a. Rich-Burn, Waste Gas Fueled (≥ 50% total monthly heat input from waste gas based on hhv)	50 ppmv	2,000 ppmv	250 ppmv
1. b. Rich-Burn, Cyclic Loaded, Field Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. c. Rich-Burn, Limited Use	25 ppmv	2,000 ppmv	250 ppmv
1. d. Rich-Burn, Not Listed Above	11 ppmv	2,000 ppmv	250 ppmv
2. a. Lean-Burn, 2-Stroke, Gaseous Fueled, >50 bhp & <100 bhp	75 ppmv	2,000 ppmv	750 ppmv
2. b. Lean-Burn, Limited Use	65 ppmv	2,000 ppmv	750 ppmv
2. c. Lean-Burn Engine used for gas compression	65 ppmv or 93% reduction	2,000 ppmv	750 ppmv
2. d. Waste Gas Fueled (≥ 50% total monthly heat input from waste gas based on hhv)	65 ppmv or 90% reduction	2,000 ppmv	750 ppmv
2. e. Lean-Burn, Not Listed Above	11 ppmv	2,000 ppmv	750 ppmv

Rule 4702, Table 3 Emission Limits/Standards for Spark-Ignited IC Engines Rated >50 bhp Used in Non-Agricultural Operations (Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5, Table 8)			
Engine Type	**NO_X Emission Limit (ppmv @ 15% O_2, dry)**	**CO Emission Limit (ppmv @ 15% O_2, dry)**	**VOC Emission Limit (ppmv @ 15% O_2, dry)**
1. a. Rich-Burn, Waste Gas Fueled (≥ 50% total monthly heat input from waste gas based on hhv)	11 ppmv	2,000 ppmv	90 ppmv
1. b. Rich-Burn, Cyclic Loaded, Field Gas Fueled	11 ppmv	2,000 ppmv	90 ppmv
1. c. Rich-Burn, Limited Use	11 ppmv	2,000 ppmv	90 ppmv
1. d. Rich-Burn, Not Listed Above	11 ppmv	2,000 ppmv	90 ppmv
2. a. Lean-Burn, Limited Use	11 ppmv	2,000 ppmv	90 ppmv
2. b. Lean-Burn Engine used for gas compression	40 ppmv or 93% reduction	2,000 ppmv	90 ppmv
2. c. Waste Gas Fueled (≥ 50% total monthly heat input from waste gas based on hhv)	40 ppmv or 90% reduction	2,000 ppmv	90 ppmv
2. d. Lean-Burn, Not Listed Above	11 ppmv	2,000 ppmv	90 ppmv

The applicant has proposed to install a 1,966 bhp lean burn IC engine that will be fueled with natural gas and digester gas from winery wastewater. Pursuant to District Rule 4702, Section 3.40 Waste Gas is defined as "*an untreated, raw gas derived through a natural process, such as anaerobic digestion, from the decomposition of organic waste at municipal solid waste landfills or publicly owned wastewater treatment facility. Waste gas includes landfill gas which is generated at landfills, digester gas which is generated at sewage treatment facilities, or a combination of the two.*" The digester gas that will be used to fuel the proposed IC engine will not originate from a landfill or publicly owned wastewater treatment facility, and thus does not satisfy the definition of waste gas; therefore, the engine is required to comply with the following emissions limits from Table 2, Row 2.e: 11 ppmvd NO_X, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2). In addition, the engine is required to comply with the following emissions limits from Table 3, Row 2.d: 11 ppmvd NO_X, 2,000 ppmvd CO, and 90 ppmvd VOC (all measured @ 15% O_2) by the compliance dates specified in Section 7.5.

The following previously presented condition will be included on the proposed ATC permit for the proposed IC engine:

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.049 g-NOx/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.050 g-NOx/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 4.1 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.032 g-PM10/bhp-hr when fueled with natural gas, and 0.05 g-PM10/bhp-hr when fueled with digester gas or a natural gas/digester gas blend; 0.14 g-CO/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.14 g-CO/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 19.5 ppmvd CO @ 15%); and 0.049 g-VOC/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.050 g-NOx/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 12.0 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201, 4102, and 4702, and 40 CFR 60.4233]

Section 5.2.3.1 requires that the operator of a spark-ignited internal combustion engine rated > 50 bhp that is used exclusively in agricultural operations shall not operate it in such a manner that results in emissions exceeding the limits in Table 3 of Rule 4702 for the appropriate engine type on an engine-by-engine basis.

Section 5.2.3.2 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 3 on an engine-by-engine basis, an operator of a spark-ignited agricultural IC engine may elect to implement an alternative emission control plan pursuant to Section 8.0.

Section 5.2.3.3 requires an operator of an agricultural IC engine in that is subject to the applicable requirements of Table 3 shall not replace such engine with an engine that emits more emissions of NOx, VOC, and CO, on a ppmv basis, (corrected to 15% oxygen on a dry basis) than the engine being replaced.

The proposed natural gas/digester gas-fired IC engine is a non-agricultural engine; therefore, Section 5.2.3 does not apply to the proposed engine.

Section 5.2.4 requires the operator of a certified compression-ignited engine rated >50 bhp shall comply with the following requirements of Sections 5.2.4.1, 5.2.4.2, 5.2.4.3, 5.2.4.3, and 5.2.4.4. The proposed natural gas/digester gas-fired engine is not a compression-ignited engine; therefore, Section 5.2.4 does not apply to the proposed engine.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The IC engine proposed under this project will not have CEMS installed; therefore, this section of the rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the NO_X emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engine evaluated under this project; therefore, this section of the rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the NO_X emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engine evaluated under this project; therefore, this section of the rule is not applicable.

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 applicant has proposed that the engine comply with the applicable emission limits of Table 2 and Table 3 of District Rule 4702; therefore, payment of annual emissions fees for the engine is not required and this section of the rule is not applicable.

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 shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

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 SO_2 emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

The proposed IC engine will be fueled with PUC regulated natural gas and digester gas. To satisfy BACT, the average sulfur content of the digester gas fuel for the engine will be limited to 40 ppmv (approximately equal to 2.4 grains sulfur per 100 standard cubic feet). The following conditions will be included on the ATC permit for the proposed IC engine:

- This engine shall only be fueled with PUC-regulated natural gas, digester gas, or a blend of PUC-regulated natural gas and digester gas. [District Rules 2201, 4702, and 4801]
- The sulfur content of the digester gas and natural gas/digester gas blends used as fuel in this engine shall not exceed 40 ppmv as H2S. An averaging period of up to one calendar day in length may be utilized for demonstration of compliance with the digester gas sulfur content limit. [District Rules 2201, 4702, and 4801]

Section 5.8 requires that on and after the compliance schedule specified in Section 5.2.4 and 7.0, operators of engines subject to this rule shall limit emissions of particulate matter through compliance with the following applicable requirements of Sections 5.8.1 – 5.8.2:

5.8.1 Spark-ignited engines shall comply with the requirements of Section 5.7.
5.8.2 Compression-ignited engines shall comply with the applicable CARB/EPA Tier certification standard per Table 6.

The proposed spark-ignited IC engine will be required to comply with Section 5.7, which satisfies compliance with this section.

Section 5.9 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 5.9.1 – 5.9.11:

Section 5.9.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp 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:

- 5.9.1.1 Periodic NO_X and CO emission concentrations,
- 5.9.1.2 Engine exhaust oxygen concentration,
- 5.9.1.3 Air-to-fuel ratio,
- 5.9.1.4 Flow rate of reducing agents added to engine exhaust,
- 5.9.1.5 Catalyst inlet and exhaust temperature,
- 5.9.1.6 Catalyst inlet and exhaust oxygen concentration, or
- 5.9.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic monitoring of NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. In addition, as discussed later in this evaluation, the proposed natural gas/digester gas-fired IC engine is also subject to 40 CFR 64 – Compliance Assurance Monitoring (CAM) for NO_X emissions, which requires daily monitoring of parameters to ensure compliance with the NO_X emission limit of the permit. Therefore, daily monitoring of NO_X and O_2 concentrations and, as proposed by the applicant, monthly monitoring of CO and O_2 concentrations in accordance with pre-approved alternate monitoring plan “A” within District Policy SSP 1810 will be required. .

Therefore, the following conditions will be included on the ATC permit for the proposed IC engine:

- Coincident with the end of the commissioning period, the permittee shall monitor and record the stack concentration of NOx and O2 at least once every day (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702, and 40 CFR 64]
- The permittee shall monitor and record the stack concentration of CO and O2 at least once every calendar month (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District

specifications required for portable analyzers. 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. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.9.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.9.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The proposed engine will be subject to Section 5.9.1; therefore, this section is not applicable.

Section 5.9.3 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 ATC permit for the engine includes a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.9.4 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 IC engine proposed under this project will not have CEMS installed; therefore, this section of the rule is not applicable.

Section 5.9.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.9 approved by the APCO. As stated above, the proposed ATC permit for the engine includes an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.9.6 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 engine in this project. Therefore, the following condition will be included on the ATC permit for the proposed IC engine:

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

Section 5.9.7 requires that for each engine, the permittee 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 5.9.8 requires that for each engine, 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 the section that covers Section 6.5 of this rule.

Section 5.9.9 requires for each non-agricultural spark-ignited IC engine, use of a portable NO_X analyzer to take NO_X 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. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NO_X 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 NO_X emissions readings shall be reported to the APCO in a manner approved by the APCO. NO_X 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.

The following conditions will be included on the ATC permit for the proposed IC engine to ensure compliance:

- Coincident with the end of the commissioning period, the permittee shall monitor and record the stack concentration of NOx and O2 at least once every day (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702, and 40 CFR 64]
- The permittee shall monitor and record the stack concentration of CO and O2 at least once every calendar month (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. 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. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- In-stack emission monitors shall be calibrated using EPA protocol calibration gases a minimum of once within every 30 days. Records of calibration dates, instruments calibrated, gas readings prior to calibration, calibration gases used, and calibration gas certification and expiration dates shall be maintained. [District Rules 1080 and 4702, and 40 CFR 64]
- Portable emission monitors shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the

APCO. Calibration records shall be shall be maintained. [District Rules 1080 and 4702, and 40 CFR 64]

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- 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 and any in-stack emission monitors 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 5.9.10 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 proposed ATC permit for the engine includes a pre-approved alternate emissions monitoring plan that requires periodic NO_X, CO, and O_2 emissions concentrations. Therefore, this section is satisfied.

Section 5.9.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. In lieu of installing a nonresettable fuel meter, the operator may use an alternative device, method, or technique in determining daily fuel consumption provided that the alternative is approved by the APCO. The operator shall maintain, operate, and calibrate the required fuel meter in accordance with the manufacturer’s instructions. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engine evaluated under this project; therefore, this section of the rule is not applicable.

Section 5.10 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.9. The proposed spark-ignited non-agricultural IC engine is subject to the requirements of Section 5.9; therefore, this section of the rule is not applicable.

Section 5.11 specifies SO_X 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:

5.11.1 An operator of an engine complying with Sections 5.7.2, 5.7.5, 5.7.7 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,

5.11.2 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

5.11.3 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.

The following condition will be included on the ATC permit for the proposed IC engine:

- Fuel sulfur content analysis of the digester gas used to fuel this engine shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate, or an alternative method approved by EPA and the District. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.12 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 spark-ignited non-agricultural engine is required to have a District Permit to Operate; therefore, this section of the rule is not applicable.

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 emission control plan shall contain the following information, as applicable for each engine:

6.1.1.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
6.1.1.2 Engine manufacturer,
6.1.1.3 Model designation and engine serial number,
6.1.1.4 Rated brake horsepower,
6.1.1.5 Type of fuel and type of ignition,
6.1.1.6 Combustion type: rich-burn or lean-burn,
6.1.1.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
6.1.1.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
6.1.1.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
6.1.1.10 Type of control to be applied, including in-stack monitoring specifications,
6.1.1.11 Applicable emission limits,
6.1.1.12 Documentation showing existing emissions of NO_X, VOC, and CO, and
6.1.1.13 Date that the engine will be in full compliance with this rule.

Section 6.1.2 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 engine is in compliance with the emission requirements of this rule.

Section 6.1.3 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 IC engine evaluated under this project.

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 log 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.

The following condition will be included on the ATC permit for the proposed IC engine:

- 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 hours of operation for commissioning of the engine, the total hours of operation, the type and quantity of each fuel used, 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, 4701, and 4702, and 40 CFR 60.4243 and 40 CFR 60.4245]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.9 and Section 5.10 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following previously presented condition will be included on the ATC permit for the proposed IC engine:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 2201 and 4702 and 40 CFR 60.4245]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and provided to the APCO upon request. The records shall include, but are not limited to, the following:

6.2.3.1 Total hours of operation,
6.2.3.2 The type of fuel used,
6.2.3.3 The purpose for operating the engine,
6.2.3.4 For emergency standby engines, all hours of non-emergency and emergency operation shall be reported, and
6.2.3.5 Other support documentation necessary to demonstrate claim to the exemption

The applicant is not claiming an exemption for the proposed engine under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.0, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that all spark-ignited engines and compression-ignited engines that have been retro-fitted with a NOx exhaust control, except certified spark-ignited engines, those certified per Section 9.0, and certified compression-ignited engines, shall comply with Sections 6.3.2 through 6.3.4.

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 NOx 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.

As discussed above, the proposed IC engine is also subject to 40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. 40 CFR 60, Subpart JJJJ requires that a performance test be conducted for uncertified engines rated 500 bhp or more every 8,760 hours of operation or every 3 years, whatever comes first.

The following conditions will be included on the ATC permit for the proposed IC engine:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days of initial start-up. [District Rules 1081, 2201, and 4702, and 40 CFR 60.4243]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 8,760 hours of operation or 24 months, whichever comes first. [District Rules 1081, 2201, and 4702 and 40 CFR 60.4243]

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.

As discussed above, the proposed IC engine is also subject to the testing requirements of 40 CFR 60, Subpart JJJJ.

The following conditions will be included on the ATC permit for the proposed IC engine:

- 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 and 40 CFR 60.4244]
- For emissions source testing, the arithmetic average of three 60-consecutive-minute test runs shall apply. Each test run shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. 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 (however, VOC may also be reported as propane only for demonstration of compliance with the VOC limits in 40 CFR 60 Subpart JJJJ). NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rule 4702 and 40 CFR 60.4244]

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 shall 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 engine will be fueled with both natural gas and digester gas; 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 engine; 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 (H_2S) 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:

% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$

Where:

$C_{SO2,\ inlet}$ = concentration of SO_X (expressed as SO_2) at the inlet side of the SO_X emission control system, in lb/Dscf

$C_{SO2,\ outlet}$ = concentration of SO_X (expressed as SO_2) 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.

The following conditions will be included on the ATC permit for the IC engine:

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E; CO (ppmv) - EPA Method 10; VOC (ppmv) - EPA Method 18, or 25A or 25B; stack gas oxygen - EPA Method 3 or 3A; stack gas velocity/volumetric flowrate - 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 EPA and the District may be used to address the source testing requirements of this permit. [District Rules 1081, 2201, and 4702]
- 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 EPA and the District. [District Rules 2201 and 4702]
- Fuel sulfur content analysis of the digester gas used to fuel this engine shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate, or an alternative method approved by EPA and the District. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [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 5.9. 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 requirements of Section 6.5.2 through Section 6.5.9 shall apply to all engines, except certified spark-ignited engines, those certified per Section 9.0, and certified compression-ignited engines.

The natural gas/digester gas-fired IC engine evaluated under this project is not a certified IC engine and has not been certified per Section 9.0. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engine.

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.

To comply with the requirements of Sections 6.5.2 and 6.5.3 of the rule, the applicant has proposed to perform the monitoring required by the alternate monitoring program at least on a monthly basis. Therefore, the following previously proposed condition will be included on the proposed ATC permit for the IC engine:

- Coincident with the end of the commissioning period, the permittee shall monitor and record the stack concentration of NOx and O2 at least once every day (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702, and 40 CFR 64]
- The permittee shall monitor and record the stack concentration of CO and O2 at least once every calendar month (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. 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. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

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.

The applicant has proposed that the alternate monitoring program will ensure compliance with these two sections of the rule. Therefore, the following condition will be included on the ATC permit for the proposed IC engine:

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer, the District-approved in-stack emission monitor(s), or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), 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(s) 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, and 40 CFR 64]

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 engine will be operated and maintained per the specifications of the manufacturer or emissions control system supplier. Therefore, the following conditions will be included on the ATC permit for the proposed IC engine:

- 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]
- This engine shall be operated within the ranges that the source testing has shown result in pollution emission rates within the emissions limits as specified on this permit. [District Rules 2201 and 4702]

Section 6.5.7 requires procedures and a schedule for using a portable emissions analyzer to take NO_X and CO emission readings pursuant to Section 5.9.9. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the rule.

The following previously proposed condition will be included on the ATC permit for the proposed IC engine:

- 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 and any in-stack emission monitors 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 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 5.9.1 and 5.9.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the rule.

The following condition will be included on the ATC permit for the proposed IC engine:

- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of portable emission analyzer(s) and in-stack emission analyzer(s), (4) emission 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, and 40 CFR 64]

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 included on the ATC permit for the proposed IC engine to ensure compliance:

- 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 (AECP) option of Section 8.0. The proposed IC engine 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 (AECP) to comply with the NO_X emission requirements of Section 5.2 for a group of engines. Requirements for use of an AECP include: only engines subject to Section 5.2 are eligible for inclusion in an AECP; during any seven consecutive day period, the operator shall operate all engines in the AECP to achieve an actual aggregate NO_X emission level that is ≤ 90% of the NO_X emissions that would be obtained by controlling the engines to comply individually with the NO_X limits in Section 5.2; the operator shall establish a NO_X emission factor limit for each engine; the operator must submit the AECP at least 18 months before compliance with the emission limits in Section 5.2 is required and receive approval from the APCO; the operator must submit and updated or modified AECP for approval by the APCO prior to any modifications; and the operator must maintain records necessary to demonstrate compliance with AECP.

The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engine evaluated under this project; 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 IC engine under this project is not currently being proposed and, in addition, certification under this section of the rule would require that the engine or identical units with the same fuel supply and exhaust control systems were operating and could be source tested to demonstrate compliance with the applicable limits; therefore, this section of the rule is not applicable.

Conclusion

As shown above, the applicable requirements of Rule 4702 will be incorporated into the ATC permit for the proposed non-agricultural, natural gas/digester gas-fired, lean burn, IC engine and it is expected to comply with the applicable requirements of Rule 4702 upon initial operation.

Rule 4801 Sulfur Compounds

The purpose of District Rule 4801 is to limit the emissions of sulfur compounds. A maximum concentration and test method are specified. The provisions of this rule shall apply to any discharge to the atmosphere of sulfur compounds, which would exist as a liquid or a gas at standard conditions.

Section 3.1 states 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: two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO_2), on a dry basis averaged over 15 consecutive minutes.

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

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

Where:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi

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

Estimated F Factor for Natural Gas: 8,578 dscf/MMBtu at 60 ˚F
Estimated F Factor for the Digester Gas: 8,784 dscf/MMBtu at 60 ˚F

ATC N-1237-661 (Digester with Enclosed Flare)

To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from the flare will be calculated based on the sulfur content for the digester gas combusted in the flare: 0.0113 lb-SO_X/MMBtu (based on a maximum digester gas sulfur content of 50 ppmv as H_2S).

$$\frac{0.009\, lb - SOx}{MMBtu} \times \frac{1\, MMBtu}{8{,}784\, dscf} \times \frac{1\, lb \cdot mol}{64\, lb - SOx} \times \frac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot {}^{\circ}R} \times \frac{520\, {}^{\circ}R}{14.7\, psi} \times \frac{1{,}000{,}000\, parts}{million} = 6.1\, \frac{parts}{million}$$

Because 6.1 ppmv is ≤ 2000 ppmv, the flare is expected to comply with Rule 4801. The following condition will be included on the ATC permit to ensure compliance:

- The H2S content of the scrubbed biogas shall not exceed 40 ppmv. [District Rules 2201 and 4801]

ATC N-1237-892 (1,966 bhp Natural Gas/Digester Gas-Fired IC Engine)

To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum concentration of sulfur compound emissions from the engine will be calculated below based on the engine being fueled with PUC regulated natural gas and digester gas:

SO_X Emission Concentration from Engine When Fueled with Natural Gas

$$\frac{0.00285\, lb - SOx}{MMBtu} \times \frac{1\, MMBtu}{8{,}578\, dscf} \times \frac{1\, lb \cdot mol}{64\, lb - SOx} \times \frac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot {}^{\circ}R} \times \frac{520\, {}^{\circ}R}{14.7\, psi} \times \frac{1{,}000{,}000\, parts}{million} = 2.0\, \frac{parts}{million}$$

SO_X Emission Concentration from Engine When Fueled with Digester Gas

$$\frac{0.0090\, lb - SOx}{MMBtu} \times \frac{1\, MMBtu}{8{,}784\, dscf} \times \frac{1\, lb \cdot mol}{64\, lb - SOx} \times \frac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot {}^{\circ}R} \times \frac{520\, {}^{\circ}R}{14.7\, psi} \times \frac{1{,}000{,}000\, parts}{million} = 6.1\, \frac{parts}{million}$$

Because 2.0 ppmv and 6.1 ppmv are ≤ 2000 ppmv, the engine is expected to comply with Rule 4801.

The following conditions will be placed on the ATC permit to ensure compliance:

- This engine shall only be fueled with PUC-regulated natural gas, digester gas, or a blend of PUC-regulated natural gas and digester gas. [District Rules 2201, 4702, and 4801]
- The sulfur content of the digester gas and natural gas/digester gas blends used as fuel in this engine shall not exceed 40 ppmv as H2S. An averaging period of up to one calendar day in length may be utilized for demonstration of compliance with the digester gas sulfur content limit. [District Rules 2201, 4702, and 4801]

40 CFR 64 – Compliance Assurance Monitoring (CAM)

40 CFR Section 64.2, Applicability, states that except for back-up utility units that are exempt under paragraph (b)(2), the requirements of this subpart shall apply to a pollutant-specific emissions unit at a major source that is required to obtain a Part 70 or 71 permit if the unit satisfies all of the following criteria:

1) The unit must have an emission limit for the pollutant;
2) The unit must have add-on controls for the pollutant; these are devices such as flue gas recirculation (FGR), baghouses, catalytic oxidizers, etc; and
3) The unit must have a pre-control potential to emit of greater than the major source thresholds.

Pollutant	Major Source Threshold (lb/year)
NO_X	20,000
SO_X	140,000
PM_{10}	140,000
CO	200,000
VOC	20,000

<u>ATC N-1237-661 (Digester with Enclosed Flare)</u>

The permit for the wastewater digester includes emission limits for NO_X, SO_X, PM_{10}, CO, and VOC from the combustion of digester gas in the flare. The digester gas generated in this wastewater digester is typically combusted in one of two IC engines operated at this facility. However, if either of the IC engines are not operational, the flare is used as a backup combustion device to prevent digester gas (a highly explosive/flammable gas) from being emitted directly to the atmosphere. The digester gas can contain small amounts of VOCs. Therefore, it will conservatively be assumed that the flare is a control device for VOC emissions from the digester. The flare is not considered a control device for NO_X, SO_X, PM_{10}, or CO emissions. Therefore, the CAM requirements of 40 CFR 64 are not applicable for these pollutants.

Pursuant to the draft AP-42 Table 2.4-3 (10/08), flares have an expected control efficiency of 97.9%. Controlled VOC emissions are 123 lb/yr. Therefore, the uncontrolled potential VOC emissions from the digester are calculated as follows:

Pre-Control VOC from Digester

123 lb-VOC/yr ÷ (1 – 0.977) = 5,516 lb-VOC/yr

As shown above, the pre-control potential to emit for VOC from this permit unit does not exceed the applicable major source threshold for this pollutant. Therefore, this permit unit is not subject to CAM for VOC.

ATC N-1237-892-0 (Natural Gas/Digester Gas-Fired IC Engine)

The permit for proposed IC engine includes emission limits for NO_X, SO_X, PM_{10}, CO, and VOC emissions. The IC engine will be equipped with a Selective Catalytic Reduction (SCR) system to control NO_X emissions and will utilize an oxidation catalyst to control CO and VOC emissions. Therefore, the IC engine is potentially subject to CAM for NO_X, CO, and VOC. This proposed IC engine will not be equipped with any add-on controls for SO_X or PM_{10}; therefore, CAM is not required for SO_X or PM_{10}.

The annual pre-control potential to emit for NO_X, CO, and VOC from this permit unit is calculated below using the uncontrolled emission factors provided by the engine manufacturer.

Pre-Control NO_X from the IC Engine

Engine Rating: 1,966 bhp
Max Annual Hours of Operation: 8,400 hours per year
Engine Manufacturer's pre-control NO_X emission factor: 0.6 g-NO_X/bhp-hr

1,966 bhp x 0.6 g-NO_X/bhp-hr x 8,400 hr/yr ÷ 453.59 g/lb = 21,845 lb-NO_X/yr

Pre-Control CO from the IC Engine

Engine Manufacturer's pre-control CO emission factor: 2.3 g-CO/bhp-hr

1,966 bhp x 2.3 g-CO/bhp-hr x 8,400 hr/yr ÷ 453.59 g/lb = 83,739 lb-CO/yr

Pre-Control VOC from the IC Engine

Engine Manufacturer's pre-control VOC emission factor: 0.33 g-VOC/bhp-hr

1,966 bhp x 0.33 g-VOC/bhp-hr x 8,400 hr/yr ÷ 453.59 g/lb = 12,015 lb-VOC/yr

As shown above, the pre-control potential to emit for NO_X from this permit unit exceeds the applicable major source threshold for this pollutant. Therefore, this permit unit is subject to CAM for NO_X. As shown above, the pre-control potential to emit for CO and VOC from this permit unit do not exceed the applicable major source thresholds for these pollutants. Therefore, this permit unit is not subject to CAM for CO or VOC. The applicable CAM requirements for NO_X from this permit unit are discussed below.

§64.3 - Monitoring Design Criteria

This section specifies the design criteria for the CAM method. Paragraph (a) (General criteria) requires that the CAM method be designed to obtain data for one or more appropriate indicators of emission control system performance and requires the owner to establish appropriate ranges or designated conditions for the selected indicators such that operation within the ranges provides a reasonable assurance of ongoing compliance with emission limitations or standards for the anticipated range of operating conditions.

As discussed above, NO_X emissions from the IC engine are controlled by an SCR system. An SCR system operates as an external control device where exhaust gases and a reagent, urea or ammonia, are passed through an appropriate catalyst. The reagent will be injected upstream of the catalyst where it will react and reduce NO_X over the catalyst bed to form elemental nitrogen and water vapor.

The post-project potential to emit for NO_X from the engine is below the major source threshold for NO_X. Therefore, monitoring of parameters to ensure compliance with the NO_X emission limit once per day will satisfy the CAM requirement for monitoring frequency. The facility has chosen to satisfy CAM requirements by performing daily monitoring of NO_X emission concentrations utilizing a portable analyzer or an in-stack exhaust analyzer. The portable analyzer or in-stack exhaust analyzer will take NO_X and O_2 measurements at least once each day that the engine operates.

The following condition will be included on the ATC permit for the IC engine to ensure compliance with this section:

- Coincident with the end of the commissioning period, the permittee shall monitor and record the stack concentration of NOx and O2 at least once every day (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702, and 40 CFR 64]

Paragraph (b) (*Performance criteria)* requires the owner or operator to establish and maintain the following:

(1) Specifications to ensure that representative data are collected

The applicant has proposed to perform daily monitoring utilizing a portable analyzer specifications or an in-stack emission monitor and to perform daily recordkeeping. Therefore, sufficient data will be collected for the engine to ensure it is operating in compliance to justify the once daily readings as representative normal operating conditions.

(2) Verification procedures for startup of new monitoring equipment
(3) Quality assurance and control practices to ensure continuing validity of data

Periodic NO_X source testing will be required at least once every 8,760 hours of operation or 24 months, whichever comes first, and monitoring of the NH_3 slip will be required at least once per month. These periodic direct emission measurements ensure that the engine and the SCR system are operating properly. In addition, the engine will be maintained and operated in accordance with the manufacturer's recommendations.

In addition, the following conditions will be included on the permit for the IC engine:

- In-stack emission monitors shall be calibrated using EPA protocol calibration gases a minimum of once within every 30 days. Records of calibration dates, instruments calibrated, gas readings prior to calibration, calibration gases used, and calibration gas certification and expiration dates shall be maintained. [District Rules 1080 and 4702, and 40 CFR 64]
- Portable emission monitors shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Calibration records shall be shall be maintained. [District Rules 1080 and 4702, and 40 CFR 64]
- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer, the District-approved in-stack emission monitor(s), or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), 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(s) 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, and 40 CFR 64]

(4) Data collection frequency and procedures

The facility will be required to measure and record the NO_X and O_2 readings from the engine at least once daily. These records shall be maintained by the facility and shall be made available upon request.

Paragraph (c) (Evaluation factors) requires the owner or operator to take into account site specific factors in the design of the CAM system.

(c) Evaluation factors. In designing monitoring to meet the requirements of this section, the owner or operator shall take into account site-specific factors including the applicability of existing monitoring equipment and procedures, the ability of the monitoring to account for process and control device operational variability, the reliability and latitude built into the control technology, and the level of actual emissions relative to the compliance limitation.

No additional site specific information will need to be accounted for in the design of the proposed CAM system.

(d) Special criteria for the use of continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS) or predictive emission monitoring system (PEMS)

A CEMS, COMS, or PEMS is not necessary or required for the subject emission unit. Therefore, the requirements of this section are not applicable.

§64.4 - Submittal Requirements

This section specifies submittal requirements for the owner or operator which ensure the CAM system will comply with the design criteria of §64.3. The facility has submitted a complete CAM system proposal that specifies the parameters to be monitored in accordance with §64.3 above. Therefore, the facility has satisfied the requirements of the submittal requirements of this section.

§64.5 - Deadlines for Submittals

This section specifies required timing for submittals required under §64.4.

Large pollutant-specific emissions units (those with controlled emissions exceeding major source thresholds) are required to make the submittals as a part of the initial Title V permit application where the application has either not been filed or has not been deemed complete. Where the initial Title V permit has been issued without implementation of 40 CFR 64, the owner or operator must make the required submittals as a part of a subsequent application for any significant permit revision. If the required information is not submitted by either of these deadlines, it must be submitted as a part of the application for the Title V permit renewal.

For other pollutant-specific emissions units, the required submittal deadline is the application for Title V permit renewal. The applicant has submitted their CAM proposal with this significant permit revision. Therefore, the applicant has satisfied the submittal deadline requirements of this section.

§64.6 - Approval of Monitoring

This section stipulates the following:

- A requirement that the permitting authority act to approve the proposed monitoring by confirming that the monitoring submitted complies with the requirements of §64.3.
- An allowance for the permitting authority to condition the approval based on collecting additional data on the indicators to be monitored, including performance or compliance testing.
- The minimum conditions that must be placed on the permit in the event that the proposed monitoring is approved by the permitting authority including a milestone schedule for completion of any conditional approval actions required by the owner or operator, such as installations, testing, or verification of operational status.

- Actions required by the permitting authority in the event that the proposed monitoring is not approved.

The CAM submittal requirements and stipulations for approval of such submittals pursuant to §64.4, §64.5, and §64.6 have been completed in conjunction with the application and review process for this application. Therefore, the facility is in compliance with the requirements of this section.

<u>§64.7 - Operation of Approved Monitoring</u>

This section stipulates the following:

- Requirements that the owner or operator 1) commence the monitoring upon receipt of a Title V permit that includes such monitoring, 2) properly maintain the monitoring system, and 3) conduct all monitoring in a continuous mode with the exception of outage periods associated with monitor malfunction and repair and with quality assurance and control activities.
- Actions required by the owner or operator in response to excursions or exceedances.
- A requirement for the owner or operator to document any need for improved monitoring based upon either an identification of a failure of the monitoring system to identify an excursion or exceedance or upon the results of compliance or performance testing that identifies a need to modify the monitoring.

The following condition will be included on the ATC permit for the IC engine:

- The permittee shall comply with the compliance assurance monitoring operation and maintenance requirements of 40 CFR Part 64.7. [40 CFR 64]

<u>§64.8 - Quality Improvement Plan (QIP) Requirements</u>

This section stipulates that the Administrator or the permitting authority may require that the facility develop and implement a QIP in the event of a determination of a need for improved monitoring pursuant to §64.7. §64.8 also identifies the minimum elements required in the QIP, and requires that the facility implement the QIP as expeditiously as possible, with implementation not exceeding 180 days after the date that the need for implementation was identified unless the permitting authority is notified.

The following condition will be included on the permit for the IC engine:

- If the District or EPA determine that a Quality Improvement Plan is required under 40 CFR 64.7(d)(2), the permittee shall develop and implement the Quality Improvement Plan in accordance with 40 CFR 64.8. [40 CFR 64.8]

<u>§64.9 - Reporting and Recordkeeping Requirements</u>

This section stipulates the minimum reporting and recordkeeping requirements for facilities subject to 40 CFR 64.

The following conditions will be included on the ATC permit for the IC engine:

- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of portable emission analyzer(s) and in-stack emission analyzer(s), (4) emission 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, and 40 CFR 64]
- The permittee shall comply with the record keeping and reporting requirements of 40 CFR part 64.9. [40 CFR Part 64.9]

§64.10 - Savings Provisions

This section states that the purpose of 40 CFR 64 is to require, as a part of the issuance of a Title V permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of 40 CFR 64. In addition, §64.10 states that nothing in 40 CFR 64 shall excuse an owner or operator from any other requirements of federal, state or local law or restrict or abrogate the authority of the Administrator or of the permitting authority.

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

It is determined that no other agency has prepared or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The proposed project involves the combustion of wastewater digester gas in either the existing flare or the proposed IC engine. Combustion of the digester gas will oxidize the methane in the gas to carbon dioxide and water vapor. Because methane has a global warming potential more than 21 times that of carbon dioxide, combustion of the methane from the digester will result in a large net decrease in the global warming potential emitted from the wastewater when compared to levels from uncovered wastewater lagoons. Therefore, the project will not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that this portion of the project would have a less than cumulatively significant impact on global climate change.

Additionally, the project contains natural gas-fired combustion devices. On December 17, 2009, the District's Governing Board adopted a policy, APR 2005, *Addressing GHG Emission Impacts for Stationary Source Projects Under CEQA When Serving as the Lead Agency,* for addressing GHG emission impacts when the District is Lead Agency under CEQA and approved the District's guidance document for use by other agencies when addressing GHG impacts as lead agencies under CEQA. Under this policy, the District's determination of significance of project-specific GHG emissions is founded on the principal that projects with GHG emission reductions consistent with AB 32 emission reduction targets are considered to have a less than significant impact on global climate change. Consistent with District Policy 2005, projects complying with an approved GHG emission reduction plan or GHG mitigation program, which avoids or substantially reduces GHG emissions within the geographic area in which the project is located, would be determined to have a less than significant individual and cumulative impact for GHG emission.

The California Air Resources Board (ARB) adopted a Cap-and-Trade regulation as part one of the strategies identified for AB 32. This Cap-and-Trade regulation is a statewide plan, supported by a CEQA compliant environmental review document, aimed at reducing or mitigating GHG emissions from targeted industries. Facilities subject to the Cap-and-Trade regulation are subject to an industry-wide cap on overall GHG emissions. Any growth in emissions must be accounted for under that cap such that a corresponding and equivalent reduction in emissions must occur to allow any increase. Further, the cap decreases over time, resulting in an overall decrease in GHG emissions.

Under District policy APR 2025, *CEQA Determinations of Significance for Projects Subject to ARB's GHG Cap-and-Trade Regulation*, the District finds that the Cap-and-Trade is a regulation plan approved by ARB, consistent with AB32 emission reduction targets, and supported by a CEQA compliant environmental review document. As such, consistent with District Policy 2005, projects complying with Cap-and-Trade requirements are determined to have a less than significant individual and cumulative impact for GHG emissions.

The GHG emissions increases associated with the IC engines in this project result from the combustion of fossil fuel, other than jet fuel, delivered from suppliers subject to the Cap-and-Trade regulation. Therefore, as discussed above, consistent with District Policies APR 2005 and APR 2025, the District concludes that the GHG emissions increases associated with the IC engine in this project would also have a less than significant individual and cumulative impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that the potential project emissions are equal to or less than 2 lbs per day per pollutant, and therefore considerably below all annual criteria emissions CEQA significant thresholds. The activity will occur at an existing facility and involves negligible expansion of the existing use. Furthermore, the District determined that the activity will not have a significant effect on the environment. Therefore, the District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

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 N-1237-661-5 and -892-0 subject to the permit conditions on the attached draft ATCs in Appendix B.

X. Billing Information

Annual Permit Fees			
Permit Number	**Fee Schedule**	**Fee Description**	**Annual Fee**
N-1237-661-5	3020-02-H	39.4 MMBtu/hr Flare	$1,238
N-1237-892-0	3020-10-F	1,966 bhp IC Engine	$900

Appendices

A: Current Permit N-1237-661-3
B: Draft ATCs N-1237-661-5 and -892-0
C: Analysis of Digester Gas at the Facility
D: Data Sheet for Proposed IC Engine
E: Quarterly Net Emissions Change
F: BACT Analysis for IC Engine when Fueled with Natural Gas
G: BACT Guideline and BACT Analysis for IC Engine when Fueled with Digester Gas
H: ERC Surplus Analyses
I: ERC Withdrawal Calculations
J: Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) Memo
K: E & J Gallo Winery Compliance Certification
L: Facility NOx, SOx, PM10 and CO Emission Summaries and Calculations

APPENDIX A

Current Permit N-1237-661-3

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: N-1237-661-3 **EXPIRATION DATE:** 09/30/2021

EQUIPMENT DESCRIPTION:
DIGESTER GAS OPERATION COMPOSED OF A WASTE WATER TREATMENT SYSTEM WITH AN EQUALIZATION TANK, HIGH RATE ANAEROBIC DIGESTER, TWO LOW RATE ANAEROBIC DIGESTERS, AND MEMBRANE BIOLOGICAL REACTOR SYSTEM CONSISTING OF AN ANOXIC TANK, A PRE-AERATION TANK, AND TWO MEMBRANE BIOLOGICAL REACTORS WITH BIOGAS SENT TO ONE BIOLOGICAL SCRUBBER, TWO ACTIVATED CARBON FILTERS, THE DIGESTER GAS WILL BE ROUTED TO TWO IC ENGINES (PERMITS N-1237-605 AND '606), OR TO A 600 CFM (EQUIVALENT TO 32.4 MMBTU/HR) OVIVO GWE ENCLOSED EMERGENCY FLARE

PERMIT UNIT REQUIREMENTS

1. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
2. Visible emissions from the flare serving the anaerobic digesters shall not equal or exceed Ringelmann 1/4 or 5% opacity for a period or periods aggregating more than three minutes in any one hour. [District Rules 2201 and 4101] Federally Enforceable Through Title V Permit
3. 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]
4. The anaerobic digester system and its associated piping shall be maintained leak free. [District Rule 2201] Federally Enforceable Through Title V Permit
5. This flare shall only be fired on biogas collected from the anaerobic digester system. [District Rule 2201] Federally Enforceable Through Title V Permit
6. The flare shall be operated only for maintenance, testing, required regulatory purposes, and during periods where both engines, permits N-1237-605 and N-1237-606, cannot be operated due to an emergency, as defined in this permit. Operation of the flare for maintenance, testing, and required regulatory purposes shall not exceed 200 hours per year. [District Rule 2201 and 4311] Federally Enforceable Through Title V Permit
7. An emergency is defined as any situation or a condition arising from a sudden and reasonably unforeseeable and unpreventable event beyond the control of the operator. Examples include, but are not unlimited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility. A flaring event due to improperly designed equipment, lack of preventative maintenance, careless or improper operation, operator error, or willful misconduct does not qualify as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered as an emergency. [District Rules 2201 and 4311] Federally Enforceable Through Title V Permit
8. Emissions from the flare shall not exceed any of the following limits: 0.06 lb-NOx/MMBtu (as NO2); 0.008 lb-PM10/MMBtu; 0.75 lb-CO/MMBtu; or 0.019 lb-VOC/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit
9. The sulfur content of the biogas being incinerated by the flare shall not exceed 40 ppmv (as H2S). [District Rule 2201] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

10. The sulfur content of the digester gas combusted in this flare shall be monitored and recorded weekly. After eight (8) consecutive weekly tests show compliance, the digester gas sulfur content monitoring frequency may be reduced to once every calendar quarter. If quarterly monitoring shows a violation of the digester gas sulfur content limit of this permit, then weekly monitoring shall resume and continue until eight consecutive weeks of monitoring show compliance with the gas sulfur content limit. Once compliance with the gas sulfur content limit is shown for eight consecutive weeks, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas shall not be required if the flare does not operate during that period. Records of the results of monitoring of the digester gas sulfur content shall be maintained. [District Rule 2201] Federally Enforceable Through Title V Permit

11. Monitoring of the digester gas sulfur content shall be performed using a Testo 350 XL portable emission monitor; District-approved in-line H2S monitors; gas detection tubes calibrated for H2S; District-approved source test methods, including EPA Method 11 or EPA Method 15, ASTM Method D1072, D4084, and D5504; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201] Federally Enforceable Through Title V Permit

12. Biogas sampling shall be conducted using the methods and procedures approved by the District. The District shall be notified each time the biogas sampling frequency changes. [District Rule 1081] Federally Enforceable Through Title V Permit

13. A flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311] Federally Enforceable Through Title V Permit

14. Flare outlet shall be equipped with an automatic ignition system, or, shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311] Federally Enforceable Through Title V Permit

15. Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an alternative equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. [District Rule 4311] Federally Enforceable Through Title V Permit

16. If the flare is equipped with a flow-sensing automatic ignition system and does not use a continuous flame pilot, the flare shall use purge gas for purging. [District Rule 4311] Federally Enforceable Through Title V Permit

17. Flaring is prohibited unless it is consistent with an approved flare minimization plan (FMP), pursuant to Section 6.5 of District Rule 4311, and all commitments listed in that plan have been met. This standard does not apply if the APCO determines that the flaring is caused by an emergency as defined by Section 3.7 and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere. [District Rule 4311] Federally Enforceable Through Title V Permit

18. The operator shall monitor and record the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. [District Rule 4311] Federally Enforceable Through Title V Permit

19. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 of Rule 4311 shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, which ever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

20. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 of Rule 4311 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. The report shall include, but is not limited to all of the following: the results of an investigation to determine the primary cause and contributing factors of the flaring event; any prevention measures considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented; if appropriate, an explanation of why the flaring was an emergency and necessary to prevent accident, hazard or release of vent gas to the atmosphere, or where, due to a regulatory mandate to vent a flare, it cannot be recovered, treated and used as a fuel gas at the facility; and the date, time, and duration of the flaring event. [District Rule 4311] Federally Enforceable Through Title V Permit

21. The operator of a flare subject to flare monitoring requirements pursuant to Section 5.10 of Rule 4311 shall submit an annual report to the APCO within 30 days following the end of each 12 month period. The report shall include the following: the total volumetric flow of vent gas in standard cubic feet for each day; a flow verification report which shall include flow verification testing pursuant to Section 6.3.5 of Rule 4311. [District Rule 4311] Federally Enforceable Through Title V Permit

22. For purposes of the flow verification report required by Section 6.2.3.8 of Rule 4311, vent gas flow shall be determined using one or more of the following methods, or by any alternative method approved by the APCO, ARB, and EPA: EPA Methods 1 and 2; a verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 5.10 of Rule 4311; tracer gas dilution or velocity; other flow monitors or process monitors that can provide comparison data on a vent stream that is being directed past the ultrasonic flow meter. [District Rule 4311] Federally Enforceable Through Title V Permit

23. The operator shall submit a flare minimization plan to the District for approval that includes all of the data required under Section 6.5 of Rule 4311 prior to installing the equipment authorized by this Authority to Construct. [District Rule 4311] Federally Enforceable Through Title V Permit

24. Every five years after the initial FMP submittal, the operator shall submit an updated FMP for each flare to the APCO for approval. The current FMP shall remain in effect until the updated FMP is approved by the APCO. If the operator fails to submit an updated FMP as required by this section, the existing FMP shall no longer be considered an approved plan. [District Rule 4311] Federally Enforceable Through Title V Permit

25. An updated FMP shall be submitted by the operator pursuant to Section 6.5 of Rule 4311 addressing new or modified equipment, prior to installing the equipment. Updated FMP submittals are only required if: (1) The equipment change would require an authority to construct (ATC) and would impact the emissions from the flare, and (2) The ATC is deemed complete after June 18, 2009, and (3) The modification is not solely the removal or decommissioning of equipment that is listed in the FMP, and has no associated increase in flare emissions. [District Rule 4311] Federally Enforceable Through Title V Permit

26. The anaerobic digester system and its associated piping shall be inspected for leaks at least annually. Any leak detected on the basis of sight, smell, or sound, shall be recorded and a corrective action shall be taken to eliminate the leak. [District Rule 2201] Federally Enforceable Through Title V Permit

27. Records of leak inspections shall contain at least an identification of a person performing an inspection, date and time of the inspection, leak location, and corrective action taken to eliminate leaks. The records shall be maintained, kept, and made available for District inspection upon request. [District Rule 2201] Federally Enforceable Through Title V Permit

28. The permittee shall maintain records of: (1) the name of the sampler, and the date and time of biogas sampling for H2S, (2) the name of the tester, and the date and time of biogas testing for H2S, (3) test results showing the biogas concentration (in ppmv) of H2S. [District Rule 1081] Federally Enforceable Through Title V Permit

29. Permittee shall maintain the following records: a copy of the approved flare minimization plan pursuant to Section 6.5; a copy of annual reports submitted to the APCO pursuant to Section 6.2 of District Rule 4311. [District Rule 4311] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

30. Permittee shall maintain records of the following when the flare is used during an emergency: duration of flare operation, amount of gas burned, and the nature of the emergency situation. [District Rule 4311] Federally Enforceable Through Title V Permit

31. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation of the flare. [District Rule 2201]

32. All records shall be retained for a minimum of five years, and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4311] Federally Enforceable Through Title V Permit

APPENDIX B

Draft ATCs N-1237-661-5 and -892-0

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-1237-661-5 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: E & J GALLO WINERY
MAILING ADDRESS: ATTN: EHS MANAGER
18000 W RIVER RD
LIVINGSTON, CA 95334

LOCATION: 18000 W RIVER RD
LIVINGSTON, CA 95334

EQUIPMENT DESCRIPTION:
MODIFICATION OF DIGESTER GAS OPERATION COMPOSED OF A WASTE WATER TREATMENT SYSTEM WITH AN EQUALIZATION TANK, HIGH RATE ANAEROBIC DIGESTER, TWO LOW RATE ANAEROBIC DIGESTERS, AND MEMBRANE BIOLOGICAL REACTOR SYSTEM CONSISTING OF AN ANOXIC TANK, A PRE-AERATION TANK, AND TWO MEMBRANE BIOLOGICAL REACTORS WITH BIOGAS SENT TO ONE BIOLOGICAL SCRUBBER, TWO ACTIVATED CARBON FILTERS, THE DIGESTER GAS WILL BE ROUTED TO TWO IC ENGINES (PERMITS N-1237-605 AND '606), OR TO A 600 CFM (EQUIVALENT TO 32.4 MMBTU/HR) OVIVO GWE ENCLOSED EMERGENCY FLARE: MODIFY PERMIT TO ALLOW BIOGAS TO BE SENT TO ANY EQUIPMENT AUTHORIZED TO RECEIVE BIOGAS

CONDITIONS

1. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
2. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
5. Visible emissions from the flare serving the anaerobic digesters shall not equal or exceed Ringelmann 1/4 or 5% opacity for a period or periods aggregating more than three minutes in any one hour. [District Rules 2201 and 4101] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU <u>MUST</u> NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 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

DRAFT

Brian Clements, Director of Permit Services

6. {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]
7. The anaerobic digester system and its associated piping shall be maintained leak free. [District Rule 2201] Federally Enforceable Through Title V Permit
8. This flare shall only be fired on biogas collected from the anaerobic digester system. [District Rule 2201] Federally Enforceable Through Title V Permit
9. The flare shall be operated only for maintenance, testing, required regulatory purposes, and during periods where both engines, permits N-1237-605 and N-1237-606, cannot be operated due to an emergency, as defined in this permit. Operation of the flare for maintenance, testing, and required regulatory purposes shall not exceed 200 hours per year. [District Rules 2201 and 4311] Federally Enforceable Through Title V Permit
10. An emergency is defined as any situation or a condition arising from a sudden and reasonably unforeseeable and unpreventable event beyond the control of the operator. Examples include, but are not unlimited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility. A flaring event due to improperly designed equipment, lack of preventative maintenance, careless or improper operation, operator error, or willful misconduct does not qualify as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered as an emergency. [District Rules 2201 and 4311] Federally Enforceable Through Title V Permit
11. Emissions from the flare shall not exceed any of the following limits: 0.06 lb-NOx/MMBtu (as NO2); 0.008 lb-PM10/MMBtu; 0.75 lb-CO/MMBtu; or 0.019 lb-VOC/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit
12. The sulfur content of the biogas being incinerated by the flare shall not exceed 40 ppmv (as H2S). [District Rule 2201] Federally Enforceable Through Title V Permit
13. The sulfur content of the digester gas combusted in this flare shall be monitored and recorded weekly. After eight (8) consecutive weekly tests show compliance, the digester gas sulfur content monitoring frequency may be reduced to once every calendar quarter. If quarterly monitoring shows a violation of the digester gas sulfur content limit of this permit, then weekly monitoring shall resume and continue until eight consecutive weeks of monitoring show compliance with the gas sulfur content limit. Once compliance with the gas sulfur content limit is shown for eight consecutive weeks, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas shall not be required if the flare does not operate during that period. Records of the results of monitoring of the digester gas sulfur content shall be maintained. [District Rule 2201] Federally Enforceable Through Title V Permit
14. Monitoring of the digester gas sulfur content shall be performed using a Testo 350 XL portable emission monitor; District-approved in-line H2S monitors; gas detection tubes calibrated for H2S; District-approved source test methods, including EPA Method 11 or EPA Method 15, ASTM Method D1072, D4084, and D5504; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201] Federally Enforceable Through Title V Permit
15. Biogas sampling shall be conducted using the methods and procedures approved by the District. The District shall be notified each time the biogas sampling frequency changes. [District Rule 1081] Federally Enforceable Through Title V Permit
16. A flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311] Federally Enforceable Through Title V Permit
17. The flare outlet shall be equipped with an automatic ignition system, or shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

18. Unless the flare is equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. The flame detection device shall be kept operational at all times except during flare maintenance when the flare is isolated from gas flow. During essential planned power outages when the flare is operating, the pilot monitor is allowed to be non-functional if the flare flame is clearly visible to onsite operators. All pilot monitor downtime shall be reported annually pursuant to Rule 4311, Section 6.2.3.6. [District Rule 4311] Federally Enforceable Through Title V Permit

19. Flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. [District Rule 4311] Federally Enforceable Through Title V Permit

20. Flaring is prohibited unless it is consistent with an approved flare minimization plan (FMP), pursuant to District Rule 4311, Section 6.5, and all commitments listed in that plan have been met. This standard does not apply if the APCO determines that the flaring is caused by an emergency as defined by District Rule 4311, Section 3.7 and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere. [District Rule 4311] Federally Enforceable Through Title V Permit

21. The operator shall monitor and record the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. [District Rule 4311] Federally Enforceable Through Title V Permit

22. The operator shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311] Federally Enforceable Through Title V Permit

23. The operator shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the previous calendar year. The report shall include, but is not limited to all of the following: 1) The results of an investigation to determine the primary cause and contributing factors of the flaring event; 2) Any prevention measures considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented; 3) If appropriate, an explanation of why the flaring was an emergency and necessary to prevent accident, hazard or release of vent gas to the atmosphere, or where, due to a regulatory mandate to vent a flare, it cannot be recovered, treated and used as a fuel gas at the facility; and 4) The date, time, and duration of the flaring event. [District Rule 4311] Federally Enforceable Through Title V Permit

24. The operator shall submit an annual report to the APCO within 30 days following the end of each 12 month period. The report shall include the following: the total volumetric flow of vent gas in standard cubic feet for each day for the previous calendar year; a flow verification report which shall include flow verification testing pursuant to Section 6.3.5 of Rule 4311. [District Rule 4311] Federally Enforceable Through Title V Permit

25. For purposes of the flow verification report required by Section 6.2.3.8 of Rule 4311, vent gas flow shall be determined using one or more of the following methods, or by any alternative method approved by the APCO, ARB, and EPA: EPA Methods 1 and 2; a verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 5.10 of Rule 4311; tracer gas dilution or velocity; other flow monitors or process monitors that can provide comparison data on a vent stream that is being directed past the ultrasonic flow meter. [District Rule 4311] Federally Enforceable Through Title V Permit

26. Every five years after the initial FMP submittal, the operator shall submit an updated FMP for each flare to the APCO for approval. The current FMP shall remain in effect until the updated FMP is approved by the APCO. If the operator fails to submit an updated FMP as required by this section, the existing FMP shall no longer be considered an approved plan. [District Rule 4311] Federally Enforceable Through Title V Permit

27. An updated FMP shall be submitted by the operator pursuant to Rule 4311, Section 6.5 addressing new or modified equipment, prior to installing the equipment. Updated FMP submittals are only required if: 1) The equipment change would require an authority to construct (ATC) and would impact the emissions from the flare, and 2) The modification is not solely the removal or decommissioning of equipment that is listed in the FMP, and has no associated increase in flare emissions. [District Rule 4311] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

28. The anaerobic digester system and its associated piping shall be inspected for leaks at least annually. Any leak detected on the basis of sight, smell, or sound, shall be recorded and a corrective action shall be taken to eliminate the leak. [District Rule 2201] Federally Enforceable Through Title V Permit

29. Records of leak inspections shall contain at least an identification of a person performing an inspection, date and time of the inspection, leak location, and corrective action taken to eliminate leaks. The records shall be maintained, kept, and made available for District inspection upon request. [District Rule 2201] Federally Enforceable Through Title V Permit

30. The permittee shall maintain records of: (1) the name of the sampler, and the date and time of biogas sampling for H2S, (2) the name of the tester, and the date and time of biogas testing for H2S, (3) test results showing the biogas concentration (in ppmv) of H2S. [District Rule 1081] Federally Enforceable Through Title V Permit

31. Permittee shall maintain the following records: a copy of the approved flare minimization plan pursuant to Section 6.5; a copy of annual reports submitted to the APCO pursuant to Section 6.2 of District Rule 4311. [District Rule 4311] Federally Enforceable Through Title V Permit

32. Permittee shall maintain records of the following when the flare is used during an emergency: duration of flare operation, amount of gas burned, and the nature of the emergency situation. [District Rule 4311] Federally Enforceable Through Title V Permit

33. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation of the flare. [District Rule 2201]

34. All records shall be retained for a minimum of five years, and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4311] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-1237-892-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: E & J GALLO WINERY
MAILING ADDRESS: ATTN: EHS MANAGER
18000 W RIVER RD
LIVINGSTON, CA 95334

LOCATION: 18000 W RIVER RD
LIVINGSTON, CA 95334

EQUIPMENT DESCRIPTION:
1,966 BHP JENBACHER MODEL JMC420 GS NATURAL GAS/DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AND OXIDATION CATALYST POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
2. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
3. Prior to operating equipment under this Authority to Construct (ATC), permittee shall surrender NOx emission reduction credits (ERCs) for the following quantity of emissions: 1st quarter - 727 lb, 2nd quarter - 727 lb, 3rd quarter - 728 lb, and 4th quarter - 728 lb. These amounts include the applicable offset ratio specified in Rule 2201, Section 4.8 (as amended 8/15/19). NOx ERCs used to satisfy the offset quantity required under District Rule 2201 must be surplus at the time of issuance of this ATC and the total quantity of ERCs surrendered shall be calculated based on the ERC surplus value percent discount of each ERC certificate used. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU <u>MUST</u> NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 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

DRAFT

Brian Clements, Director of Permit Services

4. ERC Certificate Number N-1568-2 (or certificates split from this certificate) shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District, upon which this ATC shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this ATC. [District Rule 2201] Federally Enforceable Through Title V Permit

5. Prior to operating equipment under this Authority to Construct (ATC), permittee shall surrender VOC emission reduction credits (ERCs) for the following quantity of emissions: 1st quarter - 682 lb, 2nd quarter - 682 lb, 3rd quarter - 683 lb, and 4th quarter - 683 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 8/15/19). VOC ERCs used to satisfy the offset quantity required under District Rule 2201 must be surplus at the time of issuance of this ATC and the total quantity of ERCs surrendered shall be calculated based on the ERC surplus value percent discount of each ERC certificate used. [District Rule 2201] Federally Enforceable Through Title V Permit

6. ERC Certificate Numbers S-4751-1 and C-1404-1 (or certificates split from these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District, upon which this ATC shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this ATC. [District Rule 2201] Federally Enforceable Through Title V Permit

7. 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 and 40 CFR 60.4243] Federally Enforceable Through Title V Permit

8. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

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

10. 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] Federally Enforceable Through Title V Permit

11. {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]

12. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the California Air Resources Board (CARB) document titled Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081] Federally Enforceable Through Title V Permit

13. Operation of this engine shall not exceed 8,400 hours in any 12 consecutive month period. [District Rule 2201] Federally Enforceable Through Title V Permit

14. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702] Federally Enforceable Through Title V Permit

15. This engine shall only be fueled with PUC-regulated natural gas, digester gas, or a blend of PUC-regulated natural gas and digester gas. [District Rules 2201, 4702, and 4801] Federally Enforceable Through Title V Permit

16. The sulfur content of the digester gas and natural gas/digester gas blends used as fuel in this engine shall not exceed 40 ppmv as H2S. An averaging period of up to one calendar day in length may be utilized for demonstration of compliance with the digester gas sulfur content limit. [District Rules 2201, 4702, and 4801] Federally Enforceable Through Title V Permit

17. 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] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

18. The commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial tuning and testing and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 50 hours of operation. [District Rule 2201] Federally Enforceable Through Title V Permit

19. The owner/operator shall minimize the emissions from the engine to the maximum extent feasible during the commissioning period. [District Rule 2201] Federally Enforceable Through Title V Permit

20. The oxidation catalyst(s) shall be installed and ready for operation prior to commencement of the commissioning period. [District Rule 2201] Federally Enforceable Through Title V Permit

21. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201] Federally Enforceable Through Title V Permit

22. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201] Federally Enforceable Through Title V Permit

23. The permittee shall prepare and maintain a summary of activities to be performed during the commissioning period 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, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201] Federally Enforceable Through Title V Permit

24. During the commissioning period, emission rates from this IC engine shall not exceed any of the following limits: 0.6 g-NOx/bhp-hr, 0.05 g-PM10/bhp-hr, 0.14 g-CO/bhp-hr, or 0.050 g-VOC/bhp-hr. [District Rule 2201] Federally Enforceable Through Title V Permit

25. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 50 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. Upon completion of these activities, the unused balance of the 50 firing hours without abatement shall expire. [District Rule 2201] Federally Enforceable Through Title V Permit

26. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201] Federally Enforceable Through Title V Permit

27. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.049 g-NOx/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.050 g-NOx/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 4.1 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.032 g-PM10/bhp-hr when fueled with natural gas, and 0.05 g-PM10/bhp-hr when fueled with digester gas or a natural gas/digester gas blend; 0.14 g-CO/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.14 g-CO/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 19.5 ppmvd CO @ 15%); and 0.049 g-VOC/bhp-hr when 50% or less of the fuel heat input is from digester gas and 0.050 g-NOx/bhp-hr when more than 50% of the fuel heat input is from digester gas (equivalent to 12.0 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201, 4102, and 4702, and 40 CFR 60.4233] Federally Enforceable Through Title V Permit

28. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

29. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days of initial start-up. [District Rules 1081, 2201, and 4702, and 40 CFR 60.4243] Federally Enforceable Through Title V Permit

30. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 8,760 hours of operation or 24 months, whichever comes first. [District Rules 1081, 2201, and 4702 and 40 CFR 60.4243] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

31. 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] Federally Enforceable Through Title V Permit

32. The results of each source test shall be submitted to the District and EPA within 60 days after completion of the source test. [District Rule 1081 and 40 CFR 60.4245] Federally Enforceable Through Title V Permit

33. 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 and 40 CFR 60.4244] Federally Enforceable Through Title V Permit

34. For emissions source testing, the arithmetic average of three 60-consecutive-minute test runs shall apply. Each test run shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. 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 (however, VOC may also be reported as propane only for demonstration of compliance with the VOC limits in 40 CFR 60 Subpart JJJJ). NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rule 4702 and 40 CFR 60.4244] Federally Enforceable Through Title V Permit

35. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E; CO (ppmv) - EPA Method 10; VOC (ppmv) - EPA Method 18, or 25A or 25B; stack gas oxygen - EPA Method 3 or 3A; stack gas velocity/volumetric flowrate - 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 EPA and the District may be used to address the source testing requirements of this permit. [District Rules 1081, 2201, and 4702] Federally Enforceable Through Title V Permit

36. 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 EPA and the District. [District Rules 2201 and 4702] Federally Enforceable Through Title V Permit

37. Fuel sulfur content analysis of the digester gas used to fuel this engine shall be performed within 60 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate, or an alternative method approved by EPA and the District. [District Rules 2201 and 4702] Federally Enforceable Through Title V Permit

38. Fuel sulfur content analysis of the digester gas used to fuel this engine shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate, or an alternative method approved by EPA and the District. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702] Federally Enforceable Through Title V Permit

39. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201] Federally Enforceable Through Title V Permit

40. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; District-approved test methods, including EPA Method 11 or EPA Method 15, ASTM Method D1072, D1945, D4084, D4468, D4810 or D5504; a continuous analyzer employing gas chromatography; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; or an alternative method approved by EPA and the District. The permittee shall maintain records of any in-line monitors used to demonstrate compliance with the digester gas sulfur content limit of this permit, including the make, model, and detection limits of the monitor(s). [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

41. Coincident with the end of the commissioning period, the permittee shall monitor and record the stack concentration of NOx and O2 at least once every day (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702, and 40 CFR 64] Federally Enforceable Through Title V Permit

42. The permittee shall monitor and record the stack concentration of CO and O2 at least once every calendar month (in which a source test is not performed) using a portable emission monitor that satisfies District specifications or in-stack emission monitors that satisfy District specifications required for portable analyzers. 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. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702] Federally Enforceable Through Title V Permit

43. In-stack emission monitors shall be calibrated using EPA protocol calibration gases a minimum of once within every 30 days. Records of calibration dates, instruments calibrated, gas readings prior to calibration, calibration gases used, and calibration gas certification and expiration dates shall be maintained. [District Rules 1080 and 4702, and 40 CFR 64] Federally Enforceable Through Title V Permit

44. Portable emission monitors shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Calibration records shall be shall be maintained. [District Rules 1080 and 4702, and 40 CFR 64] Federally Enforceable Through Title V Permit

45. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar month 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 month. [District Rules 2201 and 4102] Federally Enforceable Through Title V Permit

46. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer, the District-approved in-stack emission monitor(s), or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), 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, in-stack emission monitor, or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) 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, and 40 CFR 64] Federally Enforceable Through Title V Permit

47. 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 and any in-stack emission monitors 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] Federally Enforceable Through Title V Permit

48. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of portable emission analyzer(s) and in-stack emission analyzer(s), (4) emission 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, and 40 CFR 64] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

49. 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] Federally Enforceable Through Title V Permit

50. This engine shall be operated within the ranges that the source testing has shown result in pollution emission rates within the emissions limits as specified on this permit. [District Rules 2201 and 4702] Federally Enforceable Through Title V Permit

51. 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 hours of operation for commissioning of the engine, the total hours of operation, the type and quantity of each fuel used, 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, 4701, and 4702, and 40 CFR 60.4243 and 40 CFR 60.4245] Federally Enforceable Through Title V Permit

52. Records shall be maintained of the composition of the fuel used during each source test, including the percent blend of natural gas and digester gas on a volumetric and heat input basis in the fuel used. [District Rule 2201] Federally Enforceable Through Title V Permit

53. 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] Federally Enforceable Through Title V Permit

54. The permittee shall document that the natural gas used as fuel in the engine is from a PUC regulated source. Valid purchase contracts, supplier certifications, tariff sheets, or transportation contacts may be used to satisfy this requirement. [District Rules 2201 and 4702] Federally Enforceable Through Title V Permit

55. Records shall be maintained of the total hours of operation of this engine, calculated on a rolling 12-month basis. [District Rule 2201] Federally Enforceable Through Title V Permit

56. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 2201 and 4702 and 40 CFR 60.4245] Federally Enforceable Through Title V Permit

57. The permittee shall comply with the compliance assurance monitoring operation and maintenance requirements of 40 CFR 64.7. [40 CFR 64.7] Federally Enforceable Through Title V Permit

58. If the District or EPA determine that a Quality Improvement Plan is required under 40 CFR 64.7(d)(2), the permittee shall develop and implement the Quality Improvement Plan in accordance with 40 CFR 64.8. [40 CFR 64.8] Federally Enforceable Through Title V Permit

59. The permittee shall comply with the record keeping and reporting requirements of 40 CFR part 64.9. [40 CFR 64.9] Federally Enforceable Through Title V Permit

60. Notification of the date construction of this engine commenced shall be submitted to the District and EPA and shall be postmarked no later than 30 days after such date as construction commenced. The notification shall contain the following information: 1) Name and address of the owner or operator; 2) The address of the affected source; 3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; 4) Emission control equipment; and 5) Fuel used. Notification of construction and copies of source test results shall be submitted to EPA at the following address: Director, Air Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, CA 94105. [40 CFR 60.4245] Federally Enforceable Through Title V Permit

APPENDIX C

Analysis of Digester Gas at the Facility

STACK GAS FLOW RATE DETERMINATION -- FUEL USAGE

Facility: E&J Gallo Winery
Unit: 1393 BHP Generators #1
Condition: Normal Operation
Date: 2/21/2018
Personel:
Time:

	Run 1	Run 2	Run3	
Gross Calorific Value @ 68°F	749.43	749.43	749.43	Btu / ft^3
Stack Oxygen	8.85	8.84	8.91	%
Gas Fd-Factor @ 68°F	8920	8920	8920	DSCF/MMBtu
Gas Temperature (°F)	60	60	60	°F
Standard Temperature (°F)	60	60	60	°F

	Run 1	Run 2	Run3	
Corrected Fuel Rate (SCFM) @ 68°F	220.22	211.85	213.65	SCFM
Fuel Flowrate (SCFH)	13,213	12,711	12,819	SCFH
Million Btu per minute	0.165	0.159	0.160	MMBtu/min
Heat Input (MMBtu/hour)	9.90	9.53	9.61	MMBtu/Hr

	Run 1	Run 2	Run3	
Stack Gas Flow Rate	**2,515**	**2,418**	**2,451**	**DSCFM**

WHERE:

Gas Fd-Factor = Fuel conversion factor (ratio of combustion gas volumes to heat inputs)
MMBtu = Milion Btu

CALCULATIONS:

SCFM = CFM * 528 * (gas line PSIA) / 14.7 / (gas °F + 460)
MMBtu/min = (SCFM * Btu/ft^3) / 1,000,000
DSCFM = Gas Fd-Factor * MMBtu/min * 20.9/ (20.9 - stack oxygen%)
SCFH = SCFM * 60
Heat Input = MMBtu/min * 60

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APPENDIX D

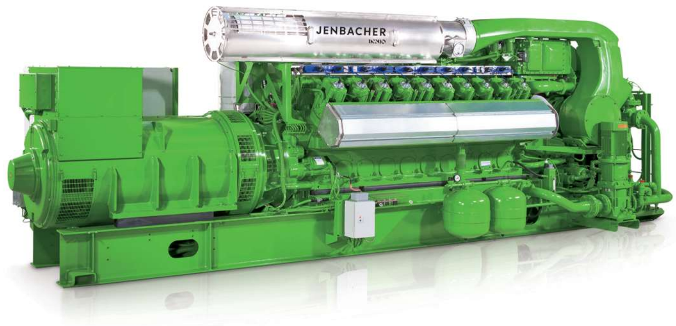
Data Sheet for Proposed IC Engine

JENBACHER

Jenbacher type 4

An efficiency milestone

Based on the proven design concepts of types 3 and 6, the modern Jenbacher* type 4 engines in the 800 to 1,500 kW power range are characterized by a high-power density and outstanding efficiency. The enhanced control and monitoring provide easy preventive maintenance, high reliability and availability.



Reference installations

J420 St Bart's Hospital in London, United Kingdom

Fuel	Engine type	Electrical output	Thermal output	Commissioning
Natural gas	1 x J420	1,480 kW	5,546 MBTU/hr	2015

Since 2015, one of the oldest hospitals in the UK has obtained cooling, heat and power from a single J420 unit. The 1.4 MW cogeneration unit includes a 250 kW absorption chiller that delivers cooling water to the hospital. The J420 engine is the cornerstone of a new energy center that has provided the facility with financial savings by boosting its energy efficiency, reliability and durability.

J420 Ashford Power Peaking Plant in Kent, United Kingdom

Fuel	Engine type	Electrical output	Commissioning
Natural gas	14 x J420	21 MW	2018

The electricity generating peaking plant at Ashford Power, Kings North Industrial Estate in Kent is operating 14 containerized Jenbacher J420 engines. When not in operation, the engines of this fully-automated plant wait on standby, prepared to be called upon and ramped up in less than 2 minutes.

J420 SV.CO Strijbisverbeek Greenhouse in Maasdijuk, the Netherlands

Fuel	Engine type	Electrical output	Thermal output	Commissioning
Natural gas	1 x J420	1,501 kW	6,817 MBTU/hr	2018

The Strijbisverbeek Greenhouse in Maasdijuk, Netherlands, is relying on a total greenhouse CHP solution consisting of a Jenbacher J420, a complete exhaust gas system incl. catalytic reactor for CO_2 and acoustical enclosure. The energy generated in this greenhouse is used to operate its grow lights. Additionally, they are using the heat of the CHP to heat up their greenhouse in colder periods and at night.

J420 Biogas Plant in Nakornrachasrima, Thailand

Fuel	Engine type	Electrical output	Commissioning
Biogas	5 x J420	7,105 kW	2012

The Chok Yuen Yong facility profits from its five J420 engines that provide reliable on-site power while also reducing electrical and energy costs. The excess electricity produced is supplied to the public grid.

INNIO

JENBACHER

Technical features

Feature	Description	Advantages
Heat recovery	Flexible arrangement of heat exchanger, two stage oil plate heat exchanger on demand	- High thermal efficiency, even at high and fluctuating return temperatures
Gas dosing valve	Electronically controlled gas dosing valve with high degree of control accuracy	- Very quick response time - Rapid adjustment of air / gas ratio - Large adjustable calorific value range
Four-valve cylinder head	Enhanced swirl and channel geometry using advanced calculation and simulation methods (CFD)	- Reduced charge-exchange losses - Central spark-plug position resulting in optimal cooling and combustion conditions
Crack connecting rod	Applying a technology – tried and tested in the automotive industry – in our powerful stationary engines	- High dimensional stability and accuracy - Reduced connecting rod bearing wear - Easy to maintain

Technical data

Configuration			V 70°
Bore (inch)			5.71
Stroke (inch)			7.28
Displacement / cylinder (cu.in)			186,7
Speed (rpm)			1,800 (60 Hz)
Mean piston speed (in/s)			437
Scope of supply			Generator set, cogeneration system, generator set / cogeneration in container
Applicable gas types			Natural gas, flare gas, biogas, landfill gas, sewage gas. Special gases (e.g., coal mine gas, coke gas, wood gas, pyrolysis gas)
Engine type	J412	J416	J420
No. of cylinders	12	16	20
Total displacement (cu.in)	2,239	2,984	3,728

Dimensions l x w x h (inch)		
Generator set	J412	220 x 75 x 90
	J416	250 x 75 x 90
	J420	280 x 75 x 90
Cogeneration system	J412	240 x 75 x 90
	J416	270 x 75 x 90
	J420	280 x 75 x 90
Container	J412	480 x 120 x 110
	J416	480 x 120 x 110
	J420	480 x 120 x 110

Weights empty (lbs)	J412	J416	J420
Generator set	24,480	27,780	34,620
Cogeneration system	25,800	29,100	35,490
Container 40-foot (cogeneration)	62,850	68,270	81,550

Outputs and efficiencies

Natural gas 1.800 rpm | 60 Hz

NOx <	Type	Pel (kW)[1]	Pth (MBTU/hr)[2]	ηel (%)[1]	ηth (%)[2]	ηtot (%)
1.0 g/bhp.hr	J412	851	3,344	41.2	47.4	88.6
	J416	1,141	4,459	41.4	47.4	88.9
	J420	1,429	5,570	41.5	47.4	88.9
0.6 g/bhpr	J412	851	3,483	40.1	48.1	88.2
	J416	1,141	4,647	40.3	48.1	88.5
	J420	1,429	5,808	40.4	48.1	88.5

Biogas 1,800 rpm | 60 Hz

NOx <	Type	Pel (kW)[1]	Pth (MBTU/hr)[2]	ηel (%)[1]	ηth (%)[2]	ηtot (%)
1.0 g/bhp.hr	J412	851	3,334	39.7	45.6	85.3
	J416	1,141	4,443	39.9	45.5	85.5
	J420	1,429	5,552	40.0	45.5	85.5
0.6 g/bhpr	J412	851	3,446	38.8	46.1	84.9
	J416	1,141	4,596	39.0	46.1	85.1
	J420	1,429	5,739	39.1	46.0	85.1

1) Technical data according to ISO 3046
2) Total heat output with a tolerance of +/- 8 %, exhaust gas outlet temperature 120°C, for biogas gas outlet temperature 180°C
All data according to full load and subject to technical development and modification.
Further engines versions available on request.

Find your local support online:
www.innio.com/en/company/providers

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APPENDIX E

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:

$PE2_{quarterly} = PE2_{annual} \div 4$ quarters/year

$PE1_{quarterly} = PE1_{annual} \div 4$ quarters/year

Quarterly NEC [QNEC] for N-1237-892			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	97.25	97.25	0.00
SO_X	17.00	17.00	0.00
PM_{10}	13.00	13.00	0.00
CO	486.00	486.00	0.00
VOC	3.25	3.25	0.00

Quarterly NEC [QNEC] for N-1237-892			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	494.00	0	494.00
SO_X	273.00	0	273.00
PM_{10}	455.00	0	455.00
CO	1,274.25	0	1,274.25
VOC	455.00	0	455.00

APPENDIX F

BACT Analysis for IC Engine when Fueled with Natural Gas

Top-Down BACT Analysis for Natural Gas/Digester Gas-Fired IC Engine When Fueled with Natural Gas

Previous District BACT Guideline 3.3.12 – Non-Agricultural Fossil Fuel-Fired IC Engines > 50 bhp, which was rescinded on March 7, 2019, listed the BACT requirements for full-time fossil fuel-fired IC engines. Because there is no existing District BACT Guideline that applies to the proposed natural gas/digester gas-fired IC engine when it is fueled with natural gas, a project-specific BACT analysis will be performed in accordance the District BACT policy to determine the BACT requirements for the proposed engine when it is fueled with natural gas.

I. Proposal

E & J Gallo Winery has requested an Authority to Construct (ATC) permit for the installation of a new 1,966 bhp lean-burn IC engine with a selective catalytic reduction (SCR) system to control emissions that will power a 1,429 kW electrical generator and will be fueled with natural gas and digester gas from the existing wastewater anaerobic reactor (ATC N-1237-892-0). The applicant has proposed to limit operation of the new IC engine to 8,400 hours per year.

II. BACT Applicability

New Emissions Unit with PE > 2.0 lb/day

BACT Applicability for New Emissions Unit for N-1237-892-0 When Fueled with Natural Gas				
Pollutant	PE2 for the New Engine (lb/day)	BACT Threshold (lb/day)	SSPE2 (lb/yr)	BACT Triggered?
NO_X (Normal Operation)	5.1	> 2.0	N/A	**Yes***
SO_X	0.9	> 2.0	N/A	No
PM_{10}	3.3	> 2.0	N/A	**Yes**
CO	14.6	> 2.0 and SSPE2 ≥ 200,000 lb/yr*	730,311	**Yes**
VOC	5.1	> 2.0	N/A	**Yes***
NH_3	4.6	> 2.0	N/A	No***

* BACT for NO_X and VOC also triggered for Federal Major Modifications for these pollutants

** BACT is not required for CO from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

*** NH_3 slip results from operation of an emissions control device (SCR) and, therefore, NH_3 emissions do not trigger BACT. However, NH_3 slip emissions from the proposed unit will still be limited by the permit to no more than 10 ppmv @ 15% O_2.

III. Top-Down BACT Analyses for the Natural Gas/Digester Gas-Fired Engine when Fueled with Natural Gas

As stated above, a project-specific BACT analysis will be performed for the proposed natural gas/digester gas-fired IC engine evaluated under this project when it is fueled with natural gas.

1. BACT Analysis for NO_X Emissions:

a. Step 1 - List all control technologies

The District's most recent previous BACT guideline full-time fossil fuel-fired IC engines, District BACT Guideline 3.3.12, listed the following BACT requirements for NO_X from full-time fossil fuel-fired IC engines.

Previous SJVAPCD BACT Guideline 3.3.12 for Fossil Fuel-Fired IC Engines NO_X Emission Requirements		
Achieved in Practice	Technologically Feasible	Alternate Basic Equipment
0.07 g-NO_X/bhp-hr or 5 ppmvd @ 15% O_2	--	1. 2 ppmv @ 15% O_2 Natural Gas-Fired Turbine 2. Electric Motor (except for engines that will be used to generate electricity)

In addition, the USA Environmental Protection Agency (USEPA) RACT/BACT/LAER, the California Air Resources Board (CARB) BACT Clearinghouse, and the South Coast Air Quality Management District (SCAQMD), the Ventura County Air Pollution Control District (VCAPCD), the Bay Area Air Quality Management District (BAAQMD), and the Sacramento Metropolitan Air Quality Management District (SMAQMD) BACT Guidelines were reviewed to determine potential control technologies for this class and category of operation. The District also reviewed the applicable IC engine rules from BAAQMD and SCAQMD, and SMAQMD. The following table summarizes the results of the review of these BACT guidelines and air district rules:

BACT Guideline Source	Equipment Rating	NO_X Control Technology/Requirement
District Rule 4702	> 50 bhp	5 ppmvd @ 15% O_2
SCAQMD BACT Guidelines Part B - IC Engine, Stationary, Non-Emergency, Electrical Generators (2-5-2021)	147 bhp and 385 bhp	0.07 lb-NO_X/MW-hr (Tecogen Ultera Emissions Retrofit Kit control system, comprised of Three-Way Catalyst with Air/Fuel Ratio Controller and Oxidation Catalyst)
SCAQMD BACT Guidelines Part D IC Engine, Stationary, Non-Emergency, Electrical Generators (2-5-2018)	> 50 bhp	Compliance with SCAQMD Rule 1110.2 (2-2-2018)
SCAQMD Rule 1110.2	New non-emergency Electrical Generators > 2/1/2008	NOx Emission Standard: 0.070 lb-NO_X/MW-hr *When determining compliance with the lb/MW-hr NO_X requirement, engines with heat recovery may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr) in addition to each MW-hr of net electricity produced ($MW_{e\text{-}hr}$)
Sacramento Metropolitan AQMD BACT Determination 143 (Expired)	> 50 bhp	5 ppmvd @ 15% O_2

BACT Guideline Source	Equipment Rating	NO_X Control Technology/Requirement
District Rule 4702	> 50 bhp	5 ppmvd @ 15% O_2
Sacramento Metropolitan AQMD Rule 412	> 50 bhp	Rich Burn 25 ppmv @ 15% O_2 Lean Burn 125 ppmv @ 15% O_2
Bay Area AQMD BACT Workbook Spark Ignition – Natural Gas Fired (Lean Burn)	≥ 50 bhp	Achieved in Practice 0.15 g/bhp-hr (12 ppmv @ 15% O_2) Technologically Feasible 0.07 g/bhp-hr (6 ppmv @ 15% O_2)
Bay Area AQMD BACT Workbook Spark Ignition, Natural Gas-Fired (Rich Burn)	≥ 50 bhp	Achieved in Practice 0.15 g/bhp-hr (9 ppmv @ 15% O_2) Technologically Feasible 0.071 g/bhp-hr (4 ppmv @ 15% O_2)
Bay Area AQMD BACT Workbook Internal Combustion Engine Stationary prime, Non-Agricultural (Compression Ignited)	> 50 bhp	Latest Tier Standard (Achieved in Practice) 85% reduction of current Tier Standard (Technologically Feasible)
Bay Area AQMD Regulation 9, Rule 8	> 50 bhp	Lean Burn Engines 70 ppmv @ 15% O_2 Rich Burn Engines 70 ppmv @ 15% O_2 Compression Ignited Engines 51 to 175 bhp: 180 ppmv @ 15% O_2 > 175 bhp: 110 ppmv @ 15% O_2
Monterey Bay APCD (From CARB BACT Clearinghouse) ICE: Spark Ignition, Natural Gas, Rich Burn 528 HP Engines	N/A	0.07 g/bhp-hr (Achieved in Practice)
Santa Barbara APCD (From CARB BACT Clearinghouse) ICE: 881 BHP Lean Burn IC Engine used for Cogeneration (2015)	N/A	0.063 g/bhp-hr (0.154 lb/MW-hr)
San Diego APCD (From CARB BACT Clearinghouse) ICE: Spark Ignition, Natural Gas, Lean burn 2328 bhp and 2889 bhp Engines	N/A	7 ppmvd @ 15% O_2 or 0.1 g/bhp-hr (Achieved in Practice)
Ventura County APCD ICE: Spark Ignition, Natural Gas, Lean Burn 6,032 BHP IC Engines	N/A	5 ppmvd @ 15% O_2 (Achieved in Practice)
EPA New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart IIII	N/A	Tier 4 Final for compression ignition IC engines (0.3 g-NO_X/bhp-hr – 0.5 g-NO_X/bhp-hr)

BACT Guideline Source	Equipment Rating	NO_X Control Technology/Requirement
District Rule 4702	> 50 bhp	5 ppmvd @ 15% O_2
EPA New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart JJJJ	N/A	1.0 g-NO_X/bhp-hr
EPA National Emission Standards for Hazardous Air Pollutants (NESHAPS) 40 CFR Part 63 Subpart ZZZZ	N/A	No Standard

Additionally, the District performed a detailed industry survey and review of IC engines permitted within the District that are used for electric power generation. The following survey is divided into two subcategories:

- **First Table:** IC engines with heat recovery
- **Second Table:** IC engines without heat recovery

For cogeneration units with a heat recovery system, the quantity of heat recovered was determined either from the manufacturer's data provided in the original permitting action, or from information that was provided by the facility for previous analyses.

As part of the industry survey, the District reviewed up to three recent emissions source tests to gather the NO_X emissions data for each engine. The following tables summarize the Districts review of NO_X emissions from permitted engines used for power generation.

NOTE:

For each table below:

Green Highlight	IC Engine Achieves 0.070 lb-NO_X/MW-hr or less
Red Highlight	IC Engine Does not Achieve 0.070 lb-NO_X/MW-hr

NOx Data for Engines Used for Power Generation With a Heat Recovery System								
Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted NOx Limit (ppmv at 15% O_2)	Heat Recovered-Design Value (MMBtu/hr)	lb-NOx/MW-hr (based on permitted NOx limit, with heat recovery)	NOx Source Test data (ppmv at 15% O_2) Year	Result	lb-NOx/MW-hr (based on highest NOx source test result, with heat recovery)
Atwater High N-1306-2-2	86	60	5	0.44	0.095	2013	**1.23**	0.018
						2015	1	
						2017	0.1	
Ripon Unified N-686-3-0	122	60	5	0.366	0.084	2014	0.07	0.045
						2016	**2.6**	
Sanger Unified C-3563-11-1	86	60	5	0.44	0.074	2013	**1.6**	0.024
						2015	1.6	
						2017	1.6	
Sanger Unified C-3563-12-1	86	60	5	0.44	0.074	2013	1.4	0.030
						2015	0.4	
						2017	**2.0**	
Sanger Unified C-7162-3-0	122	60	5	0.366	0.084	2012	0.7	0.024
						2014	0.01	
						2016	**1.37**	
Sanger Unified C-7162-4-0	122	60	5	0.366	0.084	2012	0.01	0.029
						2014	0.07	
						2016	**1.68**	
Dynatect Ro-Lab Inc. N-704-10-0	108	75	5	0.49	0.078	2014	0.6	0.049
						2016	0.6	
						2018	**3.27**	
Dynatect Ro-Lab Inc N-704-11-0	108	75	5	0.49	0.078	2014	**0.1**	0.002
						2016	0.02	
						2018	0.0	
Valley Chrome Plating C-1318-7-1	108	75	5	0.49	0.078	2013	0.2	0.006
						2015	0.2	
						2017	**0.4**	
Merced Community College N-2903-3-1	122	85	25	0.518	0.392	2013	**6.7**	0.105
						2015	2.4	
						2017	1.53	
Merced Community College N-2903-4-1	122	85	25	0.518	0.392	2013	**7.5**	0.118
						2015	0.18	
						2017	2.27	
Yosemite Union High School C-1801-4-2	122	90	11	0.499	0.173	2012	7.4	0.117
						2014	0.1	
						2016	1.2	
Yosemite Union High School C-1801-5-1	122	90	11	0.499	0.173	2013	**4.0**	0.063
						2015	4.0	
						2017	2.4	
Pacific Choice Brands C-906-9-1	197	140	5	0.67	0.08	2011	0.3	0.088*
						2013	0.5	
						2016	**5.4**[8]	
Super Store Industries N-3232-5-1	379	280	9	0.31824	0.241	2014	0.3	0.053
						2016	1.65	
						2018	**1.98**	
Super Store Industries N-3232-6-1	379	280	9	0.31824	0.241	2014	0.54	0.054
						2016	1.59	
						2018	**2.01**	

[8] Unit C-906-9-1 failed its 2016 source test for NOx

NO_X Data for Engines Used for Power Generation With a Heat Recovery System

Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted NO_X Limit (ppmv at 15% O_2)	Heat Recovered-Design Value (MMBtu/hr)	lb-NO_X/MW-hr (based on permitted NO_X limit, with heat recovery)	NO_X Source Test data (ppmv at 15% O_2)		lb-NO_X/MW-hr (based on highest NO_X source test result, with heat recovery)
						Year	Result	
Super Store Industries N-3232-7-1	379	280	9	0.31824	0.241	2014	1.57	0.080
						2016	**3.01**	
						2018	2.31	
Super Store Industries N-3232-8-1	379	280	9	0.31824	0.241	2014	**2.99**	0.080
						2016	1.04	
						2018	1.3	
Calamco Cogen N-7082-3-0	566	375	6	0.578	0.209	2014	2	0.115
						2016	**3.3**	
						2018	1.4	
County of Tulare S-1609-4-1	1,049	759	9	2.0	0.101	2011	1.35	0.056
						2012	**5**	
						2013	4.26	
Western Co-Gen C-4161-1-3	1,529	1,140	9	2.41	0.122	2010	1.9	0.070
						2011	**5.2**	
						2012	2.6	
Western Co-Gen C-4161-2-3	1,529	1,140	9	2.41	0.122	2013	1.7	0.062
						2014	0.6	
						2015	**4.6**	
Fresno County Maintenance C-1629-6-1	1,737	1,250	5	2.57	0.103	2013	**3.7**	0.076
						2014	3	
						2015	2.7	
Hilmar Cheese Turlock N-9141-3-1	3,681	2,652	5	8.542	0.082	2016	2	0.044
						2018	**2.7**	
Hilmar Cheese Turlock N-9141-4-1	3,681	2,652	5	8.542	0.082	2016	2	0.051
						2018	**3.1**	
Super Store Industries N-3232-7-1	379	280	9	0.31824	0.241	2014	1.57	0.080
						2016	**3.01**	
						2018	2.31	
Super Store Industries N-3232-8-1	379	280	9	0.31824	0.241	2014	**2.99**	0.080
						2016	1.04	
						2018	1.3	
Calamco Cogen N-7082-3-0	566	375	6	0.578	0.209	2014	2	0.115
						2016	**3.3**	
						2018	1.4	
County of Tulare S-1609-4-1	1,049	759	9	2.0	0.101	2011	1.35	0.056
						2012	**5**	
						2013	4.26	
Western Co-Gen C-4161-1-3	1,529	1,140	9	2.41	0.122	2010	1.9	0.070
						2011	**5.2**	
						2012	2.6	
Western Co-Gen C-4161-2-3	1,529	1,140	9	2.41	0.122	2013	1.7	0.062
						2014	0.6	
						2015	**4.6**	
Fresno County Maintenance C-1629-6-1	1,737	1,250	5	2.57	0.103	2013	**3.7**	0.076
						2014	3	
						2015	2.7	
Hilmar Cheese Turlock N-9141-3-1	3,681	2,652	5	8.542	0.082	2016	2	0.044
						2018	**2.7**	

NOx Data for Engines Used for Power Generation With a Heat Recovery System								
Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted NOx Limit (ppmv at 15% O_2)	Heat Recovered-Design Value (MMBtu/hr)	lb-NOx/MW-hr (based on permitted NOx limit, with heat recovery)	NOx Source Test data (ppmv at 15% O_2)		lb-NOx/MW-hr (based on highest NOx source test result, with heat recovery)
						Year	Result	
Hilmar Cheese Turlock N-9141-4-1	3,681	2,652	5	8.542	0.082	2016	2	0.051
						2018	**3.1**	

NOx Data for Engines Used for Power Generation Without a Heat Recovery System							
Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted NOx Limit (ppmv at 15% O_2)	lb-NOx/MW-hr (based on permitted limit)	NOx Source Test data (ppmv at 15% O_2)		lb-NOx/MW-hr (based on highest source test result)
					Year	Result	
California Power Holdings C-3775-1-9	4,157	3,100	9	0.207	2013	5.26	0.170
					2015	**7.4**	
					2017	4.7	
California Power Holdings C-3775-2-9	4,157	3,100	9	0.207	2013	2.56	0.103
					2015	2.1	
					2017	**4.5**	
California Power Holdings C-3775-3-9	4,157	3,100	9	0.207	2013	**6.34**	0.146
					2015	3.4	
					2017	4.4	
California Power Holdings C-3775-4-9	4,157	3,100	9	0.207	2013	7.12	0.165
					2015	5.7	
					2017	**7.2**	
California Power Holdings C-3775-5-9	4,157	3,100	9	0.207	2013	**7.3**	0.168
					2015	3.7	
					2017	6.6	
California Power Holdings C-3775-6-9	4,157	3,100	9	0.207	2013	4.85	0.154
					2015	**6.7**	
					2017	6.3	
California Power Holdings C-3775-7-9	4,157	3,100	9	0.207	2013	6.88	0.205
					2015	4.9	
					2017	**8.9**	
California Power Holdings C-3775-8-9	4,157	3,100	9	0.207	2013	6.64	0.186
					2015	**8.1**	
					2017	5.1	
California Power Holdings C-3775-9-9	4,157	3,100	9	0.207	2013	5.01	0.156
					2015	**6.8**	
					2017	6.7	
California Power Holdings C-3775-10-9	4,157	3,100	9	0.207	2013	6.15	0.198
					2015	**7.4**	
					2017	8.6	
California Power Holdings C-3775-11-9	4,157	3,100	9	0.207	2013	5.64	0.140
					2015	2.3	
					2017	**6.1**	
California Power Holdings C-3775-12-9	4,157	3,100	9	0.207	2013	**5.91**	0.136
					2015	2.1	
					2017	3.8	
California Power Holdings C-3775-13-9	4,157	3,100	9	0.207	2013	5.17	0.140
					2015	4.3	
					2017	**6.1**	

NO_X Data for Engines Used for Power Generation Without a Heat Recovery System							
Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted NO_X Limit (ppmv at 15% O_2)	lb-NO_X/MW-hr (based on permitted limit)	NO_X Source Test data (ppmv at 15% O_2) Year	Result	lb-NO_X/MW-hr (based on highest source test result)
California Power Holdings C-3775-14-9	4,157	3,100	9	0.207	2013	**6.33**	0.145
					2015	2.7	
					2017	3.2	
California Power Holdings C-3775-15-9	4,157	3,100	9	0.207	2013	5.46	0.184
					2015	**8**	
					2017	4.3	
California Power Holdings C-3775-16-9	4,157	3,100	9	0.207	2013	**4.89**	0.112
					2015	4.4	
					2017	4.3	
Modesto Irrigation District N-3233-6-3	11,667	8,440	5	0.157	2016	3.4	0.110
					2017	**3.5**	
					2018	3.2	
Modesto Irrigation District N-3233-7-3	11,667	8,440	5	0.157	2016	3.2	0.110
					2017	1.6	
					2018	**3.5**	
Modesto Irrigation District N-3233-8-3	11,667	8,440	5	0.157	2016	2.7	0.110
					2017	**3.5**	
					2018	2.6	
Modesto Irrigation District N-3233-9-3	11,667	8,440	5	0.157	2016	3.4	0.113
					2017	3.3	
					2018	**3.6**	
Modesto Irrigation District N-3233-10-3	11,667	8,440	5	0.157	2016	3.4	0.110
					2017	3.4	
					2018	**3.5**	
Modesto Irrigation District N-3233-11-3	11,667	8,440	5	0.157	2016	3.5	0.113
					2017	1.8	
					2018	**3.6**	

Based on an extensive review of California air district rules and BACT guidelines, and a survey of source tests for IC engines permitted in the District, the following NO_X control options were identified:

<u>NO_X Control Option #1: 5 ppmvd NO_X @ 15% O_2 or 0.07 g-NO_X/bhp-hr</u>

This option is based upon the District's previous Achieved-in Practice BACT Guideline requirements and has been achieved by multiple units within the District for sufficient time demonstrating ongoing feasibility.

<u>NO_X Control Option #2: 0.070 lb-NO_X/MW-hr</u>

This option is based on South Coast AQMD Rule 1110.2 and the SCAQMD BACT requirements for IC engines installed after February 1, 2008 that are used for non-emergency electrical generation. The emission level of this NO_X option is equivalent to the NO_X emission level required by the California Air Resources Board's Distributed Generation Certification Regulation for this type of equipment, which applies to units that do not require permits from California air Districts. Several units operating within the District have source tested at levels that achieve the 0.070 lb-NO_X/MW-hr limit.

South Coast AQMD Rule 1110.2 allows operators of IC engines used to generate both heat and electric power to demonstrate compliance with the NO_X emissions standard of 0.070 lb/MW-hr by taking credit for the recovered thermal energy of one MW-hr for each 3.4 million Btus of heat recovered.

Based on data obtained for the permitted IC engines operating within SJVAPCD, the 0.070 lb-NO_X/MW-hr limit is approximately equivalent to:

- 4 ppmvd NO_X @ 15% O_2 for units with heat recovery
- 2.5 ppmvd NO_X @ 15% O_2 for units without heat recovery

Furthermore, South Coast Rule 1110.2 indicates that 2.5 ppmvd NO_X @ 15% O_2 complies with the 0.070 lb-NO_X/MW-hr limit for units without heat recovery.

For the proposed 1,966 bhp IC engine powering a 1,429 kW electrical generator, 0.070 lb-NO_X/MW-hr is calculated to be equivalent to the following:

bhp Rating: 1,966 bhp
Electrical Production: 1,429 kW_e ÷ 1,000 kW_e/MW_e = 1.429 MW_e
Heat Recovery: 5.4 MMBtu/hr ÷ (3.4 MMBtu/hr)/MW_{th} = 1.588 MW_{th}
Engine Efficiency: 36%

(1.429 MW_e + 1.588 MW_{th}) x 0.070 lb-NO_X/MW-hr = 0.2112 lb-NO_X/hr

0.2112 lb-NO_X/hr x 453.59 g/lb ÷ 1,966 bhp = 0.049 g-NO_X/bhp-hr

<u>NO_X Control Option #3: 2 ppmvd NO_X @ 15% O_2 Natural Gas-Fired Turbine</u>

This option was listed as Alternate Basic Equipment basic equipment in the District's previous BACT Guideline 3.3.12, but is generally only applicable to projects that produce more than 3 MW of electricity, as discussed below.

<u>NO_X Control Option #4: Electric Motor (except for engines that will be used to generate electricity)</u>

This option was listed as Alternate Basic Equipment basic equipment in the District's previous BACT Guideline 3.3.12, but is not applicable for engines used to generate electricity.

<u>NO_X Control Option #5: Microturbine (< 9 ppmv NO_X @ 15% O_2)</u>

This option is listed as Alternate Basic Equipment basic equipment in the District's BACT Guideline 3.3.15 for digester gas-fired IC engines and through a technology transfer, will be considered for the engine when fired on natural gas.

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gas. Microturbines typically have electrical efficiencies of 25-30% based on the lower heating value (LHV) of the fuel, with larger microturbines usually having greater efficiencies than smaller microturbines. Microturbine manufacturers include Capstone Green Energy and FlexEnergy Solutions.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_X, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_X (DLN)) combustion technology. Microturbine manufacturers will generally guarantee NO_X emissions of 9 ppmv @ 15% O_2 for microturbines. However, emission tests performed on biogas-fired microturbines have demonstrated lower emissions.

The proposed project is for a 1,429 kW natural gas and digester gas-fueled IC engine that will be used to produce combined heat and power for the operations at an existing winery and, although larger microturbines have recently become available, at least two microturbines packages with several individual microturbines would be required to replace the proposed IC engine. In addition, for previous projects that the District evaluated for the installation of digester gas-fired IC engines for power production, the applicants indicated that when they investigated microturbines as an alternative they found that there were difficulties related to the loss of power and efficiency because of heat de-rating in warmer climates and the very high pressure requirement and parasitic load, which increased overall costs. Although microturbines may not currently be a practical option for this particular project, they will be included as alternative equipment in the BACT analysis below.

<u>NO_X Control Option #6: Fuel Cell (≤ 0.05 lb- NO_X/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2)</u>

This option is listed as Alternate Basic Equipment basic equipment in the District's BACT Guideline 3.3.15 for digester gas-fired IC engines and through a technology transfer, will be considered for the engine when fired on natural gas.

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these fuel cells, which operate at high temperatures, are tolerant of CO_2 that is found biogas.

Fuel cells offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells has been the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense, the cost of periodic replacement of the fuel cell stack, and, for biogas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, biogas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas, such as landfill gas and brewery wastewater gas.

b. Step 2 - Eliminate technologically infeasible options

<u>NO_X Control Option #3: 2 ppmvd NO_X @ 15% O_2 Natural Gas-Fired Turbine (Alternate Basic Equipment)</u>

Option 3, Natural Gas-Fired Turbine with 2 ppmvd NO_X @ 15% O_2, was determined to be infeasible for the proposed project because the proposed project would require a natural gas-fired turbine rated approximately 1,429 kWe and natural gas-fired turbines rated less than 3 MW typically are not capable of consistently complying with a NO_X emission limit of 2 ppmv @ 15% O_2, but are generally permitted or certified to comply with higher NO_X emission rates. In addition, the available information indicates that the principal suppliers of gas turbines are not currently actively marketing gas turbines for used for electrical generation rated less than 3 MW because this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

Because the proposed project would require a gas turbine rated less than 3 MW, which would not be able to consistently comply with a NO_X emission limit of 2 ppmv @ 15% O_2, a natural gas-fired turbine with NO_X emissions of 2 ppmv @ 15% O_2 is not considered feasible for this particular project and will be eliminated from consideration. However, the NO_X emission limit that the applicant has proposed for the engine when fueled with natural gas, 0.049 g-NOx/bhp-hr (equivalent to 4.1 ppmvd NOx @ 15% O_2), is expected to be no greater than the NO_X emission limit that would be achieved by a comparably sized gas turbine.

<u>NO_X Control Option #4: Electric Motor (except for engines that will be used to generate electricity) (Alternate Basic Equipment)</u>

Option 4, Electric Motor, is not feasible for the project since the proposed engine will be used to generate electric power; therefore, this option will be eliminated from consideration.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (0.05 lb- NO_X/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2)

2) 0.070 lb-NO_X/MW-hr* (approximately 2.5 ppmvd NO_X @ 15% O_2 for units without heat recovery and 4 ppmv NO_X @ 15% O_2 for units with heat recovery) (based on SCAQMD Rule 1110.2 - Achieved in Practice)

   *When determining compliance with the lb/MW-hr NO_X requirement, engines with heat recovery may include up to one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr) in addition to each MW-hr of net electricity produced ($MW_{e\text{-}hr}$)

3) 0.07 g-NO_X/bhp-hr or 5 ppmvd NO_X @ 15% O_2 (Achieved in Practice)

4) Microturbine (9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Because fuel cells result in reduced NO_X, CO, and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis demonstrates that replacement of the proposed engine with a fuel cell is not cost effective even when the additional operation costs of a fuel cell are not considered.

Assumptions

- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,412.14 Btu/kW-hr
- The initial capital costs and the operation costs for the natural gas-fueled IC engine and fuel cells will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[13] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][14]
- Price for electricity: $30/MW-hr (based on the current Net Surplus Compensation[9])

[9] See the California Public Utilities Commission (CPUC) webpage at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering.

Assumptions for the Proposed Natural Gas/Digester Gas-Fired IC Engine (ATC N-1237-892-0) when fueled with Natural Gas

- The IC engine will operate at up to full load for 24 hour/day and 8,400 hour/year (applicant's proposal)

- Higher Heating Value (hhv) efficiency for the IC engine: 35% (assumed based on information from the engine supplier)

- The maximum daily total heating value of the natural gas used to fuel the engine will be: 343.1 MMBtu/day (*1,966* bhp_{out} *x 1* bhp_{in}*/0.35* bhp_{out} *x 2,545* Btu_{in}/bhp_{in}*-hr x 1 MMBtu/*10^6 *Btu x 24 hr/day*)

- The maximum annual total heating value for of the natural gas used by the engine will be: 120,083.3 MMBtu/year (*1,966* bhp_{out} *x 1* bhp_{in}*/0.35* bhp_{out} *x 2,545* Btu_{in}/bhp_{in}*-hr x 1 MMBtu/*10^6 *Btu x 8,400 hr/year*)

- Estimated purchase and installation cost for CHP IC engine producing approximately 1,429 kWe without add-on air pollution control equipment: $1,891/kW (*Average of interpolated costs from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 based on US Consumer Price Index (CPI) Inflation Calculator*)

- Estimated operation costs for CHP IC engine that can produce 1,429 kWe without add-on air pollution control costs: $0.022/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 based on US CPI Inflation Calculator*)

- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 11 ppmv @ 15% O_2 = 0.0427 lb/MMBtu

- Rule 4702 CO emission limit for non-agricultural, lean burn IC engines: 2,000 ppmv @ 15% O_2 as CH_4 = 4.72 lb/MMBtu

- 40 CFR 60 Subpart JJJJ CO emission limit for natural gas-fired IC engines: 5.0 g/bhp-hr (or 610 ppmv @ 15% O_2)

- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% O_2 as CH_4 = 1.012 lb/MMBtu

- 40 CFR 60 Subpart JJJJ VOC emission limit for natural gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane)

Assumptions for Fuel Cell System

- Net electrical hhv efficiency for a fuel cell: 49% (2016-2017 Self Generation Incentive Program Impact Evaluation[10] (September 28, 2018) submitted to the Pacific Gas and Electric Company SGIP Working Group reports lower heating value (LHV) efficiencies for Fuel Cells used only for electrical generation of 54% in 2016 and 55% in 2017. This results in an average LHV efficiency of 54.5% for 2016-2017 and an estimated average higher heating value (HHV) efficiency of 49% for 2014-2015)

- Size of fuel cell system needed to replace the proposed 1,429 kWe IC engine: 2,100 kW (estimated based on 343.1 MMBtu/day and 49% efficiency)

- Estimated Purchase and Installation Cost for a 2,100 kW Molten Carbonate Fuel Cell: $5,266/kW (*Average of values for largest fuel cells from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 dollars based on CPI Inflation Calculator; Note: the U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 10-21-2016 and available at: http://www.wbdg.org/resources/fuelcell.php) states, "Installation costs of a fuel cell system can range from $5,000/kW to $10,000/kW." Therefore, this estimate falls within the expected range and is below recently reported costs for some fuel cells.*)

- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: $0.047/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 dollars based on CPI inflation calculator*)

- Fuel Cell NO_X emissions: 0.01 - 0.02 lb/MW-hr *(Note: Fuel cells have been certified to the ARB Distributed Generation Certification level of 0.07 lb-NO_X/MW-hr but measured emissions from fuel cells are generally much lower)*

- Fuel Cell CO emissions: 0.10 lb-CO/MW-hr (Based on ARB Distributed Generation Certification level and emission tests on fuel cells)

- Fuel Cell VOC emissions: 0.02 lb-VOC/MW-hr (≤ 2.0 ppmv VOC @ 15% O_2 as CH_4 based on ARB Distributed Generation Certification level and emission tests on fuel cells)

[10] Self Generation Incentive Program Impact Evaluation (September 28, 2018) Prepared by Itron, submitted to the Pacific Gas and Electric Company SGIP Working Group, Section 4 – Generation Project Energy Impacts, Figure 4-34 - 2017 Overall and Component LHV Efficiencies by Technology. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program/self-generation-incentive-program-evaluation-reports

Capital Cost

The estimated increased incremental capital cost for replacement of the proposed IC engine with fuel cells is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engine.

The incremental capital cost for replacement of the proposed IC engine with a fuel cell power plant is calculated as follows:

(2,100 kW x $5,266/kW) - (1,429 kW x $1,891/kW) = $8,356,361

Annualized Capital Cost

Pursuant to District Policy APR 1305, Section X (dated June 1, 2021), which was in effect at the time that the application for this project was deemed complete, the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 4% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^{n}]/[(I+1)^{n}-1]$$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (4%)
N = Equipment Life (10 years)

$$A = [\$8,356,361 \times 0.04(1.04)^{10}]/[(1.04)^{10}-1]$$
$$= \mathbf{\$1,027,832/year}$$

Annual Costs

Electricity Generated
The amount of electricity potentially generated by each option is calculated as follows:

Proposed IC Engine Producing 1,429 kWe
1,429 kWe x 8,400 hr/yr = 12,003,600 kW-hr/year

Fuel Cells (Alternate Equipment)
343.1 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,412.14 Btu x 0.49 (electrical efficiency) = 2,053 kWe

120,083.3 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,412.14 Btu x 0.49 (electrical efficiency) = 17,244,549 kW-hr/year

Cost (Decrease) from Increased Revenue for Power Generation from Replacing the Proposed 1,429 kW Engine with a Fuel Cell System
(12,003,600 kW-hr/yr - 17,244,549 kW-hr/yr) x 1 MW/1,000 kW x $30/MW-hr = -$157,228/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Proposed IC Engine Producing 1,429 kWe
12,003,600 kW-hr/yr x $0.022/kW-hr = $264,079/year

Fuel Cells (Alternate Equipment)
17,244,549 kW-hr/yr x $0.047/kW-hr = $810,494/year

Annual Costs of Increased Maintenance
$810,494/yr - $264,079/yr = $546,415/year

Total Increased Annual Costs for Fuel Cell as an Alternative to Proposed IC Engine
$1,027,832/year + (-$157,228/year) + $546,415/year = **$1,417,019/year**

Emission Reductions:

NO_X, CO, and VOC Emission Factors:

Pursuant to the District's Policy APR 1305 (dated June 1, 2021), which was in effect at the time that he application for this project was deemed complete, District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the IC engine will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.2, Table 2, 2.e. The District Standard Emissions for CO and VOC emissions from the engines will be based on the New Source Performance Standard (NSPS) CO and VOC emission limits for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since these limits are applicable and are more representative of the emissions than the current applicable CO and VOC emission limits of District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions:
NO_X: 0.0427 lb-NO_X/MMBtu (11 ppmv NO_X @ 15% O_2)
CO: 5.0 g-CO/bhp-hr
VOC: 1.0 g-VOC/bhp-hr

Emissions from Fuel Cells as Alternative Equipment:
NO_X: 0.01 lb-NO_X/MW-hr
CO: 0.10 lb-NO_X/MW-hr

VOC: 0.02 lb-VOC/MW-hr

Emission Reductions:

Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO_X Emission Reductions (11 ppmv NO_X @ 15% O_2 → 0.01 lb-NO_X/MW-hr)
(120,083.3 MMBtu/yr x 0.0427 lb-NO_X/MMBtu) – (17,244,549 kW-hr/yr x 1 MW/1,000 kW x 0.01 lb-NO_X/MW-hr)
= 4,955 lb-NO_X/year (2.478 ton-NO_X/year)

CO Emission Reductions (5.0 g-CO/bhp-hr → 0.10 lb-CO/MW-hr)
(1,966 bhp x 8,400 hr/yr x 5.0 g-CO/bhp-hr x 1 lb/453.59 g) – (17,244,549 kW-hr/yr x 1 MW/1,000 kW x 0.10 lb-CO/MW-hr)
= 180,317 lb-CO/year (90.158 ton-CO/year)

VOC Emission Reductions (1.0 g-VOC/bhp-hr → 0.02 lb-VOC/MW-hr)
(1,966 bhp x 8,400 hr/yr x 1.0 g-VOC/bhp-hr x 1 lb/453.59 g) – (17,244,549 kW-hr/yr x 1 MW/1,000 kW x 0.02 lb-VOC/MW-hr)
= 36,063 lb-VOC/year (18.032 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Threshold (MCET) for NO_X, CO, and VOC Reductions based on District Standard Emission Reductions

Multi-Pollutant Cost Effectiveness Threshold (MCET) for the NO_X, CO, and VOC reductions from replacing the proposed IC engine with fuel cells is calculated below using the cost effectiveness thresholds from the District's Revised BACT Cost Effectiveness Thresholds Memo, dated May 14, 2008.

(2.478 ton-NO_X/year x \$31,600/ton-NO_X) + (90.158 ton-CO/year x \$400/ton-CO) + (18.032 ton-VOC/year x \$22,600/ton-VOC)
= **\$521,891/year**

As shown above, the annualized capital cost of this alternate option exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO_X, CO, and VOC emission reductions. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: 0.070 lb-NO_X/MW-hr* (approximately 2.5 ppmvd NO_X @ 15% O_2 for units without heat recovery and 4 ppmv NO_X @ 15% O_2 for units with heat recovery) (Achieved in Practice)

Option 3: 0.07 g-NO_X/bhp-hr or 5 ppmvd NO_X @ 15% O_2 (Achieved in Practice)

Option 4: Microturbine (9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Additionally, the applicant has proposed an IC engine with NO_X emissions of 0.049 g-NOx/bhp-hr (equivalent to 4.1 ppmvd NOx @ 15% O_2 and 0.070 lb-NOx/MW-hr with credit for heat recovery) when it is fueled with natural gas. The NO_X emissions from the proposed IC engine when fueled with natural gas are less than or equal to the NO_X emissions achieved by these alternatives; therefore, these options do not need to be considered further and a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for NO_X emissions from the proposed engine when fueled with natural gas is NO_X emissions ≤ 0.049 g-NO_X/bhp-hr (equivalent to 0.070 lb-NOx/MW-hr with credit for heat recovery). The applicant has proposed IC engine with NO_X emissions ≤ 0.049 g-NO_X/bhp-hr. Therefore, the BACT requirements for NO_X will be satisfied.

2. BACT Analysis for PM_{10} Emissions:

a. Step 1 - Identify all control technologies

The District's most recent previous BACT guideline full-time fossil fuel-fired IC engines, District BACT Guideline 3.3.12, listed the following BACT requirements for PM_{10} from full-time fossil fuel-fired IC engines.

Previous SJVAPCD BACT Guideline 3.3.12 for Fossil Fuel-Fired IC Engines PM_{10} Emission Requirements		
Achieved in Practice	Technologically Feasible	Alternate Basic Equipment
1. For Compression Ignited Engines: 0.01 g-PM_{10}/bhp-hr 2. For Spark Ignited Engines: 0.06 g/bhp-hr (Total PM_{10})*	--	Electric Motor (except for engines that will be used to generate electricity)

* This total PM_{10} emission limit is based on EPA Method 5 (front half and back half) testing, which typically yields results as much as four times higher than when using the ISO 8178 Test Method. The ISO 8178 Test Method only reports filterable (i.e. front half) emissions.

In addition, the USA Environmental Protection Agency (USEPA) RACT/BACT/LAER, the California Air Resources Board (CARB) BACT Clearinghouse, and the South Coast Air

Quality Management District (SCAQMD), the Ventura County Air Pollution Control District (VCAPCD), the Bay Area Air Quality Management District (BAAQMD), and the Sacramento Metropolitan Air Quality Management District (SMAQMD) BACT Guidelines were reviewed to determine potential control technologies for this class and category of operation. The District also reviewed the applicable IC engine rules from BAAQMD and SCAQMD, and SMAQMD. The following table summarizes the results of the review of these BACT guidelines and air district rules:

BACT Requirement Source	Equipment Rating	PM_{10} Control Technology/Requirement
SCAQMD BACT Guidelines Part D IC Engine, Stationary, Non-Emergency, Electrical Generators (2-2-2018)	> 50 bhp	Utilization of a Clean Fuel in accordance with SCAQMD Policy in Part C Of SCAQMD BACT Guidelines (e.g. natural gas, liquid petroleum gas (LPG), hydrogen, and electricity) (12-02-2016) Compliance with SCAQMD Rule 1470 (12-02-2016) for stationary diesel IC engines (CARB diesel fuel and 0.01 g-PM_{10}/bhp-hr)
SCAQMD Rule 1110.2	New non-emergency Electrical Generators > 2/1/2008	No PM_{10} requirement listed
Sacramento Metropolitan AQMD BACT Determination 143 (Expired)	> 50 bhp	Uncontrolled natural gas combustion
Sacramento Metropolitan AQMD Rule 412	> 50 bhp	No PM_{10} requirement listed
Bay Area AQMD BACT Workbook Spark Ignition – Natural Gas Fired (Lean Burn)	≥ 50 bhp	Use of natural gas fuel
Bay Area AQMD BACT Workbook Spark Ignition, Natural Gas-Fired (Rich Burn)	≥ 50 bhp	Use of natural gas fuel
Bay Area AQMD BACT Workbook Internal Combustion Engine Stationary prime, Non-Agricultural (Compression Ignited)	> 50 bhp	0.01 g/bhp-hr
Bay Area AQMD Regulation 9, Rule 8	> 50 bhp	No PM_{10} requirement listed
Santa Barbara APCD (From CARB BACT Clearinghouse) ICE: 881 BHP Lean Burn IC Engine used for Cogeneration (2015)	N/A	No PM_{10} requirement listed
EPA New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart IIII	N/A	Tier 4 Final for compression ignition IC engines (0.015 g-PM_{10}/bhp-hr – 0.022 g-PM_{10}/bhp-hr)
EPA New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart JJJJ	N/A	No Standard
EPA National Emission Standards for Hazardous Air Pollutants (NESHAPS) 40 CFR Part 63 Subpart ZZZZ	N/A	No Standard

Additionally, the District reviewed information regarding PM_{10} emission factors for IC engines permitted within the District. However, because source testing of PM emissions has generally not been required for combustion of natural gas, there are very few source tests that confirm the permitted PM_{10} emission factors for natural gas-fired reciprocating IC engines. The PM_{10} emission factors used for permitting of natural gas-fired reciprocating IC engines in the District have typically been based on AP-42, Section 3.2 Natural Gas-fired Reciprocating Engines, assuming a 35% engine efficiency. The District also uses emission factors based on AP-42 for permitting natural gas-fired emergency IC engines in the Guideline for Expedited Application Review (GEAR) - 11.4 NG-Natural Gas-Fired Emergency/Emergency Standby IC Engines. The PM_{10} emission factors for natural gas-fired reciprocating IC engines based on AP-42, Section 3.2 Natural Gas-fired Reciprocating Engines (July 2000) are calculated below.

<u>PM_{10} Emission Factor for 4-Stroke Lean-Burn Engines Based on AP-42</u>

PM_{10} (filterable): 7.71 x 10^{-5}

PM (condensable): 9.91 x 10^{-3}

Total PM_{10}: 7.71 x 10^{-5} + 9.91 x 10^{-3} = 9.9871 x 10^{-3}

$$0.0099871\ \frac{\text{lb PM}_{10}}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.35\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp}-\text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.033\ \frac{\text{g PM}_{10}}{\text{bhp}-\text{hr}}$$

<u>PM_{10} Emission Factor for 4-Stroke Rich-Burn Engines Based on AP-42</u>

PM_{10} (filterable): 9.50 x 10^{-3}

PM (condensable): 9.91 x 10^{-3}

Total PM_{10}: 9.50 x 10^{-3} + 9.91 x 10^{-3} = 1.941 x 10^{-2}

$$0.01941\ \frac{\text{lb PM}_{10}}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1\ \text{Btu}_{\text{in}}}{0.35\ \text{Btu}_{\text{out}}} \times \frac{2{,}545\ \text{Btu}}{1\ \text{bhp}-\text{hr}} \times \frac{453.59\ \text{g}}{1\ \text{lb}} = 0.064\ \frac{\text{g PM}_{10}}{\text{bhp}-\text{hr}}$$

Examples of PM_{10} emission limits in District ATC permits and Permits to Operate (PTOs) for non-emergency natural gas-fired IC engines are shown in the following table.

Examples of PM_{10} Permit Limits for Non-Emergency Natural Gas-Fired IC Engines		
Facility Name and Permit Number	**Permit Limit for PM_{10}**	**Basis**
Lakeside Pipeline LLC ATC C-9441-2-1	0.06 g/bhp-hr	Project-Specific BACT Analysis
Lakeside Pipeline LLC ATC C-9441-3-1	0.06 g/bhp-hr	Project-Specific BACT Analysis

Examples of PM_{10} Permit Limits for Non-Emergency Natural Gas-Fired IC Engines		
Facility Name and Permit Number	**Permit Limit for PM_{10}**	**Basis**
Biorem Energy, LLC ATC C-9639-2-0	0.033 g/bhp-hr	AP-42
Biorem Energy, LLC ATC C-9639-3-0	0.033 g/bhp-hr	AP-42
Biorem Energy, LLC ATC C-9639-4-0	0.033 g/bhp-hr	AP-42
West Hills Community College District, PTO C-7970-1-1	0.063 g/bhp-hr	AP-42
West Hills Community College District, PTO C-7970-2-1	0.063 g/bhp-hr	AP-42
E & J Gallo Winery PTO N-1237-605-3	0.033 g/bhp-hr	AP-42
E & J Gallo Winery PTO N-1237-606-2	0.033 g/bhp-hr	AP-42
JP Oil Co Inc PTO S-8561-4-0	0.033 g/bhp-hr	AP-42

Based on the above data, the following PM_{10} control options were identified for compression-ignited and spark-ignited IC engines:

<u>PM_{10} Control Option #1</u>

- For Compression Ignited Engines: 0.01 g-PM_{10}/bhp-hr;
- For Lean-Burn Spark-Ignited Engines: 0.033 g-PM_{10}/bhp-hr
- For Rich-Burn Spark-Ignited Engines: 0.06 g-PM_{10}/bhp-hr

This option is based upon the District's previous Achieved-in-Practice BACT Guideline requirements and multiple units within the District have been permitted with these limits.

<u>PM_{10} Control Option #2: Electric Motor (except for engines that will be used to generate electricity)</u>

This option is was listed as Alternate Basic Equipment basic equipment in the District's previous BACT Guideline 3.3.12, but is not applicable for engines used to generate electricity.

b. Step 2 - Eliminate technologically infeasible options

<u>PM_{10} Control Option #2: Electric Motor (except for engines that will be used to generate electricity) (Alternate Basic Equipment)</u>

Option 2, Electric Motor, is not feasible for the project since the proposed engine will be used to generate electric power; therefore, this option will be eliminated from consideration.

c. Step 3 - Rank remaining options by control effectiveness

1) Use of an engine meeting the following limits (Achieved in Practice):
   - For Compression Ignited Engines: 0.01 g-PM_{10}/bhp-hr;
   - For Lean-Burn Spark-Ignited Engines: 0.033 g-PM_{10}/bhp-hr
   - For Rich-Burn Spark-Ignited Engines: 0.06 g-PM_{10}/bhp-hr

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the highest ranked control option identified above and this option has been determined to be achieved in practice. Therefore, this option is required and a cost effectiveness analysis is not needed.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for PM_{10} emissions from the proposed lean-burn spark-ignited engine when fueled with natural gas is PM_{10} emissions ≤ 0.033 g-PM_{10}/bhp-hr. The applicant has proposed an IC engine with PM_{10} emissions ≤ 0.033 g-PM_{10}/bhp-hr. Therefore, the BACT requirements for PM_{10} will be satisfied.

3. BACT Analysis for CO Emissions:

a. Step 1 - List all control technologies

The District's most recent previous BACT guideline full-time fossil fuel-fired IC engines, District BACT Guideline 3.3.12, listed the following BACT requirements for CO from full-time fossil fuel-fired IC engines.

Previous SJVAPCD BACT Guideline 3.3.12 for Fossil Fuel-Fired IC Engines CO Emission Requirements		
Achieved in Practice	Technologically Feasible	Alternate Basic Equipment
1. For Compression Ignited Engines > 300 bhp and ≤ 500 bhp: 49 ppmvd @ 15% O_2 2. For Compression Ignited Engines > 500 bhp: 23 ppmvd @ 15% O_2 3. For Four-stroke Lean Burn Spark Ignited Engines > 500 bhp: 47 ppmvd @ 15% O_2 4. For all Engines rated ≥ 2,064 bhp: 33 ppmvd @ 15% O_2 5. For all other Engines (not included in categories 1 through 4 above): 56 ppmvd @ 15% O_2 or 0.6 g/bhp-hr	For all Compression Ignited Engines: 12 ppmvd @ 15% O_2 using an oxidation catalyst	Electric Motor (except for engines that will be used to generate electricity)

In addition, the USA Environmental Protection Agency (USEPA) RACT/BACT/LAER, the California Air Resources Board (CARB) BACT Clearinghouse, and the South Coast Air Quality Management District (SCAQMD), the Ventura County Air Pollution Control District (VCAPCD), the Bay Area Air Quality Management District (BAAQMD), and the Sacramento Metropolitan Air Quality Management District (SMAQMD) BACT Guidelines were reviewed to determine potential control technologies for this class and category of operation. The District also reviewed the applicable IC engine rules from BAAQMD and SCAQMD, and SMAQMD. The following table summarizes the results of the review of these BACT guidelines and air district rules:

BACT Guideline Source	Equipment Rating	CO Control Technology/Requirement
District Rule 4702	> 50 bhp	2,000 ppmvd @ 15% O_2
SCAQMD BACT Guidelines Part B - IC Engine, Stationary, Non-Emergency, Electrical Generators (2-5-2021)	147 bhp and 385 bhp	0.2 lb-CO/MW-hr (Tecogen Ultera Emissions Retrofit Kit control system, comprised of Three-Way Catalyst with Air/Fuel Ratio Controller and Oxidation Catalyst)
SCAQMD BACT Guidelines Part D IC Engine, Stationary, Non-Emergency, Electrical Generators (2-2-2018)	> 50 bhp	Compliance with SCAQMD Rule 1110.2 (2-2-2018)
SCAQMD Rule 1110.2	New non-emergency Electrical Generators > 2/1/2008	CO Emission Standard: 0.20 lb-CO/MW-hr *When determining compliance with the lb/MW-hr CO requirement, engines with heat recovery may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr) in addition to each MW-hr of net electricity produced (MW_{e-hr})
Sacramento Metropolitan AQMD BACT Determination 143 (Expired)	> 50 bhp	For four stroke lean burn engines >500 bhp, 47 ppmvd @ 15% O_2; For ≥ 2,064 bhp, 33 ppmvd @ 15% O_2
Sacramento Metropolitan AQMD Rule 412	> 50 bhp	4,000 ppmv @ 15% O_2
Bay Area AQMD BACT Workbook Spark Ignition – Natural Gas Fired (Lean Burn)	≥ 50 bhp	<u>Achieved in Practice</u> 0.60 g/bhp-hr (74 ppmv @ 15% O_2) <u>Technologically Feasible</u> 0.10 g/bhp-hr (12 ppmv @ 15% O_2)
Bay Area AQMD BACT Workbook Spark Ignition, Natural Gas-Fired (Rich Burn)	≥ 50 bhp	<u>Achieved in Practice</u> 0.60 g/bhp-hr (56 ppmv @ 15% O_2)
Bay Area AQMD BACT Workbook Internal Combustion Engine Stationary prime, Non-Agricultural (Compression Ignited)	> 50 bhp	2.75 g/bhp-hr (319 ppmvd @ 155 O_2) (Achieved in Practice) 50% reduction of current Tier Standard (Technologically Feasible)

BACT Guideline Source	Equipment Rating	CO Control Technology/Requirement
Bay Area AQMD Regulation 9, Rule 8	> 50 bhp	<u>Lean Burn Engines</u> 2,000 ppmv @ 15% O_2 <u>Rich Burn Engines</u> 2,000 ppmv @ 15% O_2 <u>Compression Ignited Engines</u> 51 to 175 BHP: 4400 ppmv @ 15% O_2 > 175 BHP: 310 ppmv @ 15% O_2
Santa Barbara APCD (From CARB BACT Clearinghouse) ICE: 881 BHP Lean Burn IC Engine used for Cogeneration (2015)	N/A	0.450 g/bhp-hr
EPA New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart IIII	N/A	Compliance with Latest Tier Emission limits (Tier 4) 3.7 g/bhp-hr for Compression Ignited Engines rated less than 175 BHP 2.6 g/bhp-hr for Compression Ignited engines rated at 175 BHP and greater
EPA New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart JJJJ	N/A	Lean Burn Spark-ignited Engines: 2.0 g/bhp-hr, equal to 270 ppmvd @ 15% O_2 Rich Burn Spark Ignited Engines: 610 g/kw-hr
EPA National Emission Standards for Hazardous Air Pollutants (NESHAPS) 40 CFR Part 63 Subpart ZZZZ	N/A	Compression Ignited Engines rated equal to or greater than 100 BHP through 300 BHP: 230 ppmvd @ 15% O_2 Compression Ignited Engines rated greater than 300 bhp through 500 bhp: 49 ppmvd @ 15% O_2 or reduce CO emissions by at least 70 percent Compression Ignited Engines rated greater than 500 bhp: 23 ppmvd @ 15% O_2 or reduce CO emissions by at least 70 percent Two-stroke Lean Burn Engines rated greater than 100 BHP through 500 BHP: 225 ppmvd @ 15% O_2. Four-stroke Lean Burn Engines rated greater than 500 BHP: 47 ppmvd CO @ 15% O_2 or reduce CO emissions by at least 93% Four-stroke Rich Burn Engines rated greater than 500 bhp: 270 ppmvd CO @ 15% O_2 or reduce CO by at least 75%.

Additionally, the District performed a detailed survey and review of IC engines permitted within the District that are used for electric power generation. The following survey is divided into two subcategories:

- **First Table:** IC engines with heat recovery
- **Second Table:** IC engines without heat recovery

For cogeneration units with a heat recovery system, the quantity of heat recovered was determined either from the manufacturer's data provided in the original permitting action, or from information that was provided by the facility for previous analyses.

As part of the industry survey, the District reviewed up to three recent emissions source tests to gather the CO emissions data for each engine. The following tables summarize the Districts review of CO emissions from permitted engines used for power generation.

NOTE:

For each table below:

Green Highlight	IC Engine Achieves 0.20 lb-CO/MW-hr or less
Red Highlight	IC Engine Does not Achieve 0.20 lb-CO/MW-hr

CO Data for Engines Used for Power Generation With a Heat Recovery System

Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted CO Limit (ppmv at 15% O_2)	Heat Recovered -Design Value (MMBtu/hr)	lb-CO/MW-hr (based on permitted CO limit, with heat recovery)	CO Source Test data (ppmv at 15% O_2)		lb-CO/MW-hr (based on highest CO source test result, with heat recovery)
						Year	Result	
Atwater High N-1306-2-2	86	60	68	0.44	0.612	2013	37.6	0.480
						2015	**53.4**	
						2017	24.3	
Ripon Unified N-686-3-0	122	60	70	0.366	0.734	2014	6.84	0.083
						2016	**7.9**	
Sanger Unified C-3563-11-1	86	60	70	0.44	0.628	2013	26.4	0.295
						2015	**32.8**	
						2017	4.5	
Sanger Unified C-3563-12-1	86	60	70	0.44	0.628	2013	**52**	0.468
						2015	51.8	
						2017	51.8	
Sanger Unified C-7162-3-0	122	60	70	0.366	0.734	2012	**32**	0.336
						2014	13	
						2016	6.2	
Sanger Unified C-7162-4-0	122	60	70	0.366	0.734	2012	8.7	0.174
						2014	10.3	
						2016	**16.6**	
Dynatect Ro-Lab Inc. N-704-10-0	108	75	70	0.49	0.643	2014	8.8	0.263
						2016	**28.6**	
						2018	25.6	
Dynatect Ro-Lab Inc N-704-11-0	108	75	70	0.49	0.643	2014	38.9	0.468
						2016	23.9	
						2018	**47.3**	
Yosemite Union High School C-1801-4-2	122	90	300	0.499	2.88	2012	**78.4**	0.753
						2014	19.8	
						2016	9.1	
Yosemite Union High School	122	90	300	0.499	2.88	2013	148	1.666
						2015	**173.5**	

CO Data for Engines Used for Power Generation With a Heat Recovery System								
Facility and Permit Unit	**bhp Rating**	**Generator Rating (kW)**	**Permitted CO Limit (ppmv at 15% O_2)**	**Heat Recovered -Design Value (MMBtu/hr)**	**lb-CO/MW-hr (based on permitted CO limit, with heat recovery)**	**CO Source Test data (ppmv at 15% O_2) Year**	**Result**	**lb-CO/MW-hr (based on highest CO source test result, with heat recovery)**
C-1801-5-1						2017	57.6	
Pacific Choice Brands C-906-9-1	197	140	70	0.67	0.694	2011	0.3	0.115
						2013	1.4	
						2016	**11.6**	
Super Store Industries N-3232-5-1	379	280	56	0.31824	0.907	2014	**15.57**	0.252
						2016	3.71	
						2018	4.7	
Super Store Industries N-3232-6-1	379	280	56	0.31824	0.907	2014	**16.11**	0.261
						2016	3.33	
						2018	2.66	
Super Store Industries N-3232-7-1	379	280	56	0.31824	0.907	2014	2.19	0.156
						2016	2.47	
						2018	**9.65**	
Super Store Industries N-3232-8-1	379	280	56	0.31824	0.907	2014	6.8	0.152
						2016	**9.39**	
						2018	3.41	
Calamco Cogen N-7082-3-0	566	375	68	0.578	1.439	2014	38.3	1.134
						2016	**53.6**	
						2018	53.3	
County of Tulare S-1609-4-1	1049	759	56	2	0.382	2011	13.56	0.095
						2012	**14**	
						2013	9.33	
Western Co-Gen C-4161-1-3	1529	1140	68	2.41	0.559	2010	27.1	0.366
						2011	43.3	
						2012	**44.5**	
Western Co-Gen C-4161-2-3	1529	1140	68	2.41	0.559	2013	49.3	0.466
						2014	51.3	
						2015	**56.7**	
Fresno County Maintenance C-1629-6-1	1737	1250	50	2.57	0.625	2013	40.6	0.544
						2014	**43.5**	
						2015	41.2	
Hilmar Cheese Turlock N-9141-3-1	3681	2652	33	8.542	0.327	2016	0.6	0.007
						2018	**0.7**	
Hilmar Cheese Turlock N-9141-4-1	3681	2652	33	8.542	0.327	2016	1.1	0.012
						2018	**1.2**	

CO data for Engines Used for Power Generation Without a Heat Recovery System							
Facility and Permit Unit	**bhp Rating**	**Generator Rating (kW)**	**Permitted CO Limit (ppmv at 15% O_2)**	**Lb-CO/MW-hr (based on permitted limit)**	**CO Source Test data (ppmv at 15% O_2) Year**	**Result**	**lb-CO/MW-hr (based on highest source test result)**
California Power Holdings C-3775-1-9	4157	3100	20	0.413	2013	10.6	0.291
					2015	**14.1**	
					2017	1.4	
California Power Holdings C-3775-2-9	4157	3100	20	0.413	2013	7.1	0.264
					2015	**12.8**	
					2017	7.9	

CO data for Engines Used for Power Generation Without a Heat Recovery System							
Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted CO Limit (ppmv at 15% O_2)	Lb-CO/MW-hr (based on permitted limit)	CO Source Test data (ppmv at 15% O_2)		lb-CO/MW-hr (based on highest source test result)
					Year	Result	
California Power Holdings C-3775-3-9	4157	3100	20	0.413	2013	9.6	0.206
					2015	**10**	
					2017	3.9	
California Power Holdings C-3775-4-9	4157	3100	20	0.413	2013	13.4	0.301
					2015	5.7	
					2017	**14.6**	
California Power Holdings C-3775-5-9	4157	3100	20	0.413	2013	**14.6**	0.301
					2015	1.7	
					2017	10	
California Power Holdings C-3775-6-9	4157	3100	20	0.413	2013	**15.8**	0.326
					2015	8.6	
					2017	11.3	
California Power Holdings C-3775-7-9	4157	3100	20	0.413	2013	10.8	0.281
					2015	9.9	
					2017	**13.6**	
California Power Holdings C-3775-8-9	4157	3100	20	0.413	2013	11	0.256
					2015	12.3	
					2017	**12.4**	
California Power Holdings C-3775-9-9	4157	3100	20	0.413	2013	**15.5**	0.320
					2015	10.7	
					2017	13.9	
California Power Holdings C-3775-10-9	4157	3100	20	0.413	2013	**16.7**	0.345
					2015	14.8	
					2017	11.1	
California Power Holdings C-3775-11-9	4157	3100	20	0.413	2013	15.8	0.349
					2015	**16.9**	
					2017	3.8	
California Power Holdings C-3775-12-9	4157	3100	20	0.413	2013	9.1	0.318
					2015	9.4	
					2017	**15.4**	
California Power Holdings C-3775-13-9	4157	3100	20	0.413	2013	**14.2**	0.293
					2015	13.5	
					2017	7.8	
California Power Holdings C-3775-14-9	4157	3100	20	0.413	2013	13.8	0.297
					2015	**14.4**	
					2017	13.2	
California Power Holdings C-3775-15-9	4157	3100	20	0.413	2013	10.9	0.252
					2015	**11.5**	
					2017	12.2	
California Power Holdings C-3775-16-9	4157	3,100	20	0.413	2013	**14.3**	0.295
					2015	12.8	
					2017	13	
Modesto Irrigation District N-3233-6-3	11667	8,440	13	0.249	2016	3.7	0.092
					2017	4.1	
					2018	**4.8**	
Modesto Irrigation District N-3233-7-3	11667	8,440	13	0.249	2016	3.8	0.094
					2017	3.6	
					2018	**4.9**	
Modesto Irrigation District N-3233-8-3	11667	8,440	13	0.249	2016	4.1	0.096
					2017	4.3	
					2018	**5**	

CO data for Engines Used for Power Generation Without a Heat Recovery System							
Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted CO Limit (ppmv at 15% O_2)	Lb-CO/MW-hr (based on permitted limit)	CO Source Test data (ppmv at 15% O_2)		lb-CO/MW-hr (based on highest source test result)
					Year	Result	
Modesto Irrigation District N-3233-9-3	11667	8,440	13	0.249	2016	4.6	0.121
					2017	5.1	
					2018	**6.3**	
Modesto Irrigation District N-3233-10-3	11667	8,440	13	0.249	2016	4.3	0.103
					2017	4.4	
					2018	**5.4**	
Modesto Irrigation District N-3233-11-3	11667	8,440	13	0.249	2016	5.5	0.138
					2017	6.1	
					2018	**7.2**	

Based on an extensive review of California air district rules and BACT guidelines, and a survey of source tests for IC engines permitted in the District, the following CO control options were identified:

<u>CO Control Option #1</u>

- For Compression Ignited Engines > 300 bhp and < 500 bhp: 49 ppmvd @ 15 % O2;
- For Compression Ignited Engines > 500 bhp: 23 ppmvd @ 15% O2;
- For four-stroke lean burn spark-ignited engines > 500 bhp: 47 ppmvd @ 15% O2;
- For all engines ≥ 2,064 bhp: 33 ppmvd @ 15 %O2;
- For all other engines: 56 ppmvd @ 15% O2 or 0.6 g/bhp-hr

This option is based upon the District's previous Achieved-in-Practice BACT Guideline requirements and has been achieved by multiple units within the District.

<u>CO Control Option #2</u>

- For Compression Ignited Engines: 12 ppmvd CO @ 15 % O_2 using an oxidation catalyst

This option is based on the District's previous technologically feasible BACT Guideline requirements for full time compression ignited IC engines. No full-time compression ignited IC engines were identified in the District's survey of permitted units.

<u>CO Control Option #3 - 0.20 lb-CO/MW-hr</u>

This option is based on SCAQMD Rule 1110.2 and the SCAQMD BACT requirements for IC engines installed after February 1, 2008 that are used for non-emergency electrical generation.

South Coast AQMD Rule 1110.2 allows operators of IC engines used to generate both heat and electric power to demonstrate compliance with the CO emissions standard of 0.20 lb/MW-hr by taking credit for the recovered thermal energy at the of one MW-hr for each 3.4 million Btus of heat recovered.

Several of the units operating within the District have source tested at levels that achieve the 0.20 lb-CO/MW-hr limit of South Coast AQMD Rule 1110.2. Furthermore, South Coast AQMD provided the following list of engines powering electrical generators that are currently complying with Rule 1110.2 requirements.

Facility	Engine/Control Equipment	bhp	CO Emission Limit
Palm Springs City (Facility ID 42218)	Lean-Burn GE Jenbachher Model #JMS416B86 Engine with SCR	1,573	0.34 lb/MW_e-hr*
Play Capital Company (Facility ID 176353)	Rich Burn GE/Tecogen Model 7400 Engine with a 3-way catalyst	108	0.444 lb/MW_e-hr*
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #1: Rich-Burn Generac Model 6.8GNGD-100 Engine with a 3-way catalyst	147	0.20 lb/MW-hr
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #2: Rich-Burn Generac Model 6.8GNGD-100 Engine with a 3-way catalyst	147	0.20 lb/MW-hr
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #3: Rich-Burn Generac Model 6.8GNGD-130 Engine with a 3-way catalyst	189	0.20 lb/MW-hr
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #4: Rich-Burn Generac Model 6.8GNGD-130 Engine with a 3-way catalyst	189	0.20 lb/MW-hr
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #5: Rich-Burn Generac Model 13.3 GTA-250 Engine with a 3-way catalyst	385	0.20 lb/MW-hr
Coachillin' Holdings (Facility ID 187790)	Engine #1: Lean-Burn Mechanishe Werstatte Mannheim Model TCG-2016-V16 Engine with SCR and Oxidation Catalyst	1,107	0.43 lb/MW_e-hr*
Coachillin' Holdings (Facility ID 187790)	Engine #2: Lean-Burn Mechanishe Werstatte Mannheim Model TCG-2016-V16 Engine with SCR and Oxidation Catalyst	1,107	0.43 lb/MW_e-hr*

* This engine is complying with the overall SCAQMD Rule 1110.2 Rule limit of 0.20 lb-CO/MW-hr by using a thermal credit as specified in the Rule. SCAQMD used the quantity of heat recovered for this cogeneration system to calculate a lb-CO/MW_e-hr emission limit that is equivalent to the 0.20 lb-CO/MW-hr Rule limit.

Based on data from permitted engines operating within SJVAPCD, the 0.20 lb-CO/MW-hr limit is approximately equivalent to:

- 20 ppmvd @ 15% O_2 for units with heat recovery
- 12 ppmvd @ 15% O_2 for units without heat recovery

For the proposed 1,966 bhp IC engine powering a 1,429 kW electrical generator, 0.020 lb-CO/MW-hr is calculated to be equivalent to the following:

bhp Rating: 1,966 bhp
Electrical Production: 1,429 kW_e ÷ 1,000 kW_e/MW_e = 1.429 MW_e
Heat Recovery: 5.4 MMBtu/hr ÷ (3.4 MMBtu/hr)/MW_{th} = 1.588 MW_{th}
Engine Efficiency: 36%

(1.429 MW_e + 1.588 MW_{th}) x 0.020 lb-CO/MW-hr = 0.06034 lb-CO/hr

0.06034 lb-CO/hr x 453.59 g/lb ÷ 1,966 bhp = 0.014 g-CO/bhp-hr

CO Control Option #4: Electric Motor (except for engines that will be used to generate electricity)

This option is was listed as Alternate Basic Equipment basic equipment in the District's previous BACT Guideline 3.3.12, but is not applicable for engines used to generate electricity.

CO Control Option #5: Microturbine (< 60 ppmv CO @ 15% O_2)

This option is listed as Alternate Basic Equipment basic equipment in the District's BACT Guideline 3.3.15 for digester gas-fired IC engines and through a technology transfer, will be considered for the engine when fired on natural gas.

CO Control Option #6: Fuel Cell (≤ 0.10 lb-CO/MW-hr)

This option is listed as Alternate Basic Equipment basic equipment in the District's BACT Guideline 3.3.15 for digester gas-fired IC engines and through a technology transfer, will be considered for the engine when fired on natural gas.

b. Step 2 - Eliminate technologically infeasible options

CO Control Option #2 For Compression Ignited Engines: 12 ppmvd CO @ 15 % O_2 using an oxidation catalyst (Technologically Feasible for Compression Ignited Engines)

Control option #2 - 12 ppmvd CO @ 15 % O_2 using an oxidation catalyst for compression ignited IC engines is not applicable because the proposed IC engine is a spark ignited engine; therefore, this option will be removed from consideration for this BACT analysis.

CO Control Option #4: Electric Motor (except for engines that will be used to generate electricity) (Alternate Basic Equipment)

Option 2, Electric Motor, is not feasible for the project since the proposed engine will be used to generate electric power; therefore, this option will be eliminated from consideration.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.10 lb-CO/MW-hr) (Alternate Basic Equipment)

2) 0.020 lb-CO/MW-hr* (approximately 12 ppmvd CO @ 15% O_2 for units without heat recovery and 20 ppmv CO @ 15% O_2 for units with heat recovery) (based on SCAQMD Rule 1110.2 - Achieved in Practice)

*When determining compliance with the lb/MW-hr CO requirement, engines with heat recovery may include up to one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr) in addition to each MW-hr of net electricity produced ($MW_{e\text{-}hr}$)

3) CO emissions not exceeding the following limits (Achieved in Practice):
   - For Compression-Ignited Engines > 300 bhp and < 500 bhp: 49 ppmvd CO @ 15 % O_2;
   - For Compression-Ignited Engines > 500 bhp: 23 ppmvd CO @ 15% O_2;
   - For four-stroke lean-burn spark-ignited engines > 500 bhp: 47 ppmvd CO @ 15% O_2;
   - For all engines ≥ 2,064 bhp: 33 ppmvd CO @ 15 %O_2;
   - For all other engines: 56 ppmvd @ 15% O_2 or 0.6 g-CO/bhp-hr

4) Microturbine (≤ 0.10 lb-CO/MW-hr) (Alternate Basic Equipment)

d. Step 4 - Cost Effectiveness Analysis

<u>Option 1: Fuel Cell (≤ 0.10 lb-CO/MW-hr) (Alternate Basic Equipment)</u>

The multi-pollutant cost analysis performed above for the NO_X, CO, and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X, CO, and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

<u>Option 2: 0.020 lb-CO/MW-hr* (approximately 12 ppmvd CO @ 15% O_2 for units without heat recovery and 20 ppmv CO @ 15% O_2 for units with heat recovery) (Achieved in Practice)</u>

<u>Option 3: Microturbines (<60 ppmv CO @ 15% O_2) (Alternate Basic Equipment)</u>

The applicant has proposed an IC engine with CO emissions of 0.14 g-CO/bhp-hr (equivalent to 19.5 ppmvd CO @ 15% O_2) when it is fueled with natural gas. The CO emissions from the proposed IC engine when fueled with natural gas are less than or equal to the CO emissions achieved by this alternative; therefore, this option does not need to be considered further and a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for CO emissions from the proposed engine when fueled with natural gas is CO emissions ≤ 0.014 g-CO/bhp-hr (equivalent to 0.020 lb-CO/MW-hr with credit for heat recovery). The applicant has proposed IC engine with CO emissions ≤ 0.014 g-CO/bhp-hr. Therefore, the BACT requirements for CO will be satisfied.

4. BACT Analysis for VOC Emissions:

a. Step 1 - List all control technologies

The District's most recent previous BACT guideline full-time fossil fuel-fired IC engines, District BACT Guideline 3.3.12, listed the following BACT requirements for VOC from full-time fossil fuel-fired IC engines.

Previous SJVAPCD BACT Guideline 3.3.12 for Fossil Fuel-Fired IC Engines VOC Emission Requirements		
Achieved in Practice	Technologically Feasible	Alternate Basic Equipment
1. For all Compression Ignited engines: Use of an engine meeting the latest Tier standard 2. For all Spark Ignited engines: 25 ppmvd @ 15% O2 or 0.15 g/bhp-hr	1. For all Compression Ignited Engines: 50 percent reduction of latest Tier standard for VOC emissions using a catalytic oxidation system 2. For Rich Burn Spark Ignited engines: 12 ppmvd @ 15% O2 or 0.069 g/bhp-hr	Electric Motor (except for engines that will be used to generate electricity)

In addition, the USA Environmental Protection Agency (USEPA) RACT/BACT/LAER, the California Air Resources Board (CARB) BACT Clearinghouse, and the South Coast Air Quality Management District (SCAQMD), the Ventura County Air Pollution Control District (VCAPCD), the Bay Area Air Quality Management District (BAAQMD), and the Sacramento Metropolitan Air Quality Management District (SMAQMD) BACT Guidelines were reviewed to determine potential control technologies for this class and category of operation. The District also reviewed the applicable IC engine rules from BAAQMD and SCAQMD, and SMAQMD. The following table summarizes the results of the review of these BACT guidelines and air district rules:

BACT Guideline Source	Equipment Rating	VOC Control Technology/Requirement
District Rule 4702	> 50 bhp	750 ppmvd @ 15% O_2
SCAQMD BACT Guidelines Part B - IC Engine, Stationary, Non-Emergency, Electrical Generators (2-5-2021)	147 bhp and 385 bhp	0.1 lb-VOC/MW-hr (Tecogen Ultera Emissions Retrofit Kit control system, comprised of Three-Way Catalyst with Air/Fuel Ratio Controller and Oxidation Catalyst)
SCAQMD BACT Guidelines Part D IC Engine, Stationary, Non-Emergency, Electrical Generators (2-2-2018)	> 50 bhp	Compliance with SCAQMD Rule 1110.2 (2-2-2018)
SCAQMD Rule 1110.2	New non-emergency Electrical Generators > 2/1/2008	VOC Emission Standard: 0.10 lb-VOC/MW-hr *When determining compliance with the lb/MW-hr VOC requirement, engines with heat recovery may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr) in addition to each MW-hr of net electricity produced (MW_{e-hr})

BACT Guideline Source	Equipment Rating	VOC Control Technology/Requirement
Sacramento Metropolitan AQMD BACT Determination 143 (Expired)	> 50 bhp	25 ppmvd @ 15% O_2
Sacramento Metropolitan AQMD Rule 412	> 50 bhp	750 ppmv @ 15% O_2
Bay Area AQMD BACT Workbook Spark Ignition – Natural Gas Fired (Lean Burn)	≥ 50 bhp	<u>Achieved in Practice</u> 0.15 g/bhp-hr (32 ppmv @ 15% O_2)
Bay Area AQMD BACT Workbook Spark Ignition, Natural Gas-Fired (Rich Burn)	≥ 50 bhp	<u>Achieved in Practice</u> 0.15 g/bhp-hr (25 ppmv @ 15% O_2) <u>Technologically Feasible</u> 0.069 g/bhp-hr (12 ppmv @ 15% O_2)
Bay Area AQMD BACT Workbook Internal Combustion Engine Stationary prime, Non-Agricultural (Compression Ignited)	> 50 bhp	Latest Tier Standard (Achieved in Practice) 50% reduction of current Tier Standard (Technologically Feasible)
Bay Area AQMD Regulation 9, Rule 8	> 50 bhp	None
Santa Barbara APCD (From CARB BACT Clearinghouse) ICE: 881 BHP Lean Burn IC Engine used for Cogeneration (2015)	N/A	0.115 g/bhp-hr
EPA New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart IIII	N/A	Compliance with Latest Tier Emission limits (Tier 4) 3.5 g/bhp-hr (NOx + VOC) for Compression Ignited Engines rated between 50 BHP and 75 BHP 0.14 g-VOC/bhp-hr for Compression Ignited Engines rated at 75 BHP and greater
EPA New Source Performance Standards (NSPS) 40 CFR Part 60 Subpart JJJJ	N/A	0.7 g-VOC/bhp-hr or 60 ppmvd (as propane) @ 15% O_2
EPA National Emission Standards for Hazardous Air Pollutants (NESHAPS) 40 CFR Part 63 Subpart ZZZZ	N/A	None

Additionally, the District performed a detailed industry survey and review of IC engines permitted within the District that are used for electric power generation. The following survey is divided into two subcategories:

- **First Table:** IC engines with heat recovery
- **Second Table:** IC engines without heat recovery

For cogeneration units with a heat recovery system, the quantity of heat recovered was determined either from the manufacturer's data provided in the original permitting action, or from information that was provided by the facility for previous analyses.

As part of the industry survey, the District reviewed up to three recent emissions source tests to gather the VOC emissions data for each engine. The following tables summarize the Districts review of VOC emissions from permitted engines used for power generation.

NOTE:

For each table below:

Green Highlight	IC Engine Achieves 0.10 lb-VOC/MW-hr or less
Red Highlight	IC Engine Does not Achieve 0.10 lb-VOC/MW-hr

VOC Data for Engines Used for Power Generation With a Heat Recovery System

Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted VOC Limit (ppmv at 15% O_2)	Heat Recovered -Design Value (MMBtu/hr)	lb-VOC/MW-hr (based on permitted VOC limit, with heat recovery)	VOC Source Test data (ppmv at 15% O_2) Year	Result	lb-VOC/MW-hr (based on highest VOC source test result, with heat recovery)
Atwater High N-1306-2-2	86	60	30	0.44	0.153	2013	**0.05**	0.0003
Ripon Unified N-686-3-0	122	60	30	0.366	0.179	2014	**1.73**	0.0104
						2016	0.61	
Dynatect Ro-Lab Inc. N-704-10-0	108	75	30	0.49	0.16	2014	0.4	0.0389
						2016	0.504	
						2018	**7.4**	
Dynatect Ro-Lab Inc N-704-11-0	108	75	30	0.49	0.16	2014	0.66	0.0440
						2016	1.07	
						2018	**8.36**	
Valley Chrome Plating C-1318-7-1	108	75	25	0.49	0.132	2013	**0.99**	0.0052
						2015	0.9	
						2017	0.9	
Yosemite Union High School C-1801-4-2	122	90	34	0.499	0.186	2012	**3.4**	0.0187
						2014	0.2	
						2016	0.5	
Yosemite Union High School C-1801-5-1	122	90	34	0.499	0.186	2013	**2.2**	0.0121
						2015	0.5	
						2017	0.5	
Pacific Choice Brands C-906-9-1	197	140	30	0.67	0.169	2011	**0.3**	0.0017
						2013	0.3	
						2016	0.03	
Super Store Industries N-3232-5-1	379	280	25	0.31824	0.23	2014	0.88	0.0437
						2016	1.01	
						2018	**4.72**	
Super Store Industries N-3232-6-1	379	280	25	0.31824	0.23	2014	3.01	0.0374
						2016	**4.04**	
						2018	2.88	
Super Store Industries N-3232-7-1	379	280	25	0.31824	0.23	2014	0.31	0.0496
						2016	4.03	
						2018	**5.36**	
Super Store Industries N-3232-8-1	379	280	25	0.31824	0.23	2014	1.41	0.0182
						2016	**1.97**	
						2018	1.49	
County of Tulare S-1609-4-1	1049	759	30	2	0.117	2011	**5.13**	0.0200
						2012	0.21	
						2013	2.42	

VOC Data for Engines Used for Power Generation With a Heat Recovery System

Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted VOC Limit (ppmv at 15% O_2)	Heat Recovered -Design Value (MMBtu/hr)	lb-VOC/MW-hr (based on permitted VOC limit, with heat recovery)	VOC Source Test data (ppmv at 15% O_2) Year	Result	lb-VOC/MW-hr (based on highest VOC source test result, with heat recovery)
Western Co-Gen C-4161-1-3	1529	1140	25	2.41	0.117	2010	**15.1**	0.0709
						2011	10.8	
						2012	6.1	
Western Co-Gen C-4161-2-3	1529	1140	25	2.41	0.117	2013	4.4	0.0254
						2014	**5.4**	
						2015	1.02	
Fresno County Maintenance C-1629-6-1	1737	1250	25	2.57	0.178	2013	**45**[11]	0.3216[11]
						2014	2.7	
						2015	3.2	
Hilmar Cheese Turlock N-9141-3-1	3681	2652	25	8.542	0.142	2016	**2.8**	0.0159
						2018	1.9	
Hilmar Cheese Turlock N-9141-4-1	3681	2652	25	8.542	0.142	2016	2	0.0142
						2018	**2.5**	

VOC Data for Engines Used for Power Generation Without a Heat Recovery System

Facility and Permit Unit	bhp Rating	Generator Rating (kW)	Permitted VOC Limit (ppmv at 15% O_2)	lb-VOC/MW-hr (based on permitted limit)	VOC Source Test data (ppmv at 15% O_2) Year	Result	lb-VOC/MW-hr (based on highest source test result)
California Power Holdings C-3775-1-9	4157	3100	30	0.355	2013	0.5	0.0106
					2015	**0.9**	
					2017	0.5	
California Power Holdings C-3775-2-9	4157	3100	30	0.355	2013	0.5	0.0237
					2015	**2**	
					2017	0.5	
California Power Holdings C-3775-3-9	4157	3100	30	0.355	2013	**0.7**	0.0083
					2015	0.7	
					2017	0.5	
California Power Holdings C-3775-4-9	4157	3100	30	0.355	2013	0.49	0.0059
					2015	0.3	
					2017	**0.5**	
California Power Holdings C-3775-5-9	4157	3100	30	0.355	2013	**0.5**	0.0059
					2015	0.4	
					2017	0.5	
California Power Holdings C-3775-6-9	4157	3100	30	0.355	2013	0.5	0.0106
					2015	**0.9**	
					2017	0.5	
California Power Holdings C-3775-7-9	4157	3100	30	0.355	2013	0.91	0.0414
					2015	**3.5**	
					2017	0.5	
California Power Holdings C-3775-8-9	4157	3100	30	0.355	2013	0.51	0.2377
					2015	**20.1**	
					2017	0.5	
California Power Holdings C-3775-9-9	4157	3100	30	0.355	2013	0.97	0.0438
					2015	**3.7**	

[11] Unit C-1629-6-1 failed its 2013 source test for VOC

					2017	0.5	
California Power Holdings C-3775-10-9	4157	3100	30	0.355	2013	0.81	0.1963
					2015	**16.6**	
					2017	0.5	
California Power Holdings C-3775-11-9	4157	3100	30	0.355	2013	0.5	0.0449
					2015	**3.8**	
					2017	0.5	
California Power Holdings C-3775-12-9	4157	3100	30	0.355	2013	0.51	0.0154
					2015	**1.3**	
					2017	0.5	
California Power Holdings C-3775-13-9	4157	3100	30	0.355	2013	0.5	0.0083
					2015	**0.7**	
					2017	0.5	
California Power Holdings C-3775-14-9	4157	3100	30	0.355	2013	**0.81**	0.0096
					2015	0.3	
					2017	0.5	
California Power Holdings C-3775-15-9	4157	3100	30	0.355	2013	**0.59**	0.0070
					2015	0.3	
					2017	0.5	
California Power Holdings C-3775-16-9	4157	3,100	30	0.355	2013	0.82	0.0106
					2015	**0.9**	
					2017	0.5	
Modesto Irrigation District N-3233-6-3	11667	8,440	20	0.219	2016	**2.1**	0.0230
					2017	1.8	
					2018	1.3	
Modesto Irrigation District N-3233-7-3	11667	8,440	20	0.219	2016	**2.4**	0.0263
					2017	2	
					2018	1.3	
Modesto Irrigation District N-3233-8-3	11667	8,440	20	0.219	2016	**2.1**	0.0230
					2017	1.9	
					2018	1.2	
Modesto Irrigation District N-3233-9-3	11667	8,440	20	0.219	2016	1	0.0306
					2017	**2.8**	
					2018	1.3	
Modesto Irrigation District N-3233-10-3	11667	8,440	20	0.219	2016	0.011	0.0646
					2017	2.4	
					2018	**5.9**	
Modesto Irrigation District N-3233-11-3	11667	8,440	20	0.219	2016	3	0.0339
					2017	**3.1**	
					2018	2.8	

Based on an extensive review of California air district rules and BACT guidelines, and a survey of source tests for IC engines permitted in the District, the following VOC control options were identified:

<u>VOC Control Option #1</u>

- For all Compression-Ignited Engines: Use of an engine meeting the latest Tier standard;
- For all spark-ignited engines: 25 ppmvd VOC @ 15% O_2 or 0.15 g/bhp-hr

This option is based upon the District's previous achieved-in-practice BACT Guideline requirements and has been achieved by multiple units within the District.

VOC Control Option #2

- For Compression-Ignited Engines: 50 percent reduction of latest Tier standard for VOC emissions using a catalytic oxidation system;
- For rich burn spark-ignited engines: 12 ppmvd @ 15% O2 or 0.069 g/bhp-hr

This option is based on the District's previous technologically feasible BACT Guideline requirements for full time compression ignited IC engines. No full-time compression ignited IC engines were identified in the District's survey of permitted units. The rich-burn engines within the District are complying with the VOC limit listed in this option of 12 ppmvd @ 15% O2 or 0.069 g/bhp-hr.

VOC Control Option #3 - 0.10 lb-VOC/MW-hr

This option is based on SCAQMD Rule 1110.2 and the SCAQMD BACT requirements for IC engines installed after February 1, 2008 that are used for non-emergency electrical generation.

South Coast AQMD Rule 1110.2 allows operators of IC engines used to generate both heat and electric power to demonstrate compliance with the VOC emissions standard of 0.10 lb/MW-hr by taking credit for the recovered thermal energy at the of one MW-hr for each 3.4 million Btus of heat recovered.

Nearly all of the units operating within the District have source tested at levels that achieve the 0.10 lb-VOC/MW-hr limit of South Coast AQMD Rule 1110.2. Furthermore, South Coast AQMD provided the following list of engines powering electrical generators that are currently complying with Rule 1110.2 requirements.

Facility	Engine/Control Equipment	bhp	VOC Emission Limit
Palm Springs City (Facility ID 42218)	Lean-Burn GE Jenbachher Model #JMS416B86 Engine with SCR	1,573	0.17 lb/MW_e-hr*
Play Capital Company (Facility ID 176353)	Rich Burn GE/Tecogen Model 7400 Engine with a 3-way catalyst	108	0.444 lb/MW_e-hr*
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #1: Rich-Burn Generac Model 6.8GNGD-100 Engine with a 3-way catalyst	147	0.20 lb/MW-hr
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #2: Rich-Burn Generac Model 6.8GNGD-100 Engine with a 3-way catalyst	147	0.20 lb/MW-hr
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #3: Rich-Burn Generac Model 6.8GNGD-130 Engine with a 3-way catalyst	189	0.20 lb/MW-hr
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #4: Rich-Burn Generac Model 6.8GNGD-130 Engine with a 3-way catalyst	189	0.20 lb/MW-hr
Southern California Gas Company – Aliso Canyon (Facility ID 800128)	Engine #5: Rich-Burn Generac Model 13.3 GTA-250 Engine with a 3-way catalyst	385	0.20 lb/MW-hr

Facility	Engine/Control Equipment	bhp	VOC Emission Limit
Coachillin' Holdings (Facility ID 187790)	Engine #1: Lean-Burn Mechanishe Werstatte Mannheim Model TCG-2016-V16 Engine with SCR and Oxidation Catalyst	1,107	0.43 lb/MW$_e$-hr*
Coachillin' Holdings (Facility ID 187790)	Engine #2: Lean-Burn Mechanishe Werstatte Mannheim Model TCG-2016-V16 Engine with SCR and Oxidation Catalyst	1,107	0.43 lb/MW$_e$-hr*

* This engine is complying with the overall SCAQMD Rule 1110.2 Rule limit of 0.10 lb-VOC/MW-hr by using a thermal credit as specified in the Rule. SCAQMD used the quantity of heat recovered for this cogeneration system to calculate a lb-VOC/MW$_e$-hr emission limit that is equivalent to the 0.VOC lb-CO/MW-hr Rule limit.

Based on data from permitted engines operating within SJVAPCD, the 0.10 lb-VOC/MW-hr limit is approximately equivalent to:

- 17 ppmvd VOC @ 15% O_2 (as CH_4) for units with heat recovery
- 10 ppmvd VOC @ 15% O_2 (as CH_4) for units without heat recovery

For the proposed 1,966 bhp IC engine powering a 1,429 kW electrical generator, 0.010 lb-VOC/MW-hr is calculated to be equivalent to the following:

bhp Rating: 1,966 bhp
Electrical Production: 1,429 kW$_e$ ÷ 1,000 kW$_e$/MW$_e$ = 1.429 MW$_e$
Heat Recovery: 5.4 MMBtu/hr ÷ (3.4 MMBtu/hr)/MW$_{th}$ = 1.588 MW$_{th}$
Engine Efficiency: 36%

(1.429 MW$_e$ + 1.588 MW$_{th}$) x 0.010 lb-VOC/MW-hr = 0.3017 lb-VOC/hr

0.3017 lb-VOC/hr x 453.59 g/lb ÷ 1,966 bhp = 0.07 g-VOC/bhp-hr

<u>VOC – 0.07 g/bhp-hr</u>

$$0.07\ \frac{\text{g VOC}}{\text{bhp}-\text{hr}} \times \frac{1\ \text{lb}}{453.59\ \text{g}} \times \frac{1\ \text{bhp}-\text{hr}}{2{,}545\ \text{Btu}} \times \frac{0.36\ \text{Btu}_{\text{out}}}{1\ \text{Btu}_{\text{in}}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} = 0.0218\ \frac{\text{lb VOC}}{\text{MMBtu}}$$

$$0.0218\ \frac{\text{lb VOC}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ \text{O}_2}{20.9\%\ \text{O}_2} \times \frac{1\ \text{MMBtu}}{8{,}578\ \text{ft}^3} \times \frac{379.5\ \text{ft}^3}{\text{lb}-\text{mole}} \times \frac{\text{lb}-\text{mole}}{16\ \text{lb VOC}} \times \frac{10^6\ \text{ppmv}}{1} = 17\ \text{ppmv VOC @ 15\% O}_2$$

<u>VOC Control Option #4: Electric Motor (except for engines that will be used to generate electricity)</u>

This option is was listed as Alternate Basic Equipment basic equipment in the District's previous BACT Guideline 3.3.12, but is not applicable for engines used to generate electricity.

VOC Control Option #5: Fuel Cell (≤ 0.02 lb-VOC/MW-hr)

This option is listed as Alternate Basic Equipment basic equipment in the District's BACT Guideline 3.3.15 for digester gas-fired IC engines and through a technology transfer, will be considered for the engine when fired on natural gas.

b. Step 2 - Eliminate technologically infeasible options

VOC Control Option #1, Part 1 (For Compression-Ignited Engines):

The first part of Control Option #1 - Use of an engine meeting the latest Tier standard for all compression ignited engines is not applicable for the proposed engine because it is a spark-ignited engine; therefore, this option will be removed from consideration for this BACT analysis.

VOC Control Option #2 (For Compression-Ignited Engines and Spark-Ignited Rich-Burn IC Engines):

Control Option #2 – 50% reduction of latest Tier standard for VOC emissions using a catalytic oxidation system for compression ignited engines and a VOC limit of 12 ppmvd @ 15% O_2 or 0.069 g/bhp-hr for rich-burn spark ignited engines is not applicable for the proposed engine because it is a spark-ignited lean-burn IC engine; therefore, this option will also be removed from consideration for this BACT analysis.

VOC Control Option #4: Electric Motor (except for engines that will be used to generate electricity) (Alternate Basic Equipment)

Option 2, Electric Motor, is not feasible for the project since the proposed engine will be used to generate electric power; therefore, this option will be eliminated from consideration.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb-VOC/MW-hr)

2) 0.010 lb-VOC/MW-hr* (approximately 10 ppmvd VOC @ 15% O_2 for units without heat recovery and 17 ppmv VOC @ 15% O_2 for units with heat recovery) (based on SCAQMD Rule 1110.2 - Achieved in Practice)

   *When determining compliance with the lb/MW-hr VOC requirement, engines with heat recovery may include up to one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr) in addition to each MW-hr of net electricity produced ($MW_{e\text{-}hr}$)

d. Step 4 - Cost Effectiveness Analysis

<u>Option 1: Fuel Cell (≤ 0.10 lb-CO/MW-hr) (Alternate Basic Equipment)</u>

The multi-pollutant cost analysis performed above for the NO_X, CO, and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X, CO, and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

<u>Option 2: VOC emissions ≤ 0.010 lb-VOC/MW-hr (Achieved in Practice)</u>

This option is achieved in practice and the applicant has proposed an IC engine with VOC emissions ≤ 0.07 g-VOC/bhp-hr (equivalent to 0.010 lb-VOC/MW-hr with credit for heat recovery) when it is fueled with natural gas, which is equivalent to this Achieved in Practice BACT requirement; therefore, a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engine when fueled with natural gas is VOC emissions ≤ 0.07 g-VOC/bhp-hr (equivalent to 0.010 lb-VOC/MW-hr with credit for heat recovery). The applicant has proposed IC engine with VOC emissions < 0.07 g-VOC/bhp-hr. Therefore, the BACT requirements for VOC will be satisfied.

APPENDIX G

BACT Analysis for IC Engine when Fueled with Digester Gas

SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*
Last Update: 3/6/2013

Waste Gas-Fired IC Engine**

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO_X	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)		1. Fuel Cells (<0.05 lb/MW-hr) 2. Microturbines (<9 ppmv @ 15% O_2) 3. Gas Turbine (<9 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
SO_X	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S) (dry absorption, wet absorption, chemical H_2S reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance)		
PM_{10}	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)		
CO	2.0 g/bhp-hr		1. Fuel Cells (<0.10 lb/MW-hr) 2. Microturbines (<60 ppmv @ 15% O_2) 3. Gas Turbine (<60 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
VOC	0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent)		Fuel Cells (<0.02 lb-VOC/MW-hr as CH_4)
Ammonia (NH_3) Slip***	≤ 10 ppmv @ 15% O_2		

*** For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

**** District BACT Guideline 3.3.15 is being amended to remove NH_3 slip emission requirements since NH_3 slip results from operation of an emissions control device (SCR) and, therefore, does not trigger BACT.*

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

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

Top-Down BACT Analysis for Digester Gas-Fired IC Engine

Current District BACT Guideline 3.3.15 applies to the proposed natural gas/digester gas-fired IC engine when it is fueled with digester gas. In accordance with the District BACT policy, information from District BACT Guideline 3.3.15 will be utilized for the BACT analysis for the digester gas-fired engine proposed under this project.

I. Proposal

E & J Gallo Winery has requested an Authority to Construct (ATC) permit for the installation of a new 1,966 bhp lean-burn IC engine with a selective catalytic reduction (SCR) system to control emissions that will power a 1,429 kW electrical generator and will be fueled with natural gas and digester gas from the existing wastewater anaerobic reactor (ATC N-1237-892-0). The applicant has proposed to limit operation of the new IC engine to 8,400 hours per year.

II. BACT Applicability

New emissions units – PE > 2.0 lb/day

BACT Applicability for New Emissions Unit for N-1237-892-0 When Fueled with Digester Gas				
Pollutant	PE2 for each unit after commissioning (lb/day)	BACT Threshold (lb/day)	SSPE2 (lb/yr)	BACT Triggered?
NO_X (Normal Operation)	5.2	> 2.0	N/A	**Yes***
SO_X	3.1	> 2.0	N/A	**Yes**
PM_{10}	5.2	> 2.0	N/A	**Yes**
CO	14.6	> 2.0 and SSPE2 ≥ 200,000 lb/yr*	650,811	**Yes**
VOC	5.2	> 2.0	N/A	**Yes***
NH_3	4.7	> 2.0	N/A	No***

* BACT for NO_X and VOC also triggered for Federal Major Modifications for these pollutants

** BACT is not required for CO from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

*** NH_3 results from operation of an emissions control device (SCR) and, therefore, NH_3 emissions do not trigger BACT. However, NH_3 slip emissions from the proposed unit will still be limited by the permit to no more than 10 ppmv @ 15% O_2.

III. Top-Down BACT Analyses for the Natural Gas/Digester Gas-Fired Engine when Fueled with Digester Gas

As stated above, the information form the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engines will be utilized for the BACT analysis for the proposed natural gas/digester gas-fired IC engine evaluated under this project when it is fueled with digester gas.

1. BACT Analysis for NO_X Emissions:

a. Step 1 - List all control technologies

District BACT Guideline 3.3.15 lists the following options to reduce NO_X emissions from digester gas-fired IC engines:

1) NO_X emissions ≤ 0.15 g-NO_X/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

2) Fuel Cell (≤ 0.05 lb-NO_X/MW-hr) (Alternate Basic Equipment)

3) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

4) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

<u>Description of Control Technologies</u>

1) NO_X emissions ≤ 0.15 g-NO_X/bhp-hr (9-11 ppmv NO_X @ 15% O_2) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)

A Selective Catalytic Reduction (SCR) system operates as an external control device where exhaust gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen (N_2), water vapor, and other by-products. The use of an SCR system typically reduces NO_X emissions by 90% or more.

2) Fuel Cell (≤ 0.05 lb- NO_X/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these fuel cells, which operate at high temperatures, are tolerant of CO_2 that is found biogas.

Fuel cells offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells has been the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense, the cost of periodic replacement of the fuel cell stack, and, for biogas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, biogas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas, such as landfill gas and brewery wastewater gas.

3) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest ways of generating electricity through combustion. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, NO_X emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for biogas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, biogas-fired turbines used to produce electricity are expected to be available in the size range of 2.5 - 7 MW. According to Solar Turbines, the smaller biogas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

4) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gas. According to the California Air Resources Board (ARB), there were approximately 200 biogas-fired microturbines operating in California as of the year 2006.[12] Microturbines typically have electrical efficiencies of 25-30% based on the lower heating value (LHV) of the fuel, with larger microturbines usually having greater efficiencies than smaller microturbines. Microturbine manufacturers include Capstone Green Energy and FlexEnergy Solutions.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_X, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_X (DLN)) combustion technology. Microturbine manufacturers will generally guarantee NO_X emissions of 9-15 ppmv @ 15% O_2 for microturbines fuel with biogas. However, several emission tests performed on biogas-fired microturbines have demonstrated lower emissions.

The proposed project is for a 1,429 kW natural gas and digester gas-fueled IC engine that will be used to produce combined heat and power for the operations at an existing winery and, although larger microturbines have recently become available, at least two microturbines packages with several individual microturbines would be required to replace the proposed IC engine. In addition, for previous projects that the District evaluated for the installation of digester gas-fired IC engines for power production, the applicants indicated that when they investigated microturbines as an alternative they found that there were difficulties related to the loss of power and efficiency because of heat de-rating in warmer climates and the very high pressure requirement and parasitic load, which increased overall costs. Although microturbines may not currently be a practical option for this particular project, they will be included as alternative equipment in the BACT analysis below.

b. Step 2 - Eliminate technologically infeasible options

<u>Option 3 - Gas Turbine (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)</u>

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (e.g. Solar Turbines, Allison, and General Electric) do not currently produce or market gas turbines fueled with digester gas rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[13] (September 2017) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][14] (October 5, 2015) also supports that gas turbines rated less than approximately 3 MW are not generally available. The smallest

[12] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)
[13] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (September 2017) http://www.epa.gov/chp/catalog-chp-technologies
[14] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015). https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/2/7889-20151119finalfullreport-1-.pdf

turbine for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

The proposed project would require a gas turbine rated approximately 1,429 kWe, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration. However, the NO_X emission limit that the applicant has proposed for the engine, 0.051 g-NOx/bhp-hr (equivalent to 4.1 ppmvd NOx @ 15% O_2), is expected to be no greater than the NO_X emission limit that would be achieved by a comparably sized gas turbine.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.05 lb-NO_X/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

2) Digester gas-fueled microturbines (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

3) NO_X emissions ≤ 0.15 g-NO_X/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

As explained above, because the application for this project was deemed complete after the June 1, 2021 updates to the District BACT Policy, the BACT analysis for this project will utilize the new District BACT policy and cost-effectiveness thresholds that was in effect at the time that the application was deemed complete.

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy (dated June 1, 2021), a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. To determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District rules that are applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The lean burn, natural gas/digester gas-fired IC engine is currently subject to the following emission limits for non-agricultural, lean burn IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2e: 11 ppmvd NO_X, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2). The proposed natural gas/digester gas-fired IC engine is also subject to the New Source Performance Standards (NSPS) for spark-ignited IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes more stringent CO and VOC emissions limits of 5.0 g-CO/bhp-hr (or 610 ppmv CO @ 15% O_2) and 1.0 g-VOC/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane) for landfill and digester gas-fired IC engines.

Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engine will be based on the emission limits contained in these applicable regulations.

Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Because fuel cells result in reduced NO_X, CO, and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis demonstrates that replacement of the proposed engine with a fuel cell is not cost effective even when the additional operation costs of a fuel cell are not considered.

Assumptions

- F Factor for the Digester Gas ≈ 9,030 dscf/MMBtu (dry, adjusted to 60 °F) (based on the August 25, 2020 analysis of the digester gas composition)
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,412.14 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engine and fuel cells will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[13] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][14]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]
- Price for electricity: $127.72/MW-hr (based on the current California Bioenergy Market Adjusting Tariff (BioMAT) contract price offered by Investor Owned for electricity produced from Category 1 - biogas from wastewater treatment, municipal organic waste diversion, food processing, and co-digestion[15])

[15] See the California Public Utilities Commission (CPUC) Bioenergy Feed-Tariff (SB 1122) webpage at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-procurement-programs/rps-sb-1122-biomat; Pacific Gas & Electric Company (PG&E) BioMAT Feed-in Tariff contract price pricing at https://www.pge.com/en_US/for-our-business-partners/floating-pages/biomat/biomat.page?WT.mc_id=Vanity_rfo-biomat&ctx=large-business, and the California Public Utilities Commission (CPUC) 2020 California Renewables Portfolio Annual Report (November 2020). https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/2020-rps-annual-report.pdf

<u>Assumptions for the Proposed Natural Gas/Digester Gas-Fired IC Engine (ATC N-1237-892-0) when fueled with Digester Gas</u>

- The IC engine will operate at up to full load for 24 hour/day and 8,400 hour/year (applicant's proposal)

- Higher Heating Value (hhv) efficiency for the IC engine: 35% (assumed based on information from the engine supplier)

- The maximum daily total heating value of the digester gas used to fuel the engine will be: 343.1 MMBtu/day (*1,966 bhp_{out} x 1 bhp_{in}/0.35 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 24 hr/day*)

- The maximum annual total heating value for of the digester gas used by the engine will be: 120,083.3 MMBtu/year (*1,966 bhp_{out} x 1 bhp_{in}/0.35 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 8,400 hr/year*)

- Estimated purchase and installation cost for CHP IC engine producing approximately 1,429 kWe without add-on air pollution control equipment: $1,891/kW (*Average of interpolated costs from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 based on US Consumer Price Index (CPI) Inflation Calculator*)

- Additional capital investment for biogas conditioning and cleanup for IC engines: $452/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 based on US CPI Inflation Calculator*)

- Total Installation Cost for biogas-fueled IC engine that can produce 1,429 kWe: $2,343/kW

- Estimated operation costs for CHP IC engine that can produce 1,429 kWe without add-on air pollution control costs: $0.022/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 based on US CPI Inflation Calculator*)

- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engine must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT. Because required level of sulfur removal is adequate for use in the engine, there will be no increase in operating costs related to cleaning the digester gas for use in the IC engine

- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 11 ppmv @ 15% O_2 = 0.0427 lb/MMBtu

- Rule 4702 CO emission limit for non-agricultural, lean burn IC engines: 2,000 ppmv @ 15% O_2 as CH_4 = 4.72 lb/MMBtu

- 40 CFR 60 Subpart JJJJ CO emission limit for landfill and digester gas-fired IC engines: 5.0 g/bhp-hr (or 610 ppmv @ 15% O_2)

- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% O_2 as CH_4 = 1.012 lb/MMBtu

- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane)

Assumptions for Fuel Cell System

- Net electrical hhv efficiency for a fuel cell: 49% (2016-2017 Self Generation Incentive Program Impact Evaluation[16] (September 28, 2018) submitted to the Pacific Gas and Electric Company SGIP Working Group reports lower heating value (LHV) efficiencies for Fuel Cells used only for electrical generation of 54% in 2016 and 55% in 2017. This results in an average LHV efficiency of 54.5% for 2016-2017 and an estimated average higher heating value (HHV) efficiency of 49% for 2014-2015)

- Size of fuel cell system needed to replace the proposed 1,429 kWe IC engine: 2,100 kW (estimated based on 343.1 MMBtu/day and 49% efficiency)

- Estimated Purchase and Installation Cost for a 2,100 kW Molten Carbonate Fuel Cell: $5,266/kW (*Average of values for largest fuel cells from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 dollars based on CPI Inflation Calculator; Note: the U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 10-21-2016 and available at: http://www.wbdg.org/resources/fuelcell.php) states, "Installation costs of a fuel cell system can range from $5,000/kW to $10,000/kW." Therefore, this estimate falls within the expected range and is below recently reported costs for some fuel cells.*)

- Additional capital investment for biogas conditioning and cleanup for fuel cells: $658/kW (*inflation adjusted value from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)

[16] Self Generation Incentive Program Impact Evaluation (September 28, 2018) Prepared by Itron, submitted to the Pacific Gas and Electric Company SGIP Working Group, Section 4 – Generation Project Energy Impacts, Figure 4-34 - 2017 Overall and Component LHV Efficiencies by Technology. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program/self-generation-incentive-program-evaluation-reports

- Total Installation Cost for biogas-fueled fuel cells rated 2,100 kW: \$5,924/kW

- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: \$0.047/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 dollars based on CPI inflation calculator*)

- Additional operational costs for biogas conditioning and cleanup for 2,100 kW fuel cell: \$0.175/kW-hr (*Interpolated value SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] adjusted to 2021 dollars based on CPI inflation calculator*)

- Total Operation Cost for biogas-fueled fuel cells rated 2,100 kW: \$0.22/kW-hr

- Fuel Cell NO_X emissions: 0.01 - 0.02 lb/MW-hr *(Note: Fuel cells have been certified to the ARB Distributed Generation Certification level of 0.07 lb-NO_X/MW-hr but measured emissions from fuel cells are generally much lower)*

- Fuel Cell CO emissions: 0.10 lb-CO/MW-hr (Based on ARB Distributed Generation Certification level and emission tests on fuel cells)

- Fuel Cell VOC emissions: 0.02 lb-VOC/MW-hr (≤ 2.0 ppmv VOC @ 15% O_2 as CH_4 based on ARB Distributed Generation Certification level and emission tests on fuel cells)

<u>Capital Cost</u>

The estimated increased incremental capital cost for replacement of the proposed IC engine with fuel cells is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engine.

The incremental capital cost for replacement of the proposed IC engine with a fuel cell power plant is calculated as follows:

(2,100 kW x \$5,924/kW) - (1,429 kW x \$2,343/kW) = \$9,092,253

<u>Annualized Capital Cost</u>

Pursuant to District Policy APR 1305, Section X (dated June 1, 2021), which was in effect at the time that the application for this project was deemed complete, the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 4% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

A = $[P \times i(I+1)^n]/[(I+1)^n-1]$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (4%)
N = Equipment Life (10 years)

A = $[\$9,092,253 \times 0.04(1.04)^{10}]/[(1.04)^{10}-1]$
= **$1,118,347/year**

Annual Costs

Electricity Generated
The amount of electricity potentially generated by each option is calculated as follows:

Proposed IC Engine Producing 1,429 kWe
1,429 kWe x 8,400 hr/yr = 12,003,600 kW-hr/year

Fuel Cells (Alternate Equipment)
343.1 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,412.14 Btu x 0.49 (electrical efficiency) = 2,053 kWe

120,083.3 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,412.14 Btu x 0.49 (electrical efficiency) = 17,244,549 kW-hr/year

Cost (Decrease) from Increased Revenue for Power Generation from Replacing the Proposed 1,429 kW Engine with a Fuel Cell System
(12,003,600 kW-hr/yr - 17,244,549 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = -$669,374/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Proposed IC Engine Producing 1,429 kWe
12,003,600 kW-hr/yr x $0.022/kW-hr = $264,079/year

Fuel Cells (Alternate Equipment)
17,244,549 kW-hr/yr x $0.22/kW-hr = $3,793,801/year

Annual Costs of Increased Maintenance
$3,793,801/yr - $264,079/yr = $3,529,722/year

Total Increased Annual Costs for Fuel Cell as an Alternative to Proposed IC Engine
$1,118,347/year + (-$669,374/year) + $3,529,722/year = **$3,978,695/year**

Emission Reductions:

NOx, CO, and VOC Emission Factors:

Pursuant to the District's Policy APR 1305 (dated June 1, 2021), which was in effect at the time that he application for this project was deemed complete, District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the IC engine will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.2, Table 2, 2.e. The District Standard Emissions for CO and VOC emissions from the engines will be based on the New Source Performance Standard (NSPS) CO and VOC emission limits for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since these limits are applicable and are more representative of the emissions than the current applicable CO and VOC emission limits of District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions:
NO_X: 0.0427 lb-NO_X/MMBtu (11 ppmv NO_X @ 15% O_2)
CO: 5.0 g-CO/bhp-hr
VOC: 1.0 g-VOC/bhp-hr

Emissions from Fuel Cells as Alternative Equipment:
NO_X: 0.01 lb-NO_X/MW-hr
CO: 0.10 lb-NO_X/MW-hr
VOC: 0.02 lb-VOC/MW-hr

Emission Reductions:

Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO_X Emission Reductions (11 ppmv NO_X @ 15% O_2 → 0.01 lb-NO_X/MW-hr)
(120,083.3 MMBtu/yr x 0.0427 lb-NO_X/MMBtu) – (17,244,549 kW-hr/yr x 1 MW/1,000 kW x 0.01 lb-NO_X/MW-hr)
= 4,955 lb-NO_X/year (2.478 ton-NO_X/year)

CO Emission Reductions (5.0 g-CO/bhp-hr → 0.10 lb-CO/MW-hr)
(1,966 bhp x 8,400 hr/yr x 5.0 g-CO/bhp-hr x 1 lb/453.59 g) – (17,244,549 kW-hr/yr x 1 MW/1,000 kW x 0.10 lb-CO/MW-hr)
= 180,317 lb-CO/year (90.158 ton-CO/year)

VOC Emission Reductions (1.0 g-VOC/bhp-hr → 0.02 lb-VOC/MW-hr)
(1,966 bhp x 8,400 hr/yr x 1.0 g-VOC/bhp-hr x 1 lb/453.59 g) – (17,244,549 kW-hr/yr x 1 MW/1,000 kW x 0.02 lb-VOC/MW-hr)
= 36,063 lb-VOC/year (18.032 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Threshold (MCET) for NO_X, CO, and VOC Reductions based on District Standard Emission Reductions

Multi-Pollutant Cost Effectiveness Threshold (MCET) for the NO_X, CO, and VOC reductions from replacing the proposed IC engine with fuel cells is calculated below using the cost effectiveness thresholds from the District's Revised BACT Cost Effectiveness Thresholds Memo, dated May 14, 2008.

(2.478 ton-NO_X/year x \$31,600/ton-NO_X) + (90.158 ton-CO/year x \$400/ton-CO) + (18.032 ton-VOC/year x \$22,600/ton-VOC)
= **\$521,891/year**

As shown above, the annualized capital cost of this alternate option exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO_X and VOC emission reductions. Therefore, this option is not cost effective and is being removed from consideration.

Option 2 - Microturbines (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

The applicant has proposed an IC engine with NO_X emissions of 0.051 g-NOx/bhp-hr (equivalent to 4.1 ppmvd NOx @ 15% O_2) when it is fueled with digester gas. The NO_X emissions from the proposed IC engine when fueled with digester gas are less than or equal to the NO_X emissions achieved by this alternative; therefore, this option does not need to be considered further and a cost analysis is not required.

Option 3: NO_X emissions ≤ 0.15 g-NO_X/bhp-hr (Achieved in Practice)

This option is achieved in practice and the applicant has proposed an IC engine with NO_X emissions of 0.051 g-NOx/bhp-hr when it is fueled with digester gas, which is lower than this Achieved in Practice BACT requirement; therefore, a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the proposed natural gas/digester gas-fired IC engine when it is fueled with digester gas satisfied with the following: NO_X emissions to ≤ 0.051 g-NOx/bhp-hr, as proposed by the applicant. The applicant has proposed to use an SCR system for the natural gas/digester gas-fired lean burn IC engine to reduce NO_X emissions to ≤ 0.051 g-NOx/bhp-hr. Therefore, the BACT requirements for NO_X will be satisfied.

2. BACT Analysis for SO_X Emissions:

a. Step 1 - Identify all control technologies

The following control was identified to reduce SO_X emissions from combustion of the digester gas as fuel in the proposed IC engine:

Sulfur Content of fuel ≤ 40 ppmv as H_2S (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

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

c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for SO_X emissions from the proposed IC engine when fueled with digester gas is sulfur content of the digester gas not exceeding 40 ppmv as H_2S. The applicant has proposed to reduce the sulfur content of the digester gas combusted in the IC engine to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_X will be satisfied.

3. BACT Analysis for PM_{10} Emissions:

a. Step 1 - Identify all control technologies

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter (PM). Natural Gas and digester gas from winery wastewater are the proposed fuel for the proposed IC engine. The digester gas will be composed primarily of methane (approximately 60-70% molar composition) and CO_2 (approximately 30-40% molar composition) and is expected to burn in a fairly clean manner, similar to natural gas. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly H_2S) resulting in the formation of sulfur-containing particulate. Therefore, reducing the sulfur content of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce emissions of particulate matter from combustion of the digester gas as fuel in the proposed IC engine:

Sulfur Content of fuel ≤ 40 ppmv as H_2S (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

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

c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for PM_{10} emissions from the proposed IC engine when fueled with digester gas is sulfur content of the digester gas not exceeding 40 ppmv as H_2S. The applicant has proposed to reduce the sulfur content of the digester gas combusted in the IC engine to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for PM_{10} will be satisfied.

4. BACT Analysis for CO Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce CO emissions:

1) CO emissions ≤ 2.0 g-CO/bhp-hr (Achieved in Practice)

2) Fuel Cell (≤ 0.10 lb-CO/MW-hr) (Alternate Basic Equipment)

3) Microturbines (<60 ppmv CO @ 15% O_2) (Alternate Basic Equipment)

4) Gas Turbine for projects ≥ 3 MW (<60 ppmv CO @ 15% O_2) (Alternate Basic Equipment)

b. Step 2 - Eliminate technologically infeasible options

Option 4 - Gas Turbine (≤ 60 ppmv CO @ 15% O_2) (Alternate Basic Equipment)

As discussed above, Option 4, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines do not currently produce or market gas turbines fueled with digester gas rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The proposed project would require a gas turbine rated approximately 1,429 kWe, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time. However, the CO emission limit that the applicant has proposed for the engine, 0.14 g-CO/bhp-hr (equivalent to 19.5 ppmvd CO @ 15% O_2), is expected to be no greater than the CO emission limit that would be achieved by a comparably sized gas turbine.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.10 lb-CO/MW-hr) (Alternate Basic Equipment)

2) Microturbines (<60 ppmv CO @ 15% O_2) (Alternate Basic Equipment)

3) CO emissions ≤ 2.0 g-CO/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.10 lb-CO/MW-hr) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the NO_X, CO, and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X, CO, and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2 - Microturbines (<60 ppmv CO @ 15% O_2) (Alternate Basic Equipment)

The applicant has proposed an IC engine with CO emissions of 0.14 g-CO/bhp-hr (equivalent to 19.5 ppmvd CO @ 15% O_2) when it is fueled with digester gas. The CO emissions from the proposed IC engine when fueled with digester gas are less than or equal to the CO emissions achieved by this alternative; therefore, this option does not need to be considered further and a cost analysis is not required.

Option 3: CO emissions ≤ 2.0 g-CO/bhp-hr (Achieved in Practice)

This option is achieved in practice and the applicant has proposed an IC engine with CO emissions ≤ 0.14 g-CO/bhp-hr when it is fueled with digester gas, which is lower than this Achieved in Practice BACT requirement; therefore, a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the proposed natural gas/digester gas-fired IC engine when it is fueled with digester gas satisfied with the following: CO emissions to ≤ 0.14 g-CO/bhp-hr, as proposed by the applicant. Because the applicant has proposed this option, the BACT requirements for CO will be satisfied.

5. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) VOC emissions ≤ 0.10 g-VOC/bhp-hr (Achieved in Practice)

2) Fuel Cell (≤ 0.02 lb-VOC/MW-hr) (Alternate Basic Equipment)

b. Step 2 - Eliminate technologically infeasible options

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

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb-VOC/MW-hr) (Alternate Basic Equipment)

2) VOC emissions ≤ 0.10 g-VOC/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as CH_4) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the NO_X, CO, and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X, CO, and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g-VOC/bhp-hr (Achieved in Practice)

This option is achieved in practice and the applicant has proposed an IC engine with VOC emissions ≤ 0.052 g-VOC/bhp-hr when it is fueled with digester gas, which is lower than this Achieved in Practice BACT requirement; therefore, a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the proposed natural gas/digester gas-fired IC engine when it is fueled with digester gas satisfied with the following: VOC emissions to ≤ 0.052 g-VOC/bhp-hr, as proposed by the applicant. Because the applicant has proposed this option, the BACT requirements for VOC will be satisfied.

APPENDIX H

ERC Surplus Analyses

San Joaquin Valley Air Pollution Control District
Surplus ERC Analysis

Facility Name:	E & J Gallo Winery	**Date:**	March 10, 2022
Mailing Address:	5610 E Olive Ave Fresno, CA 93727	**Engineer:**	Jesse A. Garcia
		Lead Engineer:	Derek Fukuda
Contact Person:	Kim Burns		
Telephone:	(559) 458-2457		
ERC Certificate #:	N-1568-2		
ATC Project #:	N-1211986		

I. Proposal

The District previously performed an analysis of the current surplus value of Emission Reduction Credit (ERC) certificate N-1483-2, which was owned by Ingredion Incorporated at the request of E & J Gallo Winery with authorization from Ingredion Incorporated. E & J Gallo Winery subsequently purchased a portion of the ERCs represented by ERC certificate N-1483-2, with resulting ERC certificate N-1568-2 issued to E & J Gallo Winery and the remaining ERCs re-issued to Ingredion Incorporated as ERC certificate N-1569-2 under District Project N-1212682. This analysis will update the previous surplus analysis performed for ERC certificate N-1483-2 to reflect current ERC certificate N-1568-2.

Proposed ERC Certificate(s)	
Certificate #	**Criteria Pollutant**
N-1568-2	NOx

The purpose of this analysis is to ensure that the emission reductions on this ERC certificate are surplus of all applicable Federal requirements; therefore, this analysis establishes the surplus value of the ERC certificate as of the date of this analysis. The current face value and surplus value of the ERC certificate evaluated in this analysis are summarized in the following table:

Criteria Pollutant Summary: NOx

ERC Certificate N-1568-2				
Pollutant	1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
Current Value	5,000	5,000	5,000	5,000
Surplus Value	5,000	5,000	5,000	5,000

II. Individual ERC Certificate Analysis

ERC Certificate N-1568-2

A. ERC Background

Criteria Pollutant: NOx

ERC Certificate N-1568-2 is a certificate that was split out from parent ERC Certificate N-1086-2. Original ERC Certificate N-1086-2 was issued to N-802 on January 6, 2014 under project N-1122754. The ERCs were generated from the shutdown of emission units at a solid fuel-fired power plant, facility ID N-802, which included a 620 MMBtu/hr coal-fired circulating fluidized bed boiler and various auxiliary equipment (see detailed equipment summary in Attachment 1). Of the units shut down, the boiler under permit N-802-1 was the only source of NOx emissions, therefore, the other permits will not be evaluated as part of this analysis. The following table summarizes the values of the original parent certificate and the current value of the subject certificate:

ERC Certificate N-1568-2				
Pollutant	1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
Original Value of Parent Certificate N-1086-2	38,860	26,235	34,589	37,804
Current Value of ERC Certificate N-1568-2	5,000	5,000	5,000	5,000

B. Applicable Rules and Regulations at Time of Original Banking Project

Based on the application review for the original ERC banking project, the following rules and regulations were evaluated to determine the surplus value of actual emission reductions of NOx generated by the reduction project.

1. District Rules

Rule 2301 - Emission Reduction Credit Banking (1/19/12)

The application review for the original ERC banking project demonstrated that the ERC credit complied with District Rule 2301 requirements at the time it was issued.

Rule 4352 Solid Fuel Fired Boilers, Steam Generators and Process Heaters (12/15/11)

The application review for the original ERC banking project demonstrated that the emission reductions were surplus of all Rule 4352 limits. The rule has not been modified since the banking project was finalized. There are therefore no new or additional requirements that could affect the surplus value of the original reductions.

2. Federal Rules and Regulations

40 CFR Part 60 Subpart Da - Standards of Performance for Electric Utility Steam Generating Units

The application review for the original ERC banking project demonstrated that the boiler had a NO_X limit that was below the limit in the subpart. Therefore, the emission reductions were surplus of the requirements of any applicable federal rules or regulations at the time the ERC was originally banked.

C. New or Modified Rule and Regulations Applicable to the Original Banking Project

All District and federal rules and regulations that have been adopted or amended since the date the original banking project was finalized will be evaluated below:

1. District Rules:

There are no new or modified District rules that would apply to the boiler that was shut down in the original ERC banking project. Therefore, the original NOx emission reductions continue to be surplus of District rule requirements.

2. Federal Rules and Regulations:

40 CFR Part 60 Subpart Da - Standards of Performance for Electric Utility Steam Generating Units

Various sections of this federal regulation have been updated since the original ERC banking project was finalized in January of 2014. The following sections of this subpart were updated: 60.41Da – *Definitions*; 60.42Da – *Standards for Particulate Matter (PM)*; 60.48Da – *Compliance Provisions*; 60.49Da – *Emissions Monitoring*; and 60.50Da – *Compliance Determination Methods and Procedures*. The updates to these sections of the subpart do not result in any changes to the NOx emissions limits allowed by this subpart. Therefore, the original NOx emission reductions continue to be surplus of federal rules and regulations.

D. Surplus at Time of Use Adjustments to ERC Quantities

As demonstrated in the section above, the emissions reductions from permit units in the original banking project continue to be surplus of all applicable District and Federal Rules and Regulations. Therefore, no discounting to the ERC values are necessary for surplus at time of use considerations.

E. Surplus Value of ERC Certificate

The emissions continue to be surplus of all District and federal rules and regulations; therefore, no adjustments to the ERC values are necessary.

ERC Certificate N-1568-2 – Criteria Pollutant NOx					
		1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
(A)	Current ERC Quantity	5,000	5,000	5,000	5,000
(B)	Percent Discount	**0%**	**0%**	**0%**	**0%**
(C) = (A) x [1 – (B)]	**Surplus Value**	**5,000**	**5,000**	**5,000**	**5,000**

Attachment

1: Summary of Equipment Shut Down in Original ERC Banking Project

Summary of Equipment Shut Down in Original ERC Banking Project

District Permit	Equipment Summary
N-802-1	COAL FIRED CIRCULATING FLUIDIZED BED BOILER (CAPACITY 550,000 LBS/HR STEAM) UTILIZING LIMESTONE INJECTION FOR SOX CONTROL, A THERMAL DENOX SYSTEM FOR NOX CONTROL, AND TWO CYCLONES VENTED TO A BAGHOUSE FOR PARTICULATE CONTROL
N-802-2	BOTTOM ASH STORAGE AND LOADOUT WITH A WET ROTARY ASH LOADOUT SYSTEM AND DRY ASH FLEXIBLE LOADOUT SPOUT
N-802-3	LIMESTONE RECEIVING AND STORAGE
N-802-4	400 TPH: BELT CONVEYOR #1 AND EN-MASSE CONVEYER #2
N-802-5	STORAGE SILO #1 (3000 TON CAPACITY)
N-802-6	125 TPH COAL CRUSHER, BELT CONVEYOR #3 WITH EN-MASSED CONVEYER #5
N-802-7	PLANT SILO #1 (660 TON CAPACITY)
N-802-8	FLY ASH STORAGE, LOADOUT SYSTEM AND A MIDWEST INDUSTRIES VACULOADER VENTED TO AN INTEGRAL DUST COLLECTOR
N-802-10	COAL/DELAYED COKE RECEIVING SYSTEM
N-802-11	STORAGE SILO #2 (3000 TON CAPACITY)
N-802-12	125 TPH BELT CONVEYOR #4 SERVED BY THE 125 TPH GRINDER (N-802-6) AND BY THE TIRE DERIVED FUEL (TDF) HANDLING EQUIPMENT (N-802-17) VENTED TO BAGHOUSE DC-3
N-802-13	PLANT SILO #2 (660 TON CAPACITY)
N-802-14	FLUID PETROLEUM COKE STORAGE AND HANDLING SYSTEM WITH A 600 TON STORAGE SILO VENTED TO A FLEX-KLEEN WSTS-81 PULSE JET BAGHOUSE
N-802-16	FOUR CELL MECHANICAL DRAFT COOLING TOWER WITH A CIRCULATION RATE OF 25,000 GPM
N-802-17	TIRE DERIVED FUEL (TDF) AND DELAYED COKE RECEIVING AND HANDLING SYSTEM CONSISTING OF THREE COVERED RECEIVING BINS SERVING THREE WALKING FLOOR COVERED TRAILERS AND TWO COVERED TROUGH CONVEYORS SERVING THE EXISTING #4 ENCLOSED SOLID FUEL CONVEYOR
N-802-19	BIOMASS FUEL RECEIVING AND HANDLING OPERATION, INCLUDING THREE TRAILER RECEIVING BAYS AND BIOMASS CONVEYOR #9, ALL SERVED BY A SLY MODEL STJ-85-10 DUST COLLECTOR

San Joaquin Valley Air Pollution Control District
Surplus ERC Analysis

Facility Name:	E & J Gallo Winery	**Date:**	March 10, 2022
Mailing Address:	5610 E Olive Ave Fresno, CA 93727	**Engineer:**	Jesse A. Garcia
		Lead Engineer:	Derek Fukuda
Contact Person:	Kim Burns		
Telephone:	(559) 458-2457		
ERC Certificate #:	C-1404-1		
ERC Surplus Project #:	C-1211601		
ATC Project #:	N-1211986		

I. Proposal

E & J Gallo Winery has requested the District to perform an analysis of the current surplus value of the following Emission Reduction Credit (ERC) certificate:

Proposed ERC Certificate(s)	
Certificate #	**Criteria Pollutant**
C-1404-1	VOC

The purpose of this analysis is to ensure that the emission reductions on this ERC certificate are surplus of all applicable Federal requirements; therefore, this analysis establishes the surplus value of the ERC certificate as of the date of this analysis. The current face value and surplus value of the ERC certificate evaluated in this analysis are summarized in the following table:

Criteria Pollutant Summary: VOC

ERC Certificate C-1404-1				
Pollutant	1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
Current Value	6,369	6,365	5,752	5,631
Surplus Value	1,216	1,216	1,099	1,076

II. Individual ERC Certificate Analysis

<u>ERC Certificate C-1404-1</u>

A. ERC Background

Criteria Pollutant: VOC

ERC Certificate C-1404-1 is a certificate that was split out from parent ERC Certificate C-26-1. Original ERC Certificate C-26-1 was issued to Anderson Clayton Corp on September 13, 1993 under project C-920318. The ERCs were generated from the shutdown of a vegetable oil mill, facility ID C-1897, which included various cottonseed processing operations, a solvent (hexane) extraction operation, and two 21 MMBtu/hr(1) natural gas-fired boilers (see detailed equipment summary in Attachment 1). Of the units shut down, the solvent extraction operation and the two natural gas-fired boilers were the only sources of VOC emissions, therefore, the other permits will not be evaluated as part of this analysis. The following table summarizes the values of the original parent certificate and the current value of the subject certificate proposed to be utilized as a part of the current District analysis:

ERC Certificates C-26-1 and C-1404-1				
Pollutant	1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
Original Value of Parent Certificate C-26-1	30,485	30,519	30,470	30,501
Current Value of ERC Certificate C-1404-1	6,369	6,365	5,752	5,631

B. Applicable Rules and Regulations at Time of Original Banking Project

Based on the application review for the original ERC banking project, the following rules and regulations were evaluated to determine the surplus value of actual emission reductions of VOC generated by the reduction project.

1. District Rules

<u>Rule 220.1 – New and Modified Stationary Source Review Rule (9/19/91)</u>

The application review for the original ERC banking project demonstrated that the equipment was in compliance with the new source review requirements.

(1) Boiler maximum heat input ratings taken from copies of Fresno County APCD permits 1030040110 and 1030040111 included with original ERC banking evaluation.

Rule 230.1 – Emission Reduction Credit Banking (9/19/91)

The application review for the original ERC banking project demonstrated that the ERC complied with the banking requirements at the time it was issued.

Fresno County Rule 409.10 – Vegetable Oil Processing Operations (3/1/88)

The application review for the original ERC banking project demonstrated that equipment was in compliance with the applicable requirements for vegetable oil processing operations.

2. Federal Rules and Regulations

There were no applicable federal rules or regulations identified that applied at the time of this original ERC banking action; therefore, no further discussion is required.

C. New or Modified Rule and Regulations Applicable to the Original Banking Project

All District and federal rules and regulations that have been adopted or amended since the date the original banking project was finalized will be evaluated below:

1. District Rules:

Rule 4305 Boilers, Steam Generators, and Process Heaters – Phase 2 (8/21/03)
Rule 4306 Boilers, Steam Generators, and Process Heaters – Phase 3 (12/17/20)
Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (12/17/20)

The requirements of amended Rule 4305 and new Rules 4306 and 4320 would have been applicable to the boilers that were shut down in the original ERC banking project. However, these rules do not contain any operational requirements or emission limits for VOC emissions. Therefore, the VOC emission reductions are still surplus of the requirements of these rules.

Rule 4691 Vegetable Oil Processing Operations (12/17/92)

The requirements of Rule 4691 would have been applicable to the vegetable oil processing operations that were shut down in the original ERC banking project.

Section 5.1 requires that a person shall not operate any extractor or desolventizer-toaster that emits more than 15 pounds of VOCs per day, (excluding the meal discharge) unless such emissions are controlled by a condenser and mineral oil scrubber with a combined capture and control efficiency of at least 90 percent by weight; or an emission control device, with a combined capture and control efficiency of at least 90 percent by weight.

According to the engineering evaluation for the original banking project, the solvent extraction operations were served by a condenser and a mineral oil scrubber with a source tested control efficiency of 99.4%.

Section 5.2 requires that a person shall not operate a vegetable oil plant unless the desolventizer-toaster discharge conveyor prior to the cooler or tumbler is vented to a mineral oil scrubber having a combined capture and control efficiency of at least 90 percent by weight.

According to a copy of the Permit to Operate included in the engineering evaluation for the original banking project, the meal cooler was part of the solvent extraction equipment served by the mineral oil scrubber.

Sections 5.3 through 5.5 address requirements for VOC leaks from equipment, including the detection threshold, inspections, and repair.

According to a copy of the Permit to Operate included in the engineering evaluation for the original banking project, the equipment was subject to leak standards pursuant to Fresno County Rule 409.10.

As demonstrated above, the equipment that was shut down would have been in compliance with the requirements of this rule. Therefore, the VOC emission reductions are still surplus of the requirements of this rule.

2. Federal Rules and Regulations:

<u>40 CFR Part 60 Subpart Dc - Standards of Performance for Small (10 – 100 MMBtu/hr) Industrial-Commercial-Institutional Steam Generating Units</u>

The requirements of this subpart would be applicable to the boilers that were shut down in the original ERC banking project. However, this subpart does not have any requirements for VOC emissions or any requirements that could affect VOC emissions. Therefore, the VOC emission reductions under evaluation remain surplus of the requirements of this subpart.

<u>40 CFR Part 63 Subpart GGGG - National Emission Standards for Hazardous Air Pollutants: Solvent Extractions for Vegetable Oil Production</u>

Pursuant to §63.2832(a)(1) a vegetable oil production process that is a major source of HAP emissions is subject to the requirements of this subpart. The operation that was shut down had a potential to emit 67.5 tons/year[1] of hexane, and was therefore a major HAP source. The operation would therefore have been subject to the requirements of this subpart.

[1] The permit limit for ROG was 370 lb/day, “(as Hexane)”.

Any adjustments to the surplus value of emission reductions from these units due to the requirements of this rule will be calculated in Section D of this analysis.

40 CFR Part 63 Subpart DDDDD National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

This subpart is applicable to industrial, commercial, or institutional boilers or process heaters that are located at, or are part of, a major source of HAP emissions. However, pursuant to §63.7500(e), there are no emission or operating limits for natural gas-fired boilers and process heaters. The VOC emission reductions under evaluation therefore remain surplus of the requirements of this subpart.

D. Surplus at Time of Use Adjustments to ERC Quantities

As demonstrated in the section above, rules and regulations applicable to permit unit(s) in the original banking project have been adopted or amended since the date the original banking project was finalized. The emissions limits from these new/modified rules and regulations will be compared to the pre and post-project emission limits of each permit unit included in the original banking project to determine any discounting of the original surplus value of emission reductions due to the new/modified rule or regulation.

The amount of ERCs issued from each permit unit in the original banking project, the percentage of that amount which was discounted due to a new/modified rule or regulation, and the current surplus value of the amount of ERCs from each permit unit is calculated in the table(s) below:

Surplus Value Calculations for Solvent Extraction Operation		
(A) Emission Reductions Contributing to ERC	121,536	lb/year
Pre-Project (EF1)	5.33	Compliance Ratio
Post-Project (EF2)	0	Compliance Ratio
Most Stringent Applicable Rule (EF_{Rule}): 40 CFR 63 Subpart GGGG	1.00	Compliance Ratio
(B) Percent Discount*	81.2%	--
Surplus Reductions Contributing to ERC (A) x [1- (B)]	22,849	lb/year

*If $EF_{Rule} \leq EF2$, Percent Discount = 100%, or
If $EF_{Rule} > EF1$, Percent Discount = 0%, otherwise,
$(EF1 – EF_{Rule}) \times 100 \div (EF1 – EF2)$

Section 63.2840 (c) requires that the compliance ratio of the source be less than or equal to 1.00 to demonstrate compliance with the HAP emission requirements. The compliance ratio for this source is calculated using Equation 2 from Section 63.2840(a)(2).

$$\text{Compliance Ratio} = \frac{f * \text{Actual Solvent Loss}}{0.64 * \sum_{i=1}^{n}\left((\text{Oilseed})_i * (\text{SLF})_i\right)} \qquad (Eq.\ 2)$$

Where:

f = The weighted average volume fraction of HAP in solvent received during the previous 12 operating months, as determined in §63.2854, dimensionless.

0.64 = The average volume fraction of HAP in solvent in the baseline performance data, dimensionless.

Actual Solvent Loss = Gallons of actual solvent loss during previous 12 operating months, as determined in §63.2853.

Oilseed = Tons of each oilseed type "i" processed during the previous 12 operating months, as shown in §63.2855.

SLF = The corresponding solvent loss factor (gal/ton) for oilseed "i" listed in Table 1 of this section, as follows:

Compliance Ratio = (1 x 295,625.5 gal/year) ÷ (0.64 x [(cottonseed (tpy) x 0.5) + (safflower (tpy) x 0.7)]
= 295,625.5 ÷ (0.64 x [(106,145) x 0.5) + (47,991 x 0.7)]
= 5.33

Surplus Value Calculations for Natural Gas-Fired Boilers		
(A) Emission Reductions Contributing to ERC	439	lb/year
Pre-Project (EF1)	2.8	lb/MMscf
Post-Project (EF2)	0	lb/MMscf
Most Stringent Applicable Rule (EF_{Rule}): AP-42, Table 1.4-2, 7/98	5.5	lb/MMscf
(B) Percent Discount*	0.0%	--
Surplus Reductions Contributing to ERC (A) x [1- (B)]	439	lb/year

*If EF_{Rule} ≤ EF2, Percent Discount = 100%, or
If EF_{Rule} > EF1, Percent Discount = 0%, otherwise,
(EF1 – EF_{Rule}) x 100 ÷ (EF1 – EF2)

Total Discount Percentage for ERC Certificate

The total percentage ERC C-1404-1 is discounted by due to new and modified rules and regulations is summarized in the following table:

Total Percent Discount Summary for ERC Certificate C-1404-1			
Permit	Amount of ERCs Issued (lb/year)	Percent Discount	Surplus Value (lb/year)
Solvent Usage	121,536	81.2%	22,849
Natural Gas-Fired Boilers	439	0%	439
Total	121,975	--	23,288
Total Percent Discount*		**80.9%**	

* Total Percent Discount = [(Total Amount of ERCs Issued – Total Surplus Value) ÷ Total Amount of ERCs Issued] x 100

E. Surplus Value of ERC Certificate

The emissions continue to be Surplus of all District and Federal Rules and Regulations; therefore, no adjustments to the ERC values are necessary.

ERC Certificate C-1404-1 – Criteria Pollutant VOC					
		1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
(A)	Current ERC Quantity	6,369	6,365	5,752	5,631
(B)	Percent Discount	**80.9%**	**80.9%**	**80.9%**	**80.9%**
(C) = (A) x [1 – (B)]	**Surplus Value**	1,216	1,216	1,099	1,076

Attachment

1: Summary of Equipment Shut Down in Original ERC Banking Project

Summary of Equipment Shut Down in Original ERC Banking Project

Fresno County Permit	Equipment Summary
1030040101	COTTONSEED UNLOADING AND STORAGE FACILITIES
1030040102	COTTONSEED CLEANING AND DELINTING PROCESS
1030040103	COTTONSEED HULLING AND SEPARATING FACILITIES
1030040104	OILSEED SOLVENT EXTRACCTION PLANT EQUIPPED WITH ONE (1) MINERAL OIL SCRUBBER (MOS), CONTROLLING THE EMISSIONS OF VOLATILE ORGANICS (HEXANE) FROM THE EXTRACTION PROCESS
1030040105	COTTONSEED BULK MEAL STORAGE FACILITY
1030040106	COTTONSEED MEAL PROCESSING FACILITY
1030040107	COTTONSEED MEAL LOADING FACILITY
1030040110	ONE (1) DIXON BOILER, 400 BHP, EQUIPPED WITH ONE (1) JOHNSON MODEL 400 BURNER TO BE FIRED WITH NATURAL GAS (PER FRESNO COUNTY PERMIT, MAXIMUM HEAT INPUT RATING WAS 21 MMBTU/HR)
1030040111	ONE (1) KEWANEE BOILER, 400 BHP, EQUIPPED WITH ONE (1) JOHNSON MODEL 400 BURNER TO BE FIRED WITH NATURAL GAS (PER FRESNO COUNTY PERMIT, MAXIMUM HEAT INPUT RATING WAS 21 MMBTU/HR)

San Joaquin Valley Air Pollution Control District
Surplus ERC Analysis

Facility Name: E & J Gallo Winery
Mailing Address: 5610 E Olive Ave
Fresno, CA 93727
Contact Person: Kim Burns
Telephone #: (559) 458-2457
ERC Certificate #s: S-4442-1, S-4751-1, and S-4773-1
ERC Surplus Project #: S-1213354
ATC Project #: N-1211986

Date: March 10, 2022
Engineer: Jesse A. Garcia
Lead Engineer: Derek Fukuda

I. Proposal

E & J Gallo Winery has requested the District to perform an analysis of the current surplus value of the following Emission Reduction Credit (ERC) certificates:

Proposed ERC Certificates	
Certificate #	**Criteria Pollutant**
S-4442-1	VOC
S-4751-1	VOC
S-4773-1	VOC

The purpose of this analysis is to ensure that the emission reductions on these ERC certificates are surplus of all applicable Federal requirements; therefore, this analysis establishes the surplus value of the ERC certificate as of the date of this analysis. The current face values and surplus values of the ERC certificates evaluated in this analysis are summarized in the following table:

Criteria Pollutant Summary: VOC

ERC Certificate S-4442-1				
Pollutant	1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
Current Value	7,039	7,032	7,025	7,013
Surplus Value	296	295	295	295

ERC Certificate S-4751-1				
Pollutant	1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
Current Value	14,349	14,341	16,065	16,065
Surplus Value	603	602	675	675

ERC Certificate S-4773-1				
Pollutant	1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
Current Value	827	771	56	41
Surplus Value	35	32	2	2

II. Individual ERC Certificate Analysis

<u>ERC Certificate S-4948-1</u>

A. ERC Background

Criteria Pollutant: VOC

ERC Certificates S-4442-1, S-4751-1, and S-4773-1 are certificates that were split out from parent ERC Certificate S-47-1. Original ERC Certificate S-47-1 was issued to Frito-Lay, Inc. (Facility S-1637) on March 1, 1993 under project S-920416. The ERCs were generated from the shutdown of a carbon black production facility, which included two production units with reactors, pulverizers and pelletizers, dryers, screens and separators, storage vessels, and bagging and loadout equipment (see equipment summary in Appendix A). Of the units shut down, the reactors (main process vents) and oil storage tank were the only sources of the VOC reductions banked. Therefore, the other units will not be evaluated as part of this analysis. The following table summarizes the values of the original parent certificate and the current values of the subject certificates proposed to be utilized as a part of the current District analysis:

ERC Certificates S-47-1, S-4442-1, S-4751-1, and S-4773-1				
Pollutant	1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
Original Value of Parent Certificate S-47-1	229,968	232,523	235,078	235,078
Current Value of ERC Certificate S-4442-1	7,039	7,032	7,025	7,013
Current Value of ERC Certificate S-4751-1	14,349	14,341	16,065	16,065
Current Value of ERC Certificate S-4773-1	827	771	56	41

B. Applicable Rules and Regulations at Time of Original Banking Project

Based on the application review for the original ERC banking project, the following rules and regulations were evaluated to determine the surplus value of actual VOC emission reductions generated by the reduction project.

1. District Rules

Rule 220.1 – New and Modified Stationary Source Review
Rule 230.1 – Emission Reduction Credit Banking

The application review for the original ERC banking project demonstrated that the ERC credit complied with the requirements of these rules at the time it was issued.

2. Federal Rules and Regulations

There were no applicable federal rules or regulations identified that applied at the time of this original ERC banking action; therefore, no further discussion is required.

C. New or Modified Rule and Regulations Applicable to the Original Banking Project

All District and federal rules and regulations that have been adopted or amended since the date the original banking project was finalized will be evaluated below:

1. District Rules:

Rule 2201 – New and Modified Stationary Source Review (8/15/2019)
Rule 2301 – Emission Reduction Credit Banking (8/15/2019)

District Rules 220.1 and 230.1 have been renamed 2201 and 2301, respectively, and amended, since the original ERC certificate was issued. However, the requirements of these rules only applied at the time of the original banking action. Thus, no further evaluation of these rules will be conducted in this analysis.

Rule 4623 – Storage of Organic Liquids (5/19/05)

Except for testing and recordkeeping, tanks exclusively receiving and/or storing an organic liquid with a TVP less than 0.5 psia are exempt from the requirements this rule. The feedstock for carbon black manufacturing is typically fuel/residual oils. According to Appendix A of the rule, the TVP for these oils does not exceed 0.5 psia at storage temperatures below 195 ^{o}F. Therefore, the storage of the feedstock oil under normal circumstances (i.e. unheated) would not have been subject to the requirements of this rule. The VOC emission reductions under evaluation remain surplus of the requirements of this rule.

2. Federal Rules and Regulations:

40 CFR Part 63 Subpart YY – National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards

The main HAPs from carbon black production operations are carbon disulfide and carbonyl sulfide. According to AP-42 (Table 6.1-2) the oil furnace production method emits these HAPs at the rates of 60 lb/ton and 20 lb/ton, respectively. According to the original ERC banking evaluation, this facility used the oil furnace production method, and the average production rate during the baseline period was 71.63 tons/day. An emissions control system with a 29.5% efficiency was in use. Thus, the facility's carbon disulfide and carbonyl sulfide emissions during the baseline period were 553 tons/yr and 184 tons/yr, respectively.[1] The facility was therefore a major HAP source.

Pursuant to §63.1103(f)(3), the following requirements are applicable to carbon black production process vents:

Table 8 to §63.1103(f) - What Are My Requirements if I Own or Operate a Carbon Black Production Existing or New Affected Source?		
If you own or operate . . .	**And if . . .**	**Then you must . . .**
(a) A carbon black production main unit filter process vent	(1) The HAP concentration of the emission stream is equal to or greater than 260 parts per million by volume	(i) Reduce emissions of HAP by using a flare meeting the requirements of subpart SS of this part; or (ii) Reduce emissions of total HAP by 98 weight-percent or to a concentration of 20 parts per million by volume, whichever is less stringent, by venting emissions through a closed vent system to any combination of control devices meeting the requirements of §63.982(a)(2).

Due to unavailability of the original facility documents, the HAP concentration of the emission stream cannot be readily ascertained. However, in light of the known scale of the operation, it is conservatively assumed that the HAP concentration would have been greater than 260 ppmv.[2] Also, since the HAP concentration of the emission stream cannot be ascertained, only the 98% reduction option can be used in this analysis.[3]

Pursuant to §63.1100(a) (Table 1), the requirements of this subpart are not applicable to storage vessels or equipment leaks in the carbon black source category.

Any adjustments to the surplus value of the original emission reductions due to the requirements of this subpart will be calculated in Section D of this analysis.

[1] (Emission rate, lb/ton) x (71.63 tons/day) x (365 days/yr) x (1 - 0.295) / (2,000 lb/ton) = (Emissions, tons/yr)
[2] Note for instance that the controlled average **daily** emission rate for VOC during the baseline period was 4,776.6 lb.
[3] 98% reduction is the less stringent option for HAP concentrations > 1,000 ppmv, which is the more likely case given the previously cited scale of the operation.

D. Surplus at Time of Use Adjustments to ERC Quantities

As demonstrated in the section above, rules and regulations applicable to permit unit(s) in the original banking project have been adopted or amended since the date the original banking project was finalized. The emissions limits from these new/modified rules and regulations will be compared to the pre and post-project emission limits of each permit unit included in the original banking project to determine any discounting of the original surplus value of emission reductions due to the new/modified rule or regulation.

The amount of ERCs issued from each permit unit in the original banking project, the percentage of that amount which was discounted due to a new/modified rule or regulation, and the current surplus value of the amount of ERCs from each permit unit is calculated in the table(s) below:

Surplus Value Calculations for Reactor Main Process Vents		
(A) Emission Reductions Contributing to ERC	919,409	lb/year
Pre-Project (EF1)	0.705	1 - CE
Post-Project (EF2)	0	1 - CE
Most Stringent Applicable Rule (EF_{Rule}): 40 CFR 63 Subpart YY, §63.1103(f)(3)	0.02	1 - CE
(B) Percent Discount*	97.2%	--
Surplus Reductions Contributing to ERC (A) x [1- (B)]	25,743	lb/year

*If EF_{Rule} ≤ EF2, Percent Discount = 100%, or
If EF_{Rule} > EF1, Percent Discount = 0%, otherwise,
(EF1 – EF_{Rule}) x 100 ÷ (EF1 – EF2)

Surplus Value Calculations for Oil Storage Tank Vent		
(A) Emission Reductions Contributing to ERC	13,239	lb/year
Pre-Project (EF1)	1.44	lb/ton
Post-Project (EF2)	0	lb/ton
Most Stringent Applicable Rule (EF_{Rule}): RACT	1.44	lb/ton
(B) Percent Discount*	0.0%	--
Surplus Reductions Contributing to ERC (A) x [1- (B)]	13,239	lb/year

*If EF_{Rule} ≤ EF2, Percent Discount = 100%, or
If EF_{Rule} > EF1, Percent Discount = 0%, otherwise,
(EF1 – EF_{Rule}) x 100 ÷ (EF1 – EF2)

Total Discount Percentage for ERC Certificate

The total percentage ERC S-47-1 is discounted by due to new and modified rules and regulations is summarized in the following table:

Total Percent Discount Summary for ERC Certificate S-47-1			
Permit(s)	Amount of ERCs Issued (lb/year)	Percent Discount	Surplus Value (lb/year)
Reactor Main Process Vents	919,409	97.2%	25,743
Oil Storage Tank Vent	13,239	0%	13,239
Total	932,648	--	38,982
Total Percent Discount*		**95.8%**	

* Total Percent Discount = [(Total Amount of ERCs Issued – Total Surplus Value) ÷ Total Amount of ERCs Issued] x 100

E. Surplus Value of ERC Certificate

As shown in the previous section, the surplus at time of use values of these ERC certificates will be adjusted. The current face values of the ERC certificates, the percent the current values are discounted by based on the surplus analysis in the previous section, and the current calculated surplus values of the ERC certificates are shown in the tables below:

ERC Certificate S-4442-1 – Criteria Pollutant VOC					
		1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
(A)	Current ERC Quantity	7,039	7,032	7,025	7,013
(B)	Percent Discount	**95.8%**	**95.8%**	**95.8%**	**95.8%**
(C) = (A) x [1 – (B)]	**Surplus Value**	**296**	**295**	**295**	**295**

…

ERC Certificate S-4751-1 – Criteria Pollutant VOC					
		1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
(A)	Current ERC Quantity	14,349	14,341	16,065	16,065
(B)	Percent Discount	**95.8%**	**95.8%**	**95.8%**	**95.8%**
(C) = (A) x [1 – (B)]	**Surplus Value**	**603**	**602**	**675**	**675**

ERC Certificate S-4773-1 – Criteria Pollutant VOC					
		1st Qtr. (lb/qtr)	2nd Qtr. (lb/qtr)	3rd Qtr. (lb/qtr)	4th Qtr. (lb/qtr)
(A)	Current ERC Quantity	827	771	56	41
(B)	Percent Discount	**95.8%**	**95.8%**	**95.8%**	**95.8%**
(C) = (A) x [1 – (B)]	**Surplus Value**	**35**	**32**	**2**	**2**

Appendix A

Summary of Equipment Shut Down in Original ERC Banking Project

Appendix A

Summary of Equipment Shut Down in Original ERC Banking Project	
Kern County Permit #	**Equipment Description**
6026001	Unit 1 Reactors
6026002	Unit 1 Pulverizer/Pelletizers
6026003	Unit 1 Dryer
6026004	Unit 1 Screens/Separators/Storage/Bagging/Loadout
6026005	Unit 2 Reactors
6026006	Unit 2 Pulverizer/Pelletizers
6026007	Unit 2 Dryer
6026008	Unit 2 Screens/Separators/Storage/Bagging/Loadout

APPENDIX I

ERC Withdrawal Calculations

ERC Withdrawal Calculations for NO_X

NO_X	1st Quarter (lb)	2nd Quarter (lb)	3rd Quarter (lb)	4th Quarter (lb)
Total Surplus NO_X Offsets Required (Includes distance offset ratio)	727	727	728	728

NO_X ERCs from N-1568-2	1st Quarter (lb)	2nd Quarter (lb)	3rd Quarter (lb)	4th Quarter (lb)
Nominal Value of ERC N-1568-2	5,000	5,000	5,000	5,000
ERC N-1568-2 Surplus Value	5,000	5,000	5,000	5,000
ERC N-1568-2 Surplus Value Percent Discount	0%	0%	0%	0%
Surplus Offsets Used from ERC N-1568-2 Including Surplus Discount	727	727	728	728
Total Offsets Used from ERC N-1568-2 Including Surplus Discount	727	727	728	728
Remaining Credits from ERC N-1568-2 to be reissued to Facility	4,273	4,273	4,272	4,272

ERC Withdrawal Calculations for VOC

VOC	1st Quarter (lb)	2nd Quarter (lb)	3rd Quarter (lb)	4th Quarter (lb)
Total Surplus VOC Offsets Required (Includes distance offset ratio)	682	682	683	683

E & J Gallo Winery states that they would like to use the ERC certificate S-4751-1 first. ERC certificate S-4751-1 has already been partially reserved for other projects; therefore, only the remaining unreserved amount can be used for this project. The ERC offsetting proposal below is based on this request.

VOC ERCs from S-4751-1	1st Quarter (lb)	2nd Quarter (lb)	3rd Quarter (lb)	4th Quarter (lb)
ERC S-4751-1	14,349	14,341	16,065	16,065
ERC S-4751-1 Surplus Value	603	602	675	675
ERC S-4751-1 Surplus Value Percent Discount	95.8%	95.8%	95.8%	95.8%
Surplus Offsets Used from ERC S-4751-1 Including Surplus Discount	189	187	227	202
Total Offsets Used from ERC S-4751-1 Including Surplus Discount	4,498	4,451	5,416	4,808
Remaining Credits from ERC S-4751-1 to be reissued to Facility	9,851	9,890	10,649	11,257

VOC ERCs from C-1404-1	1st Quarter (lb)	2nd Quarter (lb)	3rd Quarter (lb)	4th Quarter (lb)
ERC C-1404-1	6,369	6,365	5,752	5,631
ERC C-1404-1 Surplus Value	1,216	1,216	1,099	1,076
ERC C-1404-1 Surplus Value Percent Discount	80.9%	80.9%	80.9%	80.9%
Surplus Offsets Used from ERC C-1404-1 Including Surplus Discount	493	495	456	481
Total Offsets Used from ERC C-1404-1 Including Surplus Discount	2,581	2,592	2,387	2,518
Remaining Credits from ERC C-1404-1 to be reissued to Facility	3,788	3,773	3,365	3,113

APPENDIX J

Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) Memo

San Joaquin Valley Air Pollution Control District
Risk Management Review and Ambient Air Quality Analysis

To:	Dan Klevann – Permit Services
From:	Adrian Ortiz – Technical Services
Date:	July 9, 2021
Facility Name:	E & J GALLO WINERY
Location:	18000 W RIVER RD, LIVINGSTON
Application #(s):	N-1237-892-0
Project #:	N-1211986

1. Summary

1.1 RMR

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
892-0	0.76	0.06	0.01	3.23E-07	No	Yes
Project Totals	0.76	0.06	0.01	3.23E-07		
Facility Totals	>1	0.26	0.10	9.25E-07		

1.2 AAQA

Pollutant	Air Quality Standard (State/Federal)				
	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass		Pass		
NO_x	Pass				Pass
SO_x	Pass	Pass		Pass	Pass
PM10				Pass	Pass
PM2.5				Pass	Pass

Notes:
1. Results were taken from the attached AAQA Report.
2. The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2) unless otherwise noted below.
3. Modeled PM10 concentrations were below the District SIL for non-fugitive sources of 5 μg/m^3 for the 24-hour average concentration and 1 μg/m^3 for the annual concentration.
4. Modeled PM2.5 concentrations were below the District SIL for non-fugitive sources of 1.2 μg/m^3 for the 24-hour average concentration and 0.2 μg/m^3 for the annual concentration.

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

<u>Unit # 892-0</u>

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. Project Description

Technical Services received a request on June 17, 2021 to perform a Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) for the following:

- Unit -892-0: Installation of one new 1,966 bhp Jenbacher model JMC420 natural gas or digester gas-fired IC engine served by a Steuler selective catalytic reduction system and an oxidation catalyst powering an electrical generator.

3. RMR Report

3.1 Analysis

The District performed an analysis pursuant to the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015) to determine the possible cancer and non-cancer health impact to the nearest resident or worksite. This policy requires that an assessment be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold

Then, generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than 1.0. If a preliminary analysis demonstrates that either the unit's or the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required

If a refined assessment is greater than one in a million but less than 20 in one million for carcinogenic impacts (Cancer Risk) and less than 1.0 for the Acute and Chronic hazard indices(Non-Carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For unit's that exceed a cancer risk of 1 in one million, Toxic Best Available Control Technology (TBACT) must be implemented.

Toxic emissions for this project were calculated using the following methods:

- Toxic emissions for this proposed unit were calculated using Digester Gas Fired Internal Combustion Engine emission factors derived from the 2002 Reciprocating Internal Combustion Engine (RICE) EPA database.

These emissions were input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy, risks from the proposed unit's toxic emissions were prioritized using the procedure in the 2016 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 2013-2017 from Modesto (rural dispersion coefficient selected) 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:

Source Process Rates					
Unit ID	**Process ID**	**Process Material**	**Process Units**	**Hourly Process Rate**	**Annual Process Rate**
892-0	1	Digester Gas	MMscf	0.02	148

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
892-0	1966 BHP Digester Gas IC Engine	10.67	728	10.08	0.46	Vertical

4. AAQA Report

The District modeled the impact of the proposed project on the National Ambient Air Quality Standard (NAAQS) and/or California Ambient Air Quality Standard (CAAQS) in accordance with District Policy APR-1925 (Policy for District Rule 2201 AAQA Modeling) and EPA's Guideline for Air Quality Modeling (Appendix W of 40 CFR Part 51). The District uses a progressive three level approach to perform AAQAs. The first level (Level 1) uses a very conservative approach. If this analysis indicates a likely exceedance of an AAQS or Significant Impact Level (SIL), the analysis proceeds to the second level (Level 2) which implements a more refined approach. For the 1-hour NO_2 standard, there is also a third level that can be implemented if the Level 2 analysis indicates a likely exceedance of an AAQS or SIL.

The modeling analyses predicts the maximum air quality impacts using the appropriate emissions for each standard's averaging period. Required model inputs for a refined AAQA include background ambient air quality data, land characteristics, meteorological inputs, a receptor grid, and source parameters including emissions. These inputs are described in the sections that follow.

Ambient air concentrations of criteria pollutants are recorded at monitoring stations throughout the San Joaquin Valley. Monitoring stations may not measure all necessary pollutants, so background data may need to be collected from multiple sources. The following stations were used for this evaluation:

Monitoring Stations				
Pollutant	**Station Name**	**County**	**City**	**Measurement Year**
CO	Modesto-14th Street	Stanislaus	Modesto	2018
NOx	Turlock	Stanislaus		2018
PM10	Turlock	Stanislaus		2018
PM2.5	Turlock	Stanislaus		2018
SOx	Fresno - Garland	Fresno	Fresno	2018

Technical Services performed modeling for directly emitted criteria pollutants with the emission rates below:

Emission Rates (lbs/hour)						
Unit ID	**Process**	**NOx**	**SOx**	**CO**	**PM10**	**PM2.5**
892-0	1	4.50	0.04	0.60	0.14	0.14

Emission Rates (lbs/year)						
Unit ID	**Process**	**NOx**	**SOx**	**CO**	**PM10**	**PM2.5**
892-0	1	1,990	342	5,256	1,201	1,201

The AERMOD model was used to determine if emissions from the project would cause or contribute to an exceedance of any state of federal air quality standard. The parameters outlined below and meteorological data for 2013-2017 from Modesto (rural dispersion coefficient selected) were used for the analysis:

The following parameters were used for the review:

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
892-0	1966 BHP Digester Gas IC Engine	10.67	728	10.08	0.46	Vertical

5. Conclusion

5.1 RMR

The cumulative acute and chronic indices for this facility, including this project, are below 1.0; and the cumulative cancer risk for this facility, including this project, is less than 20 in a million. In addition, the cancer risk for each unit in this 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.

5.2 AAQA

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

6. Attachments

A. Modeling 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 results

APPENDIX K

E & J Gallo Winery Compliance Certification

N-1237

E&J Gallo Winery-Livingston

Project: 3rd Internal Combustion Engine (ICE)

Install 1429 KW OR 1141 KW Jenbacher Cogeneration Unit

District Permitting Engineer: Mr. Dustin Brown

Compliance Certification Statement

For Federal Major Permit Modifications

Compliance with District Rule 2201, Section 4.15.2

"I certify under penalty of law that all major stationary sources (Title V facilities) operated under my control in California are compliant with all applicable air emissions limitations and standards. The facilities included in this certification statement include the following: E&J Gallo Winery-Fresno (includes California Natural Colors); E&J Gallo Winery-Livingston; E&J Gallo Winery-Modesto (includes Spirits facility) and Gallo Glass."

Mr. Chris Savage | 5/19/21
Sr. Director of Global | Date
Environmental Health and Safety

APPENDIX L

Facility NOx, SOx, PM10 and CO Emission Summaries and Calculations

As discussed in Section VII.C.3 of this document above, E & J Gallo Winery has acknowledged that their facility emissions are already above the Offset and Major Source Thresholds for VOC emissions. Therefore, facility emission calculations for VOC emissions are not necessary and will not be performed for this project.

Based upon a review of the permit units operated at this facility, the following permits are the only units at the facility that emit pollutants other than VOC emissions.

SSPE1 Emission Calculations:

The following methodology will be used to determine the PEs used to calculate the SSPE1.

- For permit units issued in ATC projects finalized > 5 years prior to the complete date of this project, the PE for the permit unit shall be recalculated and the recalculated value shall be used in the SSPE1 calculation.
- For permit units issued in ATC projects finalized < 5 years prior to the complete date of this project, the PE calculated in the ATC project will be used in the SSPE1 calculation.

N-1237-1-3 (pneumatic conveyor and bulk storage):

No data is available for this unit to determine potential emissions. Since the hammer mill operation listed under permit N-1237-5 is expected to have higher emissions than this operation, the potential emissions from that unit will be used for this operation. See N-1237-5-3 for PE calculation details.

PM_{10} PE = 786 lb-PM_{10}/year

N-1237-4-14 (150 MMBtu/hr natural gas-fired boiler):

The following emissions were calculated in the evaluation performed as a part of project N-1162250 (final June 23, 2016) for this facility:

NO_X PE = 12,976 lb-NO_X/year
SO_X PE = 3,745 lb-SO_X/year
PM_{10} PE = 6,750 lb-PM_{10}/year
CO PE = 194,472 lb-CO/year

N-1237-5-3 (hammer mill):

This permit does not contain emission factor and process throughput. Therefore, emission inventory data (i.e. both emission factor and process throughput) submitted on 5/31/12 is utilized. The applicant requested to retain this data CONFIDENTIAL. Therefore, calculation methodology and the calculated potential emissions are listed here. The reported process throughput is increased by 50% to determine the potential emissions.

PM_{10} PE = 786 lb-PM_{10}/year

N-1237-6-4: (diatomaceous earth receiving and storing operation

Assumptions:

- Annual operating schedule = 365 days/year (worst case)
- Maximum throughput = 75 tons/day (current permit)
- Emission Factor = 0.003 lb-PM_{10}/ton (current permit)

Calculations:

PM_{10} PE = (0.003 lb-PM_{10}/ton) x (75 tons/day) x (365 day/year) **= 82 lb-PM_{10}/year**

N-1237-7-3, '-8-3, '-9-3, and '-10-3 (abrasive blasting operations):

Abrasive blasting units.

§41905 of the California Health and Safety Code states that "the (state) standards, however, shall not supersede any rule or regulation of any district governing permanent sandblasting operation or equipment, which rule or regulation was in effect on January 1, 1974."

All new source review rules in the eight counties in the District were adopted after January 1, 1974. Therefore, the NSR requirements shall not apply to abrasive blasting operations conducted within the District.

In determining the NSR requirements, the emissions from abrasive blasting operations shall be excluded from the stationary source emissions. Therefore, the PE values for these units will be set equal to zero.

N-1237-12-4 (oak chip roasting operation with 3 MMBtu/hr LPG-fired incinerator):

The following emissions were calculated in the evaluation performed as a part of project N-1162250 (final June 23, 2016) for this facility:

NO_X PE = 3,734 lb-NO_X/year
SO_X PE = 431 lb-SO_X/year
PM_{10} PE = 146 lb-PM_{10}/year
CO PE = 2,154 lb-CO/year

N-1237-17-3 (oak wood chip transfer system):

The following emissions were calculated in the evaluation performed as a part of project N-1162250 (final June 23, 2016) for this facility:

PM_{10} PE = 657 lb-PM_{10}/year

N-1237-480-5 (diatomaceous earth receiving and storage operation):

The following emissions were calculated in the evaluation performed as a part of project N-1162250 (final June 23, 2016) for this facility:

PM_{10} PE = 14 lb-PM_{10}/year

N-1237-596-5 (oak sawdust handling system):

The following emissions were calculated in the evaluation performed as a part of project N-1182636 (final October 29, 2018) for this facility:

PM_{10} PE =120 lb-PM_{10}/year

N-1237-601-2 (diatomaceous earth receiving and storage operation):

The following emissions were calculated in the evaluation performed as a part of project N-1162250 (final June 23, 2016) for this facility:

PM_{10} PE = 7 lb-PM_{10}/year

N-1237-603-4 (oak sawdust handling system):

The following emissions were calculated in the evaluation performed as a part of project N-1162250 (final June 23, 2016) for this facility:

PM_{10} PE = 115 lb-PM_{10}/year

N-1237-605-3 and -606-2 (IC engine):

The following emissions were calculated in the evaluation performed as a part of project N-1182551 (final December 10, 2018) for this facility for each unit:

NO_X PE = 3,869 lb-NO_X/year
SO_X PE = 645 lb-SO_X/year
PM_{10} PE = 851 lb-PM_{10}/year
CO PE = 20,637 lb-CO/year

N-1237-607-3 (90 MMBtu/hr natural gas-fired boiler):

The emissions from this boiler will be determined using the permitted emission factors/rates, the maximum heat input rating of the boiler, and a worst-case operating schedule of 365 days/year.

NO_X PE = 5,256 lb-NO_X/year (per current permit)

SO_X PE = (0.00285 lb-SO_X/MMBtu) x (90 MMBtu/hr) x (24 hr/day) x (365 day/year)
= 2,247 lb-SO_X/year

PM_{10} PE = (0.0076 lb-PM_{10}/MMBtu) x (90 MMBtu/hr) x (24 hr/day) x (365 day/year)
= 5,992 lb-PM_{10}/year

CO PE = (0.148 lb-CO/MMBtu) x (90 MMBtu/hr) x (24 hr/day) x (365 day/year)

= 116,683 lb-CO/year

<u>N-1237-661-3 (digester gas operation with a 32.4 MMBtu/hr emergency flare):</u>

The following emissions were calculated in the evaluation performed as a part of project N-1152892 (final December 22, 2015) for this facility:

NO_X PE = 389 lb-NO_X/year
SO_X PE = 49 lb-SO_X/year
PM_{10} PE = 52 lb-PM_{10}/year
CO PE = 4,860 lb-CO/year

<u>N-1237-694-1 (green waste material receiving, storage, and mixing operation):</u>

The emissions from this operation will be determined using the permitted emission factors and rates and the methodology used in the original permitting project, N-1121070.

<u>Assumptions:</u>

- Maximum facility throughput = 100,000 tons/year (current permit)
- Emission Factor = 0.00033 lb-PM_{10}/ton (current permit)
- Emission Factor = 0.318 lb-NH_3/ton (current permit)
- 5 drop points (per project N-1121070)
- 10 storage day (per project N-1121070)

<u>Calculations:</u>

PM_{10} PE = (0.00033 lb-PM_{10}/ton) x (100,000 tons/year) x (5 drop points)
= 165 lb-PM_{10}/year
NH_3 PE = (0.318 lb-NH_3/ton) x (100,000 tons/year) x (10 storage days)
= 31,800 lb-NH_3/year

<u>N-1237-695-1 (green waste composting operation):</u>

The emissions from this operation will be determined using the permitted emission factors and rates and the methodology used in the original permitting project, N-1121070.

<u>Assumptions:</u>

- Maximum facility throughput = 100,000 tons/year (current permit)
- Emission Factor = 0.00033 lb-PM_{10}/ton (current permit)
- Emission Factor = 1.108 lb-NH_3/ton (per project N-1121070)
- 2 drop points (per project N-1121070)
- 10 storage day (per project N-1121070)

<u>Calculations:</u>

PM_{10} PE = (0.00033 lb-PM_{10}/ton) x (100,000 tons/year) x (2 drop points)
= 66 lb-PM_{10}/year

NH_3 PE = (1.108 lb-NH_3/ton) x (100,000 tons/year) **= 110,800 lb-NH_3/year**

N-1237-696-1 (finished compost storage and load out operation):

The emissions from this operation will be determined using the permitted emission factors and rates and the methodology used in the original permitting project, N-1121070.

Assumptions:
- Maximum throughput = 55,000 tons/year (per project N-1121070)
- Emission Factor = 0.00033 lb-PM_{10}/ton (per project N-1121070)
- 2 drop points (per project N-1121070)

Calculations:

PM_{10} PE = (0.00033 lb-PM_{10}/ton) x (55,000 tons/year) x (2 drop points) **= 36 lb-PM_{10}/year**

N-1237-762-3 and (oak handling system):

The following emissions were calculated in the evaluation performed as a part of project N-1182636 (final October 29, 2018) for this facility:

PM_{10} PE =120 lb-PM_{10}/year

N-1237-763-2 (grape pomace and wine solids drying operation):

The emissions from this operation will be determined using the permitted emission factors and rates.

Assumptions:
- Maximum operating schedule = 365 days/year (worst case)
- Maximum throughput = 168 tons/day (current permit)
- Emission Factor = 0.00052 lb-PM_{10}/ton (current permit)

Calculations:

PM_{10} PE = (0.00052 lb-PM_{10}/ton) x (168 tons/day) x (365 days/year)
= 32 lb-PM_{10}/year

N-1237-781-2 and '-782-2 (carbon delivery systems A and B):

The emissions for these two identical carbon delivery systems will be determined using the permitted emission factors and rates.

Assumptions:
- Maximum throughput = 150,000 lbs/year (current permits)
- Emission Factor = 0.02 lb-PM_{10}/ton (current permits)

Calculations:

PM_{10} PE = (0.02 lb-PM_{10}/ton) x (150,000 lbs/year) ÷ (2,000 lbs/ton) **= 15 lb-PM_{10}/year**

N-1237-786-0 (mobile carbon delivery system C):

The emissions for this operation will be determined using the permitted emission factors and rates.

Assumptions:
- Maximum throughput = 75 tons/year (current permit)
- Emission Factor = 0.2 lb-PM_{10}/ton (current permit)

Calculations:

PM_{10} PE = (0.2 lb-PM_{10}/ton) x (75 tons/year) **= 15 lb-PM_{10}/year**

N-1237-787-1 (85 bhp diesel-fired emergency IC engine):

The following emissions were calculated in the evaluation performed as a part of project N-1162250 (final June 23, 2016) for this facility:

NO_X PE = 28 lb-NO_X/year
SO_X PE = 0 lb-SO_X/year
PM_{10} PE = 1 lb-PM_{10}/year
CO PE = 25 lb-CO/year

Emission Summary:

Emission Summary				
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**
N-1237-4-14	12,976	3,745	6,570	194,472
N-1237-5-3	0	0	786	0
N-1237-6-4	0	0	82	0
N-1237-7-3	0	0	0	0
N-1237-8-3	0	0	0	0
N-1237-9-3	0	0	0	0
N-1237-10-3	0	0	0	0
N-1237-12-4	3,734	431	146	2,154
N-1237-17-3	0	0	657	0
N-1237-480-5	0	0	14	0
N-1237-596-4	0	0	120	0
N-1237-601-2	0	0	7	0
N-1237-603-4	0	0	115	0
N-1237-607-1	5,260	2,247	5,992	116,683
N-1237-661-3	389	49	52	4,860
N-1237-694-1*	0	0	165	0
N-1237-695-1	0	0	66	0

N-1237-696-1	0	0	36	0
N-1237-762-3	0	0	120	0
N-1237-763-2	0	0	32	0
N-1237-781-2	0	0	15	0
N-1237-782-2	0	0	15	0
N-1237-786-0	0	0	15	0
N-1237-787-0	28	0	1	25
Total	**22,387**	**6,472**	**15,006**	**318,194**