San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

December 8, 2023

Jarrett Hollis
Aemetis Advanced Products
20400 Stevens Creek Blvd, Ste. 700
Cupertineo, CA 95014

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: N-9742
Project Number: N-1224324

Dear Mr. Hollis:

Enclosed for your review and comment is the District's analysis of Aemetis Advanced Products's application for an Authority to Construct for a biofuel production plant, at 5300 Claus Road in Riverbank, CA.

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 period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

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

Sincerely,

Brian Clements
Director of Permit Services

BC:JH

Enclosures

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

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

Renewable Diesel and Sustainable Aviation Fuel Plant

Facility Name:	Aemetis Advanced Products Riverbank	Date:	December 8, 2023
Mailing Address:	20400 Stevens Creek Blvd Suite 700 Cupertino, CA 95014	Engineer: Lead Engineer:	James Harader Nick Peirce
Contact Person:	Jarret Hollis		
Telephone:	(209) 277-5948		
E-Mail:	Jarrett.hollis@aemetis.com		
Application #(s):	N-9742-20-0 through ‘-32-0		
Project #:	N-1224324		
Deemed Complete:	February 3, 2023		
CEQA Complete:	September 21, 2023		

I. Proposal

Aemetis Advanced Products Riverbank, Inc. (“Aemetis”) has proposed to install a sustainable aviation and renewable diesel production plant in Riverbank, California. The facility will produce 120,000,000 gallons per year of sustainable aviation fuel and renewable diesel from vegetable oils and rendered animal fats. The production plant will include the following equipment:

Permit Exempt Feedstock Storage and Blending Tanks and Pre-Treatment Operations

The applicant is proposing to install feedstock storage and blending tanks that will store and blend the raw materials (animal fats and vegetable oils). The feedstock will then be fed through a pre-treatment unit to remove impurities prior to processing in the HydroFlex fuel production unit. The feedstock storage and blending tanks, and the pretreatment unit do not emit any air contaminants; therefore, a permit is not required for this equipment. For more details on this determination, please refer to the Rule 2010 discussion in the compliance section of this document.

N-9742-20-0: HydroFlex Fuel Production Unit (HFU)

The applicant is proposing to install a HydroFlex fuel production unit with a hydrogenation reactor, gas and liquid separation equipment, a 19.5 MMBtu/hr natural gas-fired process heater, a 27.6 MMBtu/hr natural gas-fired process heater, and a 41.5 MMBtu/hr natural gas-fired process heater. (88.6 MMBtu/hr total)

N-9742-21-0: Hydrogen Production Unit (HPU)

The applicant is proposing to install a hydrogen production unit with a hydrotreater, desulfurization absorber, pre-reformer, reformer, pressure swing adsorber, and a 184 MMBtu/hr process gas and natural gas fired heater. Vapors from the hydrogen production unit will be vented to a shared regenerative thermal oxidizer (RTO #1 shared with N-9742-24).

N-9742-22-0: Boiler

The applicant is proposing to install a 59 MMBtu/hr natural gas-fired auxiliary boiler.

N-9742-23-0: Material Transfer Operation

The applicant is proposing to install a material transfer operation served by a regenerative thermal oxidizer (RTO #2).

N-9742-24-0: Wastewater Treatment Unit

The applicant is proposing to install a wastewater treatment unit served by a shared regenerative thermal oxidizer (RTO #1 shared with N-9742-21).

N-9742-25-0: Cooling Tower

The applicant is proposing to install a 3-cell cooling tower with a mist eliminator.

N-9742-26-0: Emergency Flare

The applicant is proposing to install a 79.17 MMBtu/hr process-gas fired emergency flare.

N-9742-27-0: Emergency Firewater Pump

The applicant is proposing to install a 687 BHP Tier 3 certified diesel-fired emergency IC engine powering a firewater pump.

N-9742-28-0: Emergency Electrical Generator

The applicant is proposing to install a 1,341 BHP Tier 4F certified diesel-fired emergency IC engine powering an electrical generator.

N-9742-29-0: Naphtha Storage Tank #1

The applicant is proposing to install a 203,700 gallon Naphtha internal floating roof storage tank.

N-9742-30-0: Naphtha Storage Tank #2

The applicant is proposing to install a 203,700 gallon Naphtha internal floating roof storage tank.

N-9742-31-0: Slop Storage Tank #1

The applicant is proposing to install a 153,300 gallon Slop internal floating roof storage tank.

N-9742-32-0: Slop Storage Tank #2

The applicant is proposing to install a 300,300 gallon Slop internal floating roof storage tank.

Four Permit-Exempt Renewable Diesel/Sustainable Aviation Fuel Tanks

The applicant is proposing to install four 1,012,200 gallon internal floating roof storage tanks to store the renewable diesel and sustainable aviation fuels that are produced at this site. These units were determined to be categorically exempt from permits. For more details on this determination, please refer to the Rule 2020 discussion in the compliance section of this document.

Disposition of Outstanding ATCs for Facility N-9742

This facility (N-9742) was previously issued ATCs (-1-0 through -19-0) for a cellulosic ethanol plant at this location; however, Aemetis does not intend to install the cellulosic ethanol plant. Furthermore, the ATCs for the cellulosic ethanol plant have expired and are no longer valid.

Stationary Source Determination

Aemetis recently acquired Facility N-8209 from the Riverbank Local Development Authority through a transfer of ownership, which is contiguous to the proposed operation. Facility N-8209 consists of three internal combustion engines powering emergency fire pumps and one internal combustion engine powering an emergency electrical generator. The fire pump engines and emergency generator serve the buildings associated with the former army ammunition plant, including a building currently occupied by tenants that are not associated with Aemetis. Facility N-9742 will have its own dedicated fire pump system and emergency electrical generator that are completely separate from the units at N-8209. Facility N-8209 is contiguous with the proposed facility (N-9742) and the engines from N-8209 will be under the control of the same owner. Facility N-9742 has an SIC code of 2869, which is for the manufacturing of industrial organic chemicals, while Facility N-8209 has an SIC code of 9199, which is a general SIC code that includes government building management services. Since the two facilities do not share a common two-digit SIC code, they are considered separate stationary sources pursuant to Section 3.39 of Rule 2201.

A copy of the Draft ATCs for this project is included in Appendix A.

II. Applicable Rules

Rule 2010	Permits Required (12/17/92)
Rule 2020	Exemptions (12/18/14)
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 4304	Equipment Tuning Procedure for Boilers, Steam Generators, and Process Heaters (10/19/95)
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 4311	Flares (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)
Rule 4455	Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants (6/15/23)
Rule 4623	Storage of Organic Liquids (6/15/23)
Rule 4624	Transfer of Organic Liquid (6/15/23)
Rule 4691	Vegetable Oil Processing Operations (12/17/92)
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) \
Rule 7012	Hexavalent Chromium – Cooling Towers (12/17/92)
CH&SC 41700	Health Risk Assessment
CH&SC 42301.6	School Notice

California Code of Regulations, Title 17 §93115, Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignited Engines
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 5300 Claus Road in Riverbank, 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

This facility will convert animal fats and vegetable oils into renewable diesel and sustainable aviation fuel. A process diagram is included in Appendix B of this evaluation.

Permit Exempt Feedstock Storage and Blending Tanks and Pre-Treatment Operations

The feedstock (vegetable oils and animal fats) will be received and stored in dedicated receiving tanks. Prior to processing, the oils and animal fats will be blended and then pumped to a pretreatment unit to remove any impurities prior to hydro-processing. In the feedstock blending step, feedstock is mixed in a day tank to maintain consistent feed composition to the process. The feed pretreatment system will consist of:

- Drying and crude filtration to remove polyethylene, food waste, metal, and protein from the feedstock
- Ultra-degumming via pH adjustment to remove metal ions and to convert hydrophilic proteins
- Water washing to remove trace impurities such as chlorides and to reduce the load to bleaching
- Double-pass bleaching to remove trace impurities, metals and other compounds

Waste oil from the pretreatment unit will be recovered and processed through the pretreatment unit again. Spent clay generated during pretreatment will be moved to dumpsters and removed from the facility by truck. No emissions to the air are expected from the pre-treatment operations.

The feedstock storage and blending tanks were determined to be not require permits (see Rule 2010 section in the compliance section of this evaluation).

N-9742-20-0: HydroFlex Fuel Production Unit

The HydroFlex Unit (HFU) uses a hydro-treating process to convert feedstock to sustainable aviation fuel and renewable diesel. It includes the following primary processes:

- Hydrogenation – Pretreated feedstock is heated in the presence of hydrogen and catalyst to hydrogenate the oils and remove oxygen and impurities. A small amount of dimethyl sulfide is fed to the reactor to maintain optimum catalyst performance. The hydrocarbons from the reactor will contain unreacted hydrogen, varying length hydrocarbon chains, and other by-products. A series of equipment then separates the hydrogen, hydrogen sulfide, and light end hydrocarbons from the heavier hydrocarbon stream. Hydrogen sulfide is sent to the sour gas treatment unit. Separated hydrogen and light end hydrocarbons are re-used in the process.

- Dewaxing Reactor and Separation – The heavier hydrocarbons contain the final products (Sustainable Aviation Fuel and Renewable Diesel). They are further processed in a dewaxing reactor to improve the cold flow properties of the products. Another series of separation steps first removes hydrogen, hydrogen sulfide, ammonia, light ends, and light naphtha from the hydrocarbon liquid, and then splits the heavy hydrocarbon stream into heavy naphtha, sustainable aviation fuel, and renewable diesel.

- Reuse of Byproducts – The light and heavy naphtha are stabilized prior to storage and reused as a feed to the hydrogen production unit (Reformer) to produce hydrogen. Sour gas, which in this case is gas contaminated with hydrogen sulfide, is a byproduct of the hydrogenation process. A continuous sour off-gas stream is sent to the Sour Gas Treatment unit and then compressed and used as feed to the Reformer. An intermittent purge gas stream will be sent directly to the Hydrogen Unit and purified in a membrane unit.

- Sour Gas Treatment – This unit removes hydrogen sulfide from the off-gas stream generated in the HFU prior to using the gas as a feed for the hydrogen production unit. The sour gas treatment unit consists of fixed-bed vessels arranged in a lead-lag configuration. The solid catalyst in the beds is an iron oxide/hydroxide-based product that selectively targets sulfur compounds, converting them into iron sulfide and elemental sulfur. Sweet off-gas from the reactors is compressed up to the reformer feed gas pressure. The Sour Gas treatment unit has no direct emission sources.

Fugitive volatile organic compounds (VOCs) will be emitted through valves, pumps, compressor seals, and flanges associated with the processes identified above.

Additionally, three natural gas-fired process heaters rated at 19.5 MMBtu/hr, 27.6 MMBtu/hr, and 41.5 MMBtu/hr supply heat to the above HFU processes. Each of the heaters will be equipped with a selective catalytic reduction unit (SCR) to control oxides of nitrogen (NOx) emissions and an oxidation catalyst to control carbon monoxide (CO) and VOC emissions.

<u>N-9742-21-0: Hydrogen Production Unit</u>

The hydrogen production unit (HPU) converts naphtha and off-gas (outputs from the HydroFlex processing unit) into hydrogen. The facility is expected to produce enough naphtha to meet its hydrogen feed requirements, but additional naphtha may be imported and stored in the tank farm, as needed. The HPU consists of the following series of reactors:

- Hydrotreater – Converts organic sulfur compounds in the reformer feed into hydrogen sulfide and converts olefins to saturated hydrocarbons using a cobalt and molybdenum (Co-Mo) catalyst.

- Desulfurization Absorber – Removes the hydrogen sulfide from the process gasses using a zinc-oxide catalyst.

- Pre-Reformer – Converts long chain hydrocarbons into naphtha and methane using a zinc catalyst, preparing the gas stream for the Reformer that processes methane and naphtha

- Reformer – Converts methane and naphtha to CO and hydrogen (H_2) using steam and a zinc catalyst.

- High Temperature Shift Converter – Converts the remaining CO with H_2O to H_2 and carbon dioxide (CO_2) using steam and an iron-chromium catalyst.

- Pressure Swing Adsorber (PSA) – removes impurities to produce pure hydrogen (99+%). The removed off gas is reused as fuel in the process heater that generates steam for the Reformer.

Fugitive VOCs will be emitted through valves, pumps, compressor seals, and flanges associated with the processes identified above.

RTO #1 (Shared with N-9742-24-0) will control VOC emissions from the above processes. Additionally, fugitive VOC emissions will be emitted from valves, flanges, compressor seals, and pumps associated with the above equipment.

The reformer includes one 184 MMBtu/hr process heater. The process heater will primarily be fired on off-gas from the pressure swing adsorber, with supplemental natural gas as needed. The process heater will be equipped with a selective catalytic reduction unit (SCR) to control NOx emissions and an oxidation catalyst to control CO and VOC emissions.

<u>N-9742-22-0: Boiler</u>

A 59 MMBtu/hr natural gas-fired auxiliary boiler will provide additional steam for general plant use.

<u>N-9742-23-0: Material Transfer Operation</u>

The applicant is proposing to install a material transfer operation. The material transfer operation includes the receiving of feedstocks (vegetable oils and animal fats), the offloading of products (sustainable aviation fuel and renewable diesel), and the transfer of Naphtha byproduct. Material will be transferred by loading racks from or to rail cars and trucks. Vapors from this operation will be collected and combusted by a regenerative thermal oxidizer (RTO #2). Fugitive VOCs will be emitted through valves, pumps, compressor seals, and flanges associated with the processes identified above.

<u>N-9742-24-0: Wastewater Treatment Unit</u>

The facility will treat all wastewater on-site to create clean water for process use. All treated water will be re-used without offsite dischargers. Wastewater streams from throughout the facility will be processed in the multi-stage wastewater treatment unit for treatment, recovery, and evaporation. The wastewater unit includes a digester that creates vent digester gas. The digester gas will be routed to a regenerative thermal oxidizer (RTO #1) for control of emissions (RTO #1 is shared with N-9742-21-0). Solids from the wastewater treatment plant will be sent to an offsite landfill for disposal. Vapors from all waste water treatment unit vents are routed through the regenerative thermal oxidizer for the control of VOC emissions. Fugitive VOCs will be emitted by the wastewater treatment unit through valves, pumps, compressor seals, and flanges associated with the processes identified above.

N-9742-25-0: Cooling Tower

Several plant processes will used non-contact cooling water produced by an evaporative cooling tower than includes a cooling water basin, tower, two pumps, chemical treatment, and distribution circuits to deliver and receive back the cooling water. Fresh air is drawn through the tower by a fan, causing evaporation and cooling of the water for distribution back to the plant. The baffles also function as drift eliminators, allowing entrained water droplets to condense and return to the water basin below. After use, the cooled water will recirculate back to the cooling tower for reuse and additional water will be supplied to offset evaporation from the tower.

N-9742-26-0: Emergency Flare

The applicant is proposing to install a 79.17 MMBtu/hr process-gas fired emergency flare. The flare will combust gases vented during an emergency process upset prior to emission to the atmosphere, such as serving as failure of the primary control systems. The flare will have a continuous natural gas pilot light, but will combust process gases only during unplanned venting and not during normal operations of the plant. The flare is necessary to prevent the risk of fire at the plant.

N-9742-27-0: Emergency Firewater Pump

The applicant is proposing to install a 687 BHP Tier 3 certified diesel-fired emergency IC engine powering a firewater pump.

N-9742-28-0: Emergency Electrical Generator

The applicant is proposing to install a 1,341 BHP Tier 4F certified diesel-fired emergency IC engine powering an electrical generator.

N-9742-29-0: Naphtha Storage Tank #1

The applicant is proposing to install a 203,700 gallon Naphtha internal floating roof storage tank. The storage tank will be used to store Naphtha, which is used in the hydrogen production process.

N-9742-30-0: Naphtha Storage Tank #2

The applicant is proposing to install a 203,700 gallon Naphtha internal floating roof storage tank. The storage tank will be used to store Naphtha, which is used in the hydrogen production process.

N-9742-31-0: Slop Storage Tank #1

The applicant is proposing to install a 153,300 gallon Slop internal floating roof storage tank. This tank will contain “Slop”, which is off-spec product created by the HydroFlex unit.

N-9742-32-0: Slop Storage Tank #2

The applicant is proposing to install a 300,300 gallon Slop internal floating roof storage tank. This tank will contain “Slop”, which is off-spec product created by the HydroFlex unit.

Four Permit-Exempt Renewable Diesel/Sustainable Aviation Fuel Tanks

The applicant is proposing to install four 1,012,200 gallon internal floating roof storage tanks to store the renewable diesel and sustainable aviation fuels that are produced at this site. These tanks are categorically exempt from permits. For more details on the exemption determination, please refer to the District Rule 2020 discussion in the compliance section of this document.

V. Equipment Listing

N-9742-20-0: HYDROFLEX FUEL PRODUCTION UNIT CONSISTING OF A HYDROGENATION REACTOR, DEWAXING REACTOR, GAS AND LIQUID SEPARATION EQUIPMENT, FIXED-BED CATALYST VESSELS, SOUR GAS TREATMENT EQUIPMENT, A 19.5 MMBTU/HR NATURAL GAS-FIRED PROCESS HEATER WITH AN OXIDATION CATALYST, ULTRA LOW-NOX BURNER AND SELECTIVE CATALYTIC REDUCTION, A 27.6 MMBTU/HR NATURAL GAS FIRED PROCESS HEATER WITH AN OXIDATION CATALYST, ULTRA LOW-NOX BURNER AND SELECTIVE CATALYTIC REDUCTION, AND A 41.5 MMBTU/HR NATURAL GAS-FIRED PROCESS HEATER WITH AN OXIDATION CATALYST, ULTRA LOW-NOX BURNER AND SELECTIVE CATALYTIC REDUCTION SYSTEM; OR EQUIVALENT

N-9742-21-0: HYDROGEN PRODUCTION UNIT CONSISTING OF A HYDROTREATER, PRE-REFORMER, REFORMER, SHIFT CONVERTERS, AND PRESSURE SWING ADSORBER WITH A 184 MMBTU/HR PROCESS GAS AND NATURAL GAS-FIRED HEATER WITH A CO CATALYST, LOW-NOX BURNER, AND SELECTIVE CATALYTIC REDUCTION SYSTEM; OR EQUIVALENT. HYDROGEN PRODUCTION UNIT GAS IS VENTED TO A SHARED THERMAL OXIDIZER (RTO #1 SHARED WITH N-9742-24-0) WITH A 7.6 MMBTU/HR NATURAL GAS-FIRED BURNER; OR EQUIVALENT

N-9742-22-0: 59 MMBTU/HR PROCESS GAS AND NATURAL GAS-FIRED BOILER WITH A CO CATALYST, LOW-NOX BURNER, AND SELECTIVE CATALYTIC REDUCTION SYSTEM; OR EQUIVALENT

N-9742-23-0 MATERIAL TRANSFER OPERATION (RECEIVING OF FEEDSTOCKS AND OFFLOADING OF PRODUCTS VIA A LOADING RACK TO AND FROM TRUCKS AND RAILCARS) VENTED TO A THERMAL OXIDIZER (RTO #2) WITH A 7.6 MMBTU/HR NATURAL GAS FIRED BURNER

N-9742-24-0: WASTEWATER TREATMENT UNIT VENTED TO A SHARED THERMAL OXIDIZER (RTO #1 SHARED WITH N-9742-21-0) WITH A 7.6 MMBTU/HR NATURAL GAS-FIRED BURNER

N-9742-25-0: 10,200 GALLONS PER MINUTE THREE-CELL COOLING TOWER WITH A DRIFT ELIMINATOR

N-9742-26-0: 79.17 MMBTU/HR PROCESS GAS-FIRED EMERGENCY FLARE

N-9742-27-0: 687 BHP (INTERMITTENT) CLARKE MODEL C18HO TIER 3 CERTIFIED DIESEL-FIRED EMERENCY IC ENGINE POWERING A FIREWATER PUMP

N-9742-28-0: 1341 BHP (INTERMITTENT) CUMMINS MODEL DQFAD TIER 4 FINAL CERTIFIED DIESEL-FIRED EMERGENCY IC ENGINE POWERING AN ELECTRICAL GENERATOR

N-9742-29-0: 203,700 GALLON NAPHTHA STORAGE TANK WITH AN INTERNAL FLOATING ROOF

N-9742-30-0: 203,700 GALLON NAPHTHA STORAGE TANK WITH AN INTERNAL FLOATING ROOF

N-9742-31-0: 153,000 GALLON SLOP STORAGE TANK WITH AN INTERNAL FLOATING ROOF

N-9742-32-0: 300,300 GALLON SLOP STORAGE TANK WITH AN INTERNAL FLOATING ROOF

VI. Emission Control Technology Evaluation

N-9742-20-0: HydroFlex Fuel Production Unit

Emissions from the HFU will consist of combustion emissions from the process heaters and fugitive emissions from valves, pumps, compressor seals, and flanges.

The HFU will include three natural gas-fired heaters (Heater 1, Heater 2, and Heater 3). Criteria air pollutant emissions from the heaters include NOx, CO, VOC, particulates and SOx. NOx formation is due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NOx) and conversion of chemically bound nitrogen in the fuel (fuel NOx). Due to the low fuel nitrogen content of natural gas, nearly all NOx emissions are due to thermal NOx. Each of the three heaters is equipped with ultra-low NOx burners and a selective catalytic reduction system for the control of NOx emissions. Selective catalytic reduction units reduce emissions by reacting NOx with ammonia in the presence of a catalyst, forming nitrogen (N_2) and water. Ammonia emissions will be emitted due to unreacted ammonia (ammonia slip) from the SCR catalyst systems. All three heaters will also be equipped with an oxidation catalyst to reduce CO and VOC emissions. Oxidation catalysts are installed in the exhaust and typically consist of a stainless steel housing containing a catalyzed substrate. The catalyst reduces emissions through chemical reactions that convert carbon monoxide, hydrocarbons, and aldehydes into carbon dioxide and water. The proposed oxidation catalysts are capable of reducing CO emissions to an exhaust concentration at or below 25 ppmv @ 3% O_2 and reducing VOC emissions by at least 90%.

Fugitive VOC emissions will be emitted through valves, flanges, compressor seals, and pumps.

N-9742-21-0: Hydrogen Production Unit (HPU)

Emissions from the HPU will include combustion emissions from the 184 MMBtu/hr process heater, process VOC emissions and combustion emissions from processes served by regenerative thermal oxidizer #1, and fugitive VOC emissions.

The HPU includes a 184 MMBtu/hr process heater fired on process gas and natural gas. Criteria air pollutant emissions from the heaters include NOx, CO, VOC, particulates and SOx. NOx formation is due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NOx) and conversion of chemically bound nitrogen in the fuel (fuel NOx). Due to the low fuel nitrogen content of natural gas, nearly all NOx emissions are due to thermal NOx. The process heater is equipped with an ultra-low NOx burner and a selective catalytic reduction system for the control of NOx emissions. Selective catalytic reduction units reduce emissions by reacting NOx with ammonia in the presence of a catalyst, forming nitrogen (N_2) and water. Ammonia emissions will be emitted due to unreacted ammonia (ammonia slip) from the SCR catalyst system. The heater will also be equipped with an oxidation catalyst to reduce CO and VOC emissions. Oxidation catalysts are installed in the exhaust and typically consist of a stainless steel housing containing a catalyzed substrate. The catalyst reduces emissions through chemical reactions that convert carbon monoxide, hydrocarbons, and aldehydes into carbon dioxide and water. The proposed oxidation catalysts are capable of reducing CO emissions to an exhaust concentration at or below 25 ppmv @ 3% O_2 and reducing VOC emissions by at least 90%.

Additionally, VOC emissions HPU process vents will be routed through regenerative thermal oxidizer #1 to reduce VOC emissions. The proposed regenerative thermal oxidizer will capture and control 99% of VOC emissions from the waste gas streams. Regenerative thermal oxidizer #1 will also control emissions from the wastewater treatment unit process vents (N-9742-24-0).

Finally, fugitive VOC emissions will be emitted through valves, flanges, compressor seals, and pumps.

N-9742-22-0: Boiler

Criteria air pollutant emissions from the boiler include NOx, CO, VOC, particulates, and SOx. NOx formation is due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NOx) and conversion of chemically bound nitrogen in the fuel (fuel NOx). Due to the low fuel nitrogen content of natural gas, nearly all NOx emissions are due to thermal NOx. The boiler will have a low-NOx burner and a selective catalytic reduction system for the control of NOx emissions. Ammonia emissions will be emitted due to unreacted ammonia (ammonia slip) from the SCR catalyst system. The boiler will also be equipped with a CO catalyst capable of reducing CO emissions to an exhaust concentration at or below 25 ppmv CO @ 3% O_2 and control VOC emissions by at least 90%.

N-9742-23-0: Material Transfer Operation

VOC emissions will result from the displacement of vapors during the transfer of material from, or to, railcars and trucks. The displaced vapors will be captured by a vapor control system and routed to a regenerative thermal oxidizer that will reduce VOCs by at least 99% by weight.

VOCs will also be emitted during the disconnection of product lines after the transfer of materials. These emissions will be limited to 10 mL of spillage per disconnect (10 mL = 0.00264 gal) and will be minimized through the use of dry break couplers. Dry break couplers have an automatic mechanism to seal off both ends of a line when a hose is disconnected, greatly reducing emissions from leaks during the disconnection of material transfer lines. Additionally, fugitive VOC emissions will be emitted through valves, flanges, compressor seals, and pumps.

N-9742-24-0: Wastewater Treatment Unit

The wastewater treatment unit will be vented to a vapor recovery system that will route vapors to a shared regenerative thermal oxidizer (RTO #1 shared with N-9742-21-0) and will reduce VOC emissions by at least 99% by weight. Additionally, fugitive VOC emissions will be emitted through valves, flanges, compressor seals, and pumps.

N-9742-25-0: Cooling Tower

The cooling tower will be an induced draft design equipped with drift eliminators to reduce particulate emissions. The cooling tower has an expected drift rate factor of 0.0005%.

N-9742-26-0: Emergency Flare

The emergency flare will be equipped with a low-NOx burner for the reduction of NOx emissions.

N-9742-27-0: Emergency Firewater Pump

The applicant has proposed to install a Tier 3 certified diesel-fired IC engine that is fired on very low-sulfur diesel fuel.

The proposed engine meets the latest Tier Certification requirements for emergency standby engines; therefore, the engine meets the latest ARB/EPA emissions standards for diesel particulate matter, hydrocarbons, nitrogen oxides, and carbon monoxide (see Appendix C for a copy of the engine data sheet.

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

N-9742-28-0: Emergency Electrical Generator

The applicant has proposed to install a Tier 4 final certified diesel-fired IC engine that is fired on very low-sulfur diesel fuel.

The proposed engine meets the latest Tier Certification requirements for emergency standby engines; therefore, the engine meets the latest ARB/EPA emissions standards for diesel particulate matter, hydrocarbons, nitrogen oxides, and carbon monoxide.

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

N-9742-29-0: Naphtha Storage Tank #1

The use of an internal floating roof storage tank minimizes working loss emissions since there is little to no space where vapors may be displaced while filling or unloading material from the tank. Standing losses are minimized by the use of a primary and secondary seal system that prevents the loss of organic liquids around the rim of the tank where the tank sides meet up with the floating roof.

N-9742-30-0: Naphtha Storage Tank #2

The use of an internal floating roof storage tank minimizes working loss emissions since there is little to no space where vapors may be displaced while filling or unloading material from the tank. Standing losses are minimized by the use of a primary and secondary seal system that prevents the loss of organic liquids around the rim of the tank where the tank sides meet up with the floating roof.

N-9742-31-0: Slop Storage Tank #1

The use of an internal floating roof storage tank minimizes working loss emissions since there is little to no space where vapors may be displaced while filling or unloading material from the tank. Standing losses are minimized by the use of a primary and secondary seal system that prevents the loss of organic liquids around the rim of the tank where the tank sides meet up with the floating roof.

N-9742-32-0: Slop Storage Tank #2

The use of an internal floating roof storage tank minimizes working loss emissions since there is little to no space where vapors may be displaced while filling or unloading material from the tank. Standing losses are minimized by the use of a primary and secondary seal system that prevents the loss of organic liquids around the rim of the tank where the tank sides meet up with the floating roof.

VII. General Calculations

A. Assumptions

N-9742-20-0: HydroFlex Fuel Production Unit

Process Heaters:

- Natural Gas Higher Heating Value: 1000 Btu/scf
- F-Factor for Natural Gas: 8,578 dscf/MMBtu
- The oxidation catalyst will control VOCs by at least 90% by weight.
- Each process heater may operate up to 24 hr/day, 365 days/year.
- For each heater, the maximum startup time per event is 8 hours, while the maximum shutdown time per event is 2 hours. The maximum combined startup/shutdown time in any one day is 8 hours per day and 200 hours/year for each heater.

Fugitive Emission Sources:

- Fugitive emissions are assessed to components handling fluid streams that contain more than 10% by weight VOC and that are not under vacuum.
- This unit will include 366 valves in gas service, 474 valves in light liquid service, 9 pumps in light liquid service, 2 compressor seals in gas service, and 2,370 flanges.
- Conversion: 2.205 lb = 1 kg

N-9742-21-0: Hydrogen Production Unit

Process Heater:

- F-Factor for heater fuel gas (natural gas/process gas): 8,224 dscf/MMBtu
- The 184 MMBtu/hr process heater may operate up to 24 hr/day, 365 days/year.
- The maximum startup time per event is 12 hours, while the maximum shutdown time per event is 2 hours. A cold startup and shutdown are not expected to occur on the same day. The maximum combined startup/shutdown time in any one day is 12 hours.
- Annual Startup and shutdown of the process heater is limited to 200 hours combined.
- The maximum fuel sulfur content is 1.75 grains/100 dscf.
- The oxidation catalyst will control VOCs by at least 90% by weight.

RTO #1:

- Emissions from the regenerative thermal oxidizer are based upon both natural gas combustion from a 7.6 MMBtu/hr burner and the combustion of process gas.
- Maximum natural gas usage for RTO #1 is 182 MMBtu/day, 66,576 MMBtu/year.
- Maximum process gas influent heat input to RTO #1 is proposed as follows: 33 MMBtu/hr and 274 MMBtu/year. The daily maximum process gas influent heat input will conservatively be set to the annual limit of 274 MMBtu/year.
- The F-Factor for natural gas is 8,578 dscf/MMBtu.

- The F-Factor for the process gas is 8,224 dscf/MMBtu.
- The maximum process gas flow rate into the thermal oxidizer is 14,929 scfm.
- The control efficiency of regenerative thermal oxidizer #1 is 99% by weight.
- The maximum process gas sulfur content at the oxidizer inlet is 1.75 gr/100 scf.

Fugitive Emission Sources:

- Fugitive emissions are assessed to components handling flued streams that contain more than 10% by weight VOC and that are not under vacuum.
- This unit will include 227 valves in gas service, 75 valves in light liquid service, 2 pumps in light liquid service, 2 compressor seals in gas service, and 1,109 flanges.
- Conversion: 2.205 lb = 1 kg

N-9742-22-0: Boiler

- Natural Gas Higher Heating Value: 1000 Btu/scf
- F-Factor for Natural Gas: 8578 dscf/MMBtu
- Maximum Total heat Input: 59 MMBtu/hr, 1,416 MMBtu/day, 516,840 MMBtu/year
- Combined Daily Startup and Shutdown of Boiler is limited to 8 hours.
- The maximum startup time per event is 8 hours, while the maximum shutdown time per event is 2 hours. The maximum combined startup/shutdown time in any one day is 8 hours per day and 200 hours/year.
- The oxidation catalyst will control VOCs by at least 90% by weight

N-9742-23-0: Material Transfer Operation

RTO #2:

- Emissions from the regenerative thermal oxidizer are based upon both natural gas combustion from a 7.6 MMBtu/hr burner and the combustion of process gas.
- Maximum natural gas usage for RTO # 2 is 182 MMBtu/day, 66,576 MMBtu/year.
- Maximum process gas influent heat input to RTO #2 will be limited to 792 MMBtu/day and 1,122 MMBtu/year.
- The F-Factor for natural gas is 8,578 dscf/MMBtu.
- The F-Factor for the process gas is 8,224 dscf/MMBtu.
- The maximum process gas flow rate into the regenerative thermal oxidizer is 14,929 scfm.
- The control efficiency of regenerative thermal oxidizer #1 is 99% by weight
- The maximum process gas sulfur content at the thermal oxidizer inlet is 1.75 gr/100 scf

Product Line Disconnects:

- For loading and unloading, a spillage rate of 10 mL per disconnect is assumed (10 mL = 0.00264 gal).
- VOC emissions are calculated based on truck loading and unloading disconnects. 100% truck disconnects will result in more disconnects than a mixture of truck/railcar disconnects; therefore, assuming all truck disconnects is the most conservative assumption.
- Vapor return lines are not a source of liquid spillage.
- Maximum quantity of feedstock transfer disconnects: 120/day and 20,000/year.
- Maximum quantity of product transfer disconnects (SAF and RD combined): 120/day and 20,000/year.
- Maximum potential number of naphtha byproduct transfer disconnects: 6/day and 757/year.

Fugitive Emission Sources:

- Fugitive emissions are assessed to components handling flued streams that contain more than 10% by weight VOC and that are not under vacuum.
- This unit will include 8 valves in gas service, 11 valves in light liquid service, 0 pumps in light liquid service, 0 compressor seals in gas service, and 154 flanges.
- Conversion: 2.205 lb = 1 kg

N-9742-24-0: Wastewater Treatment Unit

Process Vent emissions served by RTO #1:

- Process vent emissions from the wastewater treatment unit will be controlled by regenerative thermal oxidizer #1 (Shared with N-9742-21-0).
- Emissions from the process served by RTO #1 are already accounted for in the calculations for unit N-9742-21-0.

Fugitive Emission Sources:

- Fugitive emissions are assessed to components handling flued streams that contain more than 10% by weight VOC and that are not under vacuum.
- This unit will include 12 valves in gas service, 20 valves in light liquid service, 0 pumps in light liquid service, 0 compressor seals in gas service, and 217 flanges.
- Conversion: 2.205 lb = 1 kg

N-9742-25-0: Cooling Tower

- Cooling Tower Recirculation Rate: 10,200 gallons/minute
- Cooling Tower Drift Loss: 0.0005% by weight
- Cooling Tower total dissolved solids will not exceed 597.5 ppmw. (per Applicant)
- Density of cooling tower water is 8.23 lb/gal. (per Applicant)

N-9742-26-0: Emergency Flare

- The emergency flare pilot light operates continuously on natural gas fuel.
- The flare will only combust process gasses during periods of plant upsets.
- Maximum flared heat input will be limited to 1,900 MMBtu/day and 7,400 MMBtu/year. This heat input includes the pilot fuel usage.
- Sulfur concentration of flared gas: 22.17 gr/100 scf
- Flared gas heating value: 2,089 Btu/scf

N-9742-27-0: Emergency Firewater Pump

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

N-9742-28-0: Emergency Electrical Generator

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

N-9742-29-0: Naphtha Storage Tank #1

- Fugitive VOC emissions are assessed to components handling fluid streams that contain more than 10% by weight VOC and that are not under vacuum.
- Maximum annual throughput: 212,795 bbl/year

N-9742-30-0: Naphtha Storage Tank #2

- Fugitive VOC emissions are assessed to components handling fluid streams that contain more than 10% by weight VOC and that are not under vacuum.
- Maximum annual throughput: 212,795 bbl/year

N-9742-31-0: Slop Storage Tank #1

- Fugitive VOC emissions are assessed to components handling fluid streams that contain more than 10% by weight VOC and that are not under vacuum.
- Maximum annual throughput: 7,300 bbl/year

N-9742-32-0: Slop Storage Tank #2

- Fugitive VOC emissions are assessed to components handling fluid streams that contain more than 10% by weight VOC and that are not under vacuum.
- Maximum annual throughput: 14,300 bbl/year

B. Emission Factors

N-9742-20-0: HydroFlex Fuel Production Unit

The applicant is proposing the following emission factors for the process heaters:

Emission Factors – Heater #1 (19.5 MMBtu/hr)			
Pollutant	**Emission Factor (ppmv @ 3% O_2)**	**Emission Factor (lb/MMBtu)**	**Source**
NO_X (Steady State)	5	0.0061[1]	Manufacturer
NO_X (Start-up/Shutdown)	50	0.061[1]	Low-NOx Burner
SO_X	N/A	0.00285	District Policy APR 1720
PM_{10}	N/A	0.003	District Practice
CO	25	0.018[1]	Oxidation Catalyst Manufacturer
VOC	N/A	0.00055	AP-42 Table 1.4.2 uncontrolled factor of 0.0055 lb/MMBtu with 90% control applied for the proposed oxidation catalyst
NH_3	5	0.0022[1]	Applicant

[1] Conversion ppm to lb/MMBtu was made using the following formula:

$$EF\left(\frac{lb}{MMbtu}\right) = \frac{EF(ppmv) \times 8578\,\frac{dscf}{MMBtu} \times MW\,\frac{lb}{lb-mol} \times \frac{20.95}{17.95}}{379.5\,\frac{scf}{lb-mol} \times 10^6}$$

Emission Factors – Heaters #2 (27.6 MMBtu/hr) and #3 (41.5 MMBtu/hr)			
Pollutant	**Emission Factor (ppmv @ 3% O_2)**	**Emission Factor (lb/MMBtu)**	**Source**
NO_X (Steady State)	2.5	0.003[1]	Manufacturer
NO_X (Start-up/Shutdown)	50	0.061[1]	Low-NOx Burner
SO_X	N/A	0.00285	District Policy APR 1720
PM_{10}	N/A	0.003	District Practice
CO	25	0.018[1]	Oxidation Catalyst Manufacturer
VOC	N/A	0.00055	AP-42 Table 1.4.2 uncontrolled factor of 0.0055 lb/MMBtu with 90% control applied for the proposed oxidation catalyst
NH_3	5	0.0022[1]	Applicant

The following emission factors will be used for fugitive components associated with the HydroFlex unit. For a copy of the USA EPA Protocol for Equipment Leak Emission Table 2-10 formulas, please refer to Appendix G of this document.

Emission Factors: Fugitive Components			
Component Type	**Screening Value (ppmv)**	**Leak Rate (kg/hr/source)**	**Source**
Valves (gas)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Valves (light liquid)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Pumps (light liquid)	500	2.23E-03	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Compressor Seals (gas)	500	5.29E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Flanges (any)	100	1.17E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula

N-9742-21-0: Hydrogen Production Unit

Emission Factors: Process Heater (184 MMBtu/hr)			
Pollutant	**Emission Factor (ppmv @ 3% O_2)**	**Emission Factor (lb/MMBtu)**	**Source**
NO_X (Steady State)	2.5	0.0029[2]	Manufacturer
NO_X (Start-up/Shutdown)	N/A	0.14	AP-42 Table 1.4-1
SO_X	N/A	0.0127	See Equation Below
PM_{10}	N/A	0.0038	Applicant Proposal
CO	25	0.018[2]	Oxidation Catalyst manufacturer
VOC	N/A	0.000275	Proposed by applicant, includes 90% control from oxidation catalyst
NH_3	5	0.002[2]	Applicant

SOx EF = $\frac{1.75\ grains{-}S}{100\ dscf} \times \frac{lb{-}S}{7000\ grains} \times \frac{dscf}{395\ Btu} \times \frac{10^6 Btu}{MMBtu} \times \frac{2\ lb{-}SO2}{lb{-}S} = \frac{0.0127\ lb}{MMBtu}$

[2] Conversion ppm to lb/MMBtu was made using the following formula:

$$EF\left(\frac{lb}{MMbtu}\right) = \frac{EF(ppmv) \times 8228\ \frac{dscf}{MMBtu} \times\ MW \frac{lb}{lb-mol} \times \frac{20.95}{17.95}}{379.5 \frac{scf}{lb-mol} \times 10^6}$$

Emission Factors: Regenerative Thermal Oxidizer #1			
Pollutant	Emission Factor (ppmv @ 3% O_2)	Emission Factor (lb/MMBtu)	Source
NO_X (Natural Gas)	5	0.0061[3]	Manufacturer's Guarantee
NO_X (Process Gas)	5	0.0058[4]	Manufacturer's Guarantee
SO_X (Natural Gas)	N/A	0.00285	District Policy APR 1720
SO_X (Process Gas)	N/A	0.021	See Equation Below
PM_{10}	N/A	0.0076	AP-42 Table 1.4-2
CO (Natural Gas)	5	0.0037[3]	Manufacturer's Guarantee
CO (Process Gas)	5	0.0035[4]	Manufacturer's Guarantee
VOC (Natural Gas)	N/A	0.0055	AP-42 Table 1.4-2
VOC (Process Gas)		0.0106	Proposed by Applicant

$$\text{SOx EF} = \frac{1.75\ grains-S}{100\ dscf} \times \frac{lb-S}{7000\ grains} \times \frac{dscf}{238\ Btu} \times \frac{10^6 Btu}{MMBtu} \times \frac{2\ lb-SO2}{lb-S} = \frac{0.021\ lb}{MMBtu}$$

[3] Conversion ppm to lb/MMBtu was made using the following formula:

$$EF\left(\frac{lb}{MMbtu}\right) = \frac{EF(ppmv) \times 8578\ \frac{dscf}{MMBtu} \times\ MW \frac{lb}{lb-mol} \times \frac{20.95}{17.95}}{379.5 \frac{scf}{lb-mol} \times 10^6}$$

[4] Conversion ppm to lb/MMBtu was made using the following formula:

$$EF\left(\frac{lb}{MMbtu}\right) = \frac{EF(ppmv) \times 8228\ \frac{dscf}{MMBtu} \times\ MW \frac{lb}{lb-mol} \times \frac{20.95}{17.95}}{379.5 \frac{scf}{lb-mol} \times 10^6}$$

The following emission factors will be used for fugitive components associated with the hydrogen production unit.

Emission Factors: Fugitive Components (HPU)			
Component Type	**Screening Value (ppmv)**	**Leak Rate (kg/hr/source)**	**Source**
Valves (gas)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Valves (light liquid)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Pumps (light liquid)	500	2.23E-03	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Compressor Seals (gas)	500	5.29E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Flanges (any)	100	1.17E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula

<u>N-9742-22-0: Boiler</u>

Emission Factors: 59 MMBtu/hr Auxiliary Boiler			
Pollutant	**Emission Factor (ppmv @ 3% O_2)**	**Emission Factor (lb/MMBtu)**	**Source**
NO_X (Steady State)	2.5	0.003[5]	Manufacturer's Guarantee
NO_X (Start-up/Shutdown)	50	0.061[5]	Manufacturer's Guarantee
SO_X	N/A	0.00285	See Equation Below
PM_{10}	N/A	0.003	Applicant Proposal
CO	25	0.018[5]	Manufacturer's Guarantee
VOC	N/A	0.00055	AP-42 Table 1.4.2 uncontrolled factor of 0.0055 lb/MMBtu with 90% control applied for the proposed oxidation catalyst
NH_3	10	0.0045[5]	Applicant

[5] Conversion ppm to lb/MMBtu was made using the following formula:

$$EF\left(\frac{lb}{MMbtu}\right) = \frac{EF(ppmv) \times 8578\,\frac{dscf}{MMBtu} \times MW\,\frac{lb}{lb-mol} \times \frac{20.95}{17.95}}{379.5\,\frac{scf}{lb-mol} \times 10^6}$$

N-9742-23-0: Material Transfer Operation

Emission Factors: Regenerative Thermal Oxidizer #2			
Pollutant	**Emission Factor (ppmv @ 3% O_2)**	**Emission Factor (lb/MMBtu)**	**Source**
NO_X (Natural Gas)	5	0.0061[6]	Manufacturer's Guarantee
NO_X (Process Gas)	5	0.0058[7]	Manufacturer's Guarantee
SO_X (Natural Gas)	N/A	0.00285	District Policy APR 1720
SO_X (Process Gas)	N/A	0.0106	See Equation Below
PM_{10}	N/A	0.0076	AP-42 Table 1.4-2
CO (Natural Gas)	5	0.0037[6]	Manufacturer's Guarantee
CO (Process Gas)	5	0.0035[7]	Manufacturer's Guarantee
VOC (Natural Gas)	N/A	0.0055	AP-42 Table 1.4-2
VOC (Process Gas)	N/A	0.0106	Proposed by Applicant

SOx EF = $\frac{1.75\ grains-S}{100\ dscf} \times \frac{lb-S}{7000\ grains} \times \frac{dscf}{238\ Btu} \times \frac{10^6 Btu}{MMBtu} \times \frac{2\ lb-SO2}{lb-S} = \frac{0.021\ lb}{MMBtu}$

Emissions from the spillage of materials during the disconnection of product lines are based upon a spillage rate of 10 mL (0.00264 gal) per disconnect during loading and unloading, and assuming 100% of the material spilled is VOCs. The spill rate and material density are used to calculate an emission factor per disconnect for each product, using the formula below:

$$VOC\ EF\left(\frac{lb}{disconnect}\right) = Spill\ Rate\left(\frac{mL}{disconnect}\right) \times \left(\frac{gal}{3{,}785.4\ mL}\right) \times Material\ Density\ \left(\frac{lb}{gal}\right)$$

[6] Conversion ppm to lb/MMBtu was made using the following formula:

$$EF\left(\frac{lb}{MMbtu}\right) = \frac{EF(ppmv) \times 8578\ \frac{dscf}{MMBtu} \times\ MW\frac{lb}{lb-mol} \times \frac{20.95}{17.95}}{379.5\frac{scf}{lb-mol} \times 10^6}$$

[7] Conversion ppm to lb/MMBtu was made using the following formula:

$$EF\left(\frac{lb}{MMbtu}\right) = \frac{EF(ppmv) \times 8578\ \frac{dscf}{MMBtu} \times\ MW\frac{lb}{lb-mol} \times \frac{20.95}{17.95}}{379.5\frac{scf}{lb-mol} \times 10^6}$$

The following table shows the VOC emission factor for spillage during disconnects for different materials transferred at the facility, using the formula from the previous page and a leak rate of 10 mL per disconnect:

Emission Factors: Regenerative Thermal Oxidizer #2		
Material	**Material Density (lb/gal)**	**EF (lb/disconnect)**
Feedstock	7.49	0.021
Renewable Diesel	6.31	0.017
Sustainable Aviation Fuel	5.90	0.016
Naphtha Byproduct	6.55	0.017

Emission Factors: Fugitive Components			
Component Type	**Screening Value (ppmv)**	**Leak Rate (kg/hr/source)**	**Source**
Valves (gas)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Valves (light liquid)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Pumps (light liquid)	500	2.23E-03	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Compressor Seals (gas)	500	5.29E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Flanges (any)	100	1.17E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula

N-9742-24-0: Wastewater Treatment Unit (WTU)

RTO #1 emissions have already been accounted for under permit unit N-9742-21-0; therefore, the emission factors for that unit will not be included here.

The following emission factors will be used for fugitive components associated with the wastewater treatment unit:

Emission Factors: Fugitive Components (WTU)			
Component Type	**Screening Value (ppmv)**	**Leak Rate (kg/hr/source)**	**Source**
Valves (gas)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Valves (light liquid)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Pumps (light liquid)	500	2.23E-03	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Compressor Seals (gas)	500	5.29E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Flanges (any)	100	1.17E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula

N-9742-25-0: Cooling Tower

The cooling tower emissions are based on the maximum total dissolved solids (TDS) in the makeup water supply, the maximum design water circulation rate, and a drift loss of 0.0005%. Assuming all TDS is PM_{10}:

$$Drift\ Rate\left(\frac{lb-PM_{10}}{gal}\right) = Water\ Density\left(\frac{lb-water}{gal}\right)\times\frac{TDS\ (ppmv)}{10^6}\times\frac{\%\ Drift\ Loss}{100}$$

$$Drift\ Rate\left(\frac{lb-PM_{10}}{gal}\right) = 8.23\left(\frac{lb-water}{gal}\right)\times\frac{597.5\ (ppmv)}{10^6}\times\frac{0.0005}{100} = 2.46\ E-08$$

N-9742-26-0: Emergency Flare

Emission Factors – Emergency Flare		
Pollutant	**Emission Factor (lb/MMBtu)**	**Source**
NO_X	0.068	AP-42 Table 13.5-1
SO_X	0.030	See Calculation Below
PM_{10}	0.05	Manufacturer's Design Specifications
CO	0.37	Manufacturer's Design Specifications
VOC	0.14	AP-42 Table 13.5-1

SOx EF = $\frac{22.17\ grains-S}{100\ dscf}\times\frac{lb-S}{7000\ grains}\times\frac{dscf}{2089\ Btu}\times\frac{10^6 Btu}{MMBtu}\times\frac{2\ lb-SO2}{lb-S} = \frac{0.030\ lb}{MMBtu}$

N-9742-27-0: Emergency Firewater Pump

Emission Factors – Emergency Firewater Pump		
Pollutant	Emission Factor (g/bhp-hr)	Source
NO_X	2.65	Manufacturer
SO_X	0.0051	See Calculation Below
PM_{10}	0.087	Manufacturer
CO	0.92	Manufacturer
VOC	0.06	Manufacturer

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

N-9742-28-0: Emergency Electrical Generator

Emission Factors – Emergency Electrical Generator		
Pollutant	Emission Factor (g/bhp-hr)	Source
NO_X	0.5	Manufacturer
SO_X	0.0051	See Calculation Below
PM_{10}	0.022	Manufacturer
CO	2.0	Manufacturer
VOC	0.14	Manufacturer

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

N-9742-29-0: Naphtha Storage Tank #1

Tank emissions are calculated using storage tank physical parameters, organic liquid throughputs, and stored material properties as inputs to AP-42 Chapter 7 Equations. Emissions were determined using the BREEZE TankESP program.

Fugitive emissions from components associated with the tank are calculated using the following emission factors:

Emission Factors: Fugitive Components (Tank)			
Component Type	**Screening Value (ppmv)**	**Leak Rate (kg/hr/source)**	**Source**
Valves (gas)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Valves (light liquid)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Pumps (light liquid)	500	2.23E-03	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Compressor Seals (gas)	500	5.29E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Flanges (any)	100	1.17E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula

N-9742-30-0: Naphtha Storage Tank #2

Tank emissions are calculated using storage tank physical parameters, organic liquid throughputs, and stored material properties as inputs to AP-42 Chapter 7 Equations. Emissions were determined using the BREEZE TankESP program.

Fugitive emissions from components associated with the tank are calculated using the following emission factors:

Emission Factors: Fugitive Components (Tank)			
Component Type	**Screening Value (ppmv)**	**Leak Rate (kg/hr/source)**	**Source**
Valves (gas)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Valves (light liquid)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Pumps (light liquid)	500	2.23E-03	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Compressor Seals (gas)	500	5.29E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Flanges (any)	100	1.17E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula

N-9742-31-0: Slop Storage Tank #1

Tank emissions are calculated using storage tank physical parameters, organic liquid throughputs, and stored material properties as inputs to AP-42 Chapter 7 Equations. Emissions were determined using the BREEZE TankESP program.

Fugitive emissions from components associated with the tank are calculated using the following emission factors:

Emission Factors: Fugitive Components (Tank)			
Component Type	**Screening Value (ppmv)**	**Leak Rate (kg/hr/source)**	**Source**
Valves (gas)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Valves (light liquid)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Pumps (light liquid)	500	2.23E-03	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Compressor Seals (gas)	500	5.29E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Flanges (any)	100	1.17E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula

N-9742-32-0: Slop Storage Tank #2

Tank emissions are calculated using storage tank physical parameters, organic liquid throughputs, and stored material properties as inputs to AP-42 Chapter 7 Equations. Emissions were determined using the BREEZE TankESP program.

Fugitive emissions from components associated with the tank are calculated using the following emission factors:

Emission Factors: Fugitive Components (Tank)			
Component Type	**Screening Value (ppmv)**	**Leak Rate (kg/hr/source)**	**Source**
Valves (gas)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Valves (light liquid)	100	7.11E-05	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Pumps (light liquid)	500	2.23E-03	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Compressor Seals (gas)	500	5.29E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula
Flanges (any)	100	1.17E-04	US EPA Protocol for Equipment Leak Emissions Table 2-10 formula

C. Calculations

1. Pre-Project Potential to Emit (PE1)

All of the emission units in this project are new; therefore, PE1 is equal to zero.

2. Post-Project Potential to Emit (PE2)

<u>N-9742-20-0: HydroFlex Fuel Production Unit</u>

Emissions from each of the process heaters will be calculated using the following formulas:

Daily Emissions:

$PE2_{NOx}$ = 16 hr/day x Heat Input (MMBtu/hr) x $EF_{Steady\ State}$ (lb/MMBtu) + 8 hr/day x Heat Input x (MMBtu/hr) x $EF_{Startup/shutdown}$

`$PE2_{All\ other\ pollutants}$ = 24 hr/day x Heat Input (MMBtu/hr) x EF (lb/MMBtu)

Annual Emissions:

$PE2_{NOx}$ = 8,560 hr/year x Heat Input (MMBtu/hr) x $EF_{Steady\ State}$ (lb/MMBtu) + 200 hr/yr x Heat Input x (MMBtu/hr) x $EF_{Startup/shutdown}$

`$PE2_{All\ other\ pollutants}$ = 8,760 hr/yr x Heat Input (MMBtu/hr) x EF (lb/MMBtu)

Emissions – Heater #1 (19.5 MMBtu/hr)			
Pollutant	**Emission Factor (lb/MMBtu)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	0.0061 (steady state) 0.061 (startup/shutdown)	11.4	1,256
SO_X	0.00285	1.3	487
PM_{10}	0.003	1.4	512
CO	0.018	8.4	3,075
VOC	0.00055	0.3	94
NH_3	0.0022	1.0	376

Emissions – Heater #2 (27.6 MMBtu/hr)			
Pollutant	**Emission Factor (lb/MMBtu)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	0.003 (steady state) 0.061 (startup/shutdown)	14.8	1,045
SO_X	0.00285	1.9	689
PM_{10}	0.003	2.0	725
CO	0.018	11.9	4,352
VOC	0.00055	0.4	133
NH_3	0.0022	1.5	532

Emissions – Heater #3 (41.5 MMBtu/hr)			
Pollutant	**Emission Factor (lb/MMBtu)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	0.003 (steady state) 0.061 (startup/shutdown)	22.2	1,572
SO_X	0.00285	2.8	1,036
PM_{10}	0.003	3.0	1,091
CO	0.018	17.9	6,544
VOC	0.00055	0.5	200
NH_3	0.0022	2.2	800

Emissions from fugitive components will be calculated as follows:

$PE2_{Daily}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 24 hr/day
$PE2_{Annual}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 8760 hr/yr

Emissions: Fugitive Components				
Pollutant	**Component Count**	**Leak Rate (kg/hr/source)**	**PE2 (lb/day)**	**PE2 (lb/year)**
Valves (gas)	366	7.11E-05	1.4	503
Valves (light liquid)	474	7.11E-05	1.8	651
Pumps (light liquid)	9	2.23E-03	1.1	388
Compressor Seals (gas)	2	5.29E-04	0.1	20
Flanges (any)	2,370	1.17E-04	14.7	5,356

Total annual emissions from this permit unit are shown below:

Annual Emissions: Permit Unit N-9742-20					
Pollutant	**Heater #1 (lb/year)**	**Heater #2 (lb/year)**	**Heater #3 (lb/year)**	**Fugitives (lb/year)**	**PE2 (lb/year)**
NO_X	1,256	1,045	1,572	0	3,873
SO_X	487	689	1,036	0	2,212
PM_{10}	512	725	1,091	0	2,328
CO	3,075	4,352	6,544	0	13,971
VOC	94	133	200	6,918	7,345
NH_3	376	532	800	0	1,708

N-9742-21-0: Hydrogen Production Unit

Emissions from the process heater will be calculated using the following formulas:

Daily Emissions:

$PE2_{NOx}$ = 12 hr/day x Heat Input (MMBtu/hr) x $EF_{Steady\ State}$ (lb/MMBtu) + 12 hr/day x Heat Input x (MMBtu/hr) x $EF_{Startup/shutdown}$

`$PE2_{All\ other\ pollutants}$ = 24 hr/day x Heat Input (MMBtu/hr) x EF (lb/MMBtu)

Annual Emissions:

$PE2_{NOx}$ = 8,560 hr/year x Heat Input (MMBtu/hr) x $EF_{Steady\ State}$ (lb/MMBtu) + 200 hr/yr x Heat Input x (MMBtu/hr) x $EF_{Startup/shutdown}$

`$PE2_{All\ other\ pollutants}$ = 8,760 hr/yr x Heat Input (MMBtu/hr) x EF (lb/MMBtu)

Emissions: Process Heater (184 MMBtu/hr)			
Pollutant	**Emission Factor (lb/MMBtu)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	0.0029 (steady state) 0.14 (startup/shutdown)	315.5	9,720
SO_X	0.021	56.1	20,470
PM_{10}	0.0038	16.8	6,125
CO	0.018	79.5	29,013
VOC	0.000275	1.2	443
NH_3	0.002	8.8	3,224

Emissions from the regenerative thermal oxidizer are calculated using the following formulas:

Daily Emissions:

PE2 = 7.6 MMBtu/hr x 24 hr/day x $EF_{\text{natural gas}}$ + 274 MMBtu/day x $EF_{\text{Process Gas}}$

Annual Emissions:

PE2 = 7.6 MMBtu/hr x 8,760 hr/year x $EF_{\text{natural gas}}$ + 274 MMBtu/year x $EF_{\text{Process Gas}}$

Emissions: Regenerative Thermal Oxidizer #1			
Pollutant	**Emission Factor (lb/MMBtu)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	0.0061 (natural gas) 0.0058 (process gas)	2.7	408
SO_X	0.00285 (natural gas) 0.021 (process gas)	6.2	195
PM_{10}	0.0076 (natural gas and process gas)	3.4	508
CO	0.0037 (natural gas) 0.0035 (process gas)	1.6	247
VOC	0.0055 (natural gas) 0.0106 (process gas)	3.9	369

Emissions from fugitive components will be calculated as follows:

$PE2_{\text{Daily}}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 24 hr/day
$PE2_{\text{Annual}}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 8760 hr/yr

Emissions: Fugitive Components				
Pollutant	**Component Count**	**Leak Rate (kg/hr/source)**	**PE2 (lb/day)**	**PE2 (lb/year)**
Valves (gas)	227	7.11E-05	0.7	312
Valves (light liquid)	75	7.11E-05	0.3	103
Pumps (light liquid)	2	2.23E-03	0.2	86
Compressor Seals (gas)	2	5.29E-04	0.1	20
Flanges (any)	1,109	1.17E-04	6.9	2,510

Total annual emissions from this permit unit are shown below:

Annual Emissions: Permit Unit N-9742-21				
Pollutant	**Heater (lb/year)**	**RTO #1 (lb/year)**	**Fugitives (lb/year)**	**PE2 (lb/year)**
NO_X	9,720	408	0	10,128
SO_X	20,470	195	0	20,665
PM_{10}	6,125	508	0	6,633
CO	29,013	247	0	29,260
VOC	443	369	3,030	3,842
NH_3	3,224	0	0	3,224

N-9742-22-0: Boiler

Emissions from the auxiliary boiler will be calculated using the following formulas:

Daily Emissions:

$PE2_{NOx}$ = 16 hr/day x Heat Input (MMBtu/hr) x $EF_{Steady\ State}$ (lb/MMBtu) + 8 hr/day x Heat Input x (MMBtu/hr) x $EF_{Startup/shutdown}$

`$PE2_{All\ other\ pollutants}$ = 24 hr/day x Heat Input (MMBtu/hr) x EF (lb/MMBtu)

Annual Emissions:

$PE2_{NOx}$ = 8,560 hr/year x Heat Input (MMBtu/hr) x $EF_{Steady\ State}$ (lb/MMBtu) + 200 hr/yr x Heat Input x (MMBtu/hr) x $EF_{Startup/shutdown}$

`$PE2_{All\ other\ pollutants}$ = 8,760 hr/yr x Heat Input (MMBtu/hr) x EF (lb/MMBtu)

Emissions: Auxiliary Boiler (59 MMBtu/hr)			
Pollutant	**Emission Factor (lb/MMBtu)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	0.003 (steady state) 0.061 (startup/shutdown)	31.6	2,235
SO_X	0.00285	4.0	1,473
PM_{10}	0.003	4.2	1,551
CO	0.018	25.5	9,303
VOC	0.00055	0.8	284
NH_3	0.0045	6.4	2,326

N-9742-23-0: Material Transfer Operation

Emissions from the regenerative thermal oxidizer are calculated using the following formulas:

Daily Emissions:

PE2 = 7.6 MMBtu/hr x 24 hr/day x $EF_{natural\ gas}$ + 792 MMBtu/day x $EF_{Process\ Gas}$

Annual Emissions:

PE2 = 7.6 MMBtu/hr x 8,760 hr/year x $EF_{natural\ gas}$ + 1,122 MMBtu/year x $EF_{Process\ Gas}$

Emissions: Regenerative Thermal Oxidizer #2			
Pollutant	**Emission Factor (lb/MMBtu)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	0.0061 (natural gas) 0.0058 (process gas)	5.7	413
SO_X	0.00285 (natural gas) 0.021 (process gas)	17.2	213
PM_{10}	0.0076 (natural gas and process gas)	7.4	515
CO	0.0037 (natural gas) 0.0035 (process gas)	3.4	250
VOC	0.0055 (natural gas) 0.0106 (process gas)	9.4	378

Emissions from product spillage during product hose disconnects are calculated as follows:

$PE2_{Daily}$ = #Disconnects/day x EF (lb/disconnect)
$PE2_{Annual}$ = #Disconnects/year x EF (lb/disconnect)

Emissions: Disconnects					
Material	**Disconnects per day**	**Disconnects per year**	**EF (lb/disconnect)**	**PE2 (lb/day)**	**PE2 (lb/year)**
Feedstock	120	20,000	0.021	2.5	420
Renewable Diesel and Sustainable Aviation Fuel	120	20,000	0.017*	2.0	340
Naphtha Byproduct	6	757	0.017	0.1	13

*Combined disconnects from Renewable Diesel and Sustainable Aviation fuel is 120/day and 20,000/year. The higher emission factor of the two products was used to determine worst-case emissions.

Emissions from fugitive components will be calculated as follows:

$PE2_{Daily}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 24 hr/day
$PE2_{Annual}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 8760 hr/yr

Emissions: Fugitive Components				
Pollutant	**Component Count**	**Leak Rate (kg/hr/source)**	**PE2 (lb/day)**	**PE2 (lb/year)**
Valves (gas)	8	7.11E-05	0.0	11
Valves (light liquid)	11	7.11E-05	0.0	15
Pumps (light liquid)	0	2.23E-03	0	0
Compressor Seals (gas)	0	5.29E-04	0	0
Flanges (any)	154	1.17E-04	1.0	348

Total annual emissions from this permit unit are shown below:

Annual Emissions: Permit Unit N-9742-23				
Pollutant	**RTO #1 (lb/year)**	**Disconnects (lb/year)**	**Fugitives (lb/year)**	**PE2 (lb/year)**
NO_X	413	0	0	413
SO_X	213	0	0	213
PM_{10}	515	0	0	515
CO	250	0	0	250
VOC	378	773	374	1,525
NH_3	0	0	0	0

N-9742-24-0: Wastewater Treatment Unit

Process vent emissions from the wastewater treatment unit will be controlled by regenerative thermal oxidizer #1, which is shared with unit N-9742-21-0. Since emissions from this unit have already been accounted for under permit unit N-9742-21-0, they will not be discussed any further under this unit.

Emissions from fugitive components will be calculated as follows:

$PE2_{Daily}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 24 hr/day
$PE2_{Annual}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 8760 hr/yr

Emissions: Fugitive Components				
Pollutant	**Component Count**	**Leak Rate (kg/hr/source)**	**PE2 (lb/day)**	**PE2 (lb/year)**
Valves (gas)	12	7.11E-05	0.0	17
Valves (light liquid)	20	7.11E-05	0.1	28
Pumps (light liquid)	0	2.23E-03	0	0
Compressor Seals (gas)	0	5.29E-04	0	0
Flanges (any)	217	1.17E-04	1.3	490

N-9742-25-0: Cooling Tower

Particulate emissions from the cooling tower are calculated using the following equations:

$$PE2\left(\frac{lb - PM_{10}}{day}\right) = Recirculation\ Rate\left(\frac{gal}{min}\right) \times 60\frac{min}{hr} \times Drift\ Rate\left(\frac{lb}{gal}\right) \times 24\frac{hr}{day}$$

$$PE2\left(\frac{lb - PM_{10}}{year}\right) = Recirculation\ Rate\left(\frac{gal}{min}\right) \times 60\frac{min}{hr} \times Drift\ Rate\left(\frac{lb}{gal}\right) \times 8{,}760\frac{hr}{year}$$

The following table shows the results of the daily and annual emission calculations for the cooling tower.

Emissions: Cooling Tower				
Pollutant	**Recirculation Rate (gal/min)**	**Drift Rate (lb/gal)**	**PE2 (lb/day)**	**PE2 (lb/year)**
PM_{10}	10,200	2.46E-08	0.4	132

N-9742-26-0: Emergency Flare

Emissions from the emergency flare will be calculated using the following formulas:

Daily Emissions:

`PE2 (lb/day) = 1,900 MMBtu/day x EF (lb/MMBtu)

Annual Emissions:

`PE2 (lb/year) = 7,400 MMBtu/year x EF (lb/MMBtu)

Emissions – Emergency Flare			
Pollutant	**Emission Factor (lb/MMBtu)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	0.068	129.2	503
SO_X	0.03	57.0	222
PM_{10}	0.05	95.0	370
CO	0.37	703.0	2,738
VOC	0.14	266.0	1,036

N-9742-27-0: Emergency Firewater Pump

Emissions from the emergency fire pump engine will be calculated using the following formulas:

Daily Emissions:

`PE2 (lb/day) = 687 BHP x 24 hr/day x EF (g/bhp-hr) x lb/453.6 g

Annual Emissions:

PE2 (lb/year) = 687 BHP x 50 hr/year x EF (g/bhp-hr) x lb/453.6 g

Emissions – Emergency Fire Pump Engine			
Pollutant	**Emission Factor (g/bhp-hr)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	2.65	96.3	201
SO_X	0.0051	0.2	0
PM_{10}	0.087	3.2	7
CO	0.92	33.4	70
VOC	0.06	2.2	5

N-9742-28-0: Emergency Electrical Generator

Emissions from the emergency generator engine will be calculated using the following formulas:

Daily Emissions:

`PE2 (lb/day) = 1,341 BHP x 24 hr/day x EF (g/bhp-hr) x lb/453.6 g

Annual Emissions:

PE2 (lb/year) = 1,341 BHP x 50 hr/year x EF (g/bhp-hr) x lb/453.6 g

Emissions – Emergency Generator Engine			
Pollutant	**Emission Factor (g/bhp-hr)**	**PE2 (lb/day)**	**PE2 (lb/year)**
NO_X	0.5	35.4	74
SO_X	0.0051	0.4	1
PM_{10}	0.022	1.6	3
CO	2.0	141.9	296
VOC	0.14	9.9	21

N-9742-29-0: Naphtha Storage Tank #1

Storage tank emissions were estimated using BREEZE Tanks ESP software (see Appendix D for Summary), which uses the latest EPA AP-42 equations to determine emissions. According to the tanks modeling data, the annual emissions from this tank is estimated to be 1,421 lb-VOC/year. Since working losses are minimal for internal floating roof tanks, the daily emissions are estimated to be 3.9 lb-VOC/day (1,421 lb-VOC/year ÷ 365 days/year).

PE2 = 3.9 lb-VOC/day
PE2 = 1,421 lb-VOC/year

In addition to emissions directly from the tank, there is fugitive emissions from components associated with the tank. The following fugitive component emissions are for the combined # of components associated with tanks N-9742-29-0 through '-32-0 and the fugitive emissions will be attributed to permit unit N-9742-29-0.

$PE2_{Daily}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 24 hr/day
$PE2_{Annual}$ = #Components x EF (kg/hr/source) x 2.205 lb/kg x 8760 hr/yr

Emissions: Fugitive Components				
Pollutant	**Component Count**	**Leak Rate (kg/hr/source)**	**PE2 (lb/day)**	**PE2 (lb/year)**
Valves (gas)	8	7.11E-05	0.0	11
Valves (light liquid)	11	7.11E-05	0.0	15
Pumps (light liquid)	0	2.23E-03	0	0
Compressor Seals (gas)	0	5.29E-04	0	0
Flanges (any)	154	1.17E-04	1.0	349

N-9742-30-0: Naphtha Storage Tank #2

Storage tank emissions were estimated using BREEZE Tanks ESP software (see Appendix D for Summary), which uses the latest EPA AP-42 equations to determine emissions. According to the tanks modeling data, the annual emissions from this tank is estimated to be 1,421 lb-VOC/year. Since working losses are minimal for internal floating roof tanks, the daily emissions are estimated to be 3.9 lb-VOC/day (1,421 lb-VOC/year ÷ 365 days/year).

PE2 = 3.9 lb-VOC/day
PE2 = 1,421 lb-VOC/year

Fugitive emissions from the tank associated with components such as valves, and flanges, were already calculated under Permit Unit N-9742-29-0.

N-9742-31-0: Slop Storage Tank #1

Storage tank emissions were estimated using BREEZE Tanks ESP software (see Appendix D for Summary), which uses the latest EPA AP-42 equations to determine emissions. According to the tanks modeling data, the annual emissions from this tank is estimated to be 26 lb-VOC/year. Since working losses are minimal for internal floating roof tanks, the daily emissions are estimated to be 0.1 lb-VOC/day (26 lb-VOC/year ÷ 365 days/year).

PE2 = 0.1 lb-VOC/day
PE2 = 26 lb-VOC/year

Fugitive emissions from the tank associated with components such as valves, and flanges, were already calculated under Permit Unit N-9742-29-0.

N-9742-32-0: Slop Storage Tank #2

Storage tank emissions were estimated using BREEZE Tanks ESP software (see Appendix D for Summary), which uses the latest EPA AP-42 equations to determine emissions. According to the tanks modeling data, the annual emissions from this tank is estimated to be 30 lb-VOC/year. Since working losses are minimal for internal floating roof tanks, the daily emissions are estimated to be 0.1 lb-VOC/day (26 lb-VOC/year ÷ 365 days/year).

PE2 = 0.1 lb-VOC/day
PE2 = 30 lb-VOC/year

Fugitive emissions from the tank associated with components such as valves, and flanges, were already calculated under Permit Unit N-9742-29-0.

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.

ATC's N-9742-1-0 through '-19-0 are expired; therefore, these ATCs are not valid and will not be included in SSPE1. SSPE1 is equal to zero.

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

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

SSPE2 (lb/year)						
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**	**NH_3**
N-9742-20-0	3,873	2,212	2,328	13,971	7,345	1,708
N-9742-21-0	10,128	20,665	6,633	29,260	3,842	3,224
N-9742-22-0	2,235	1,473	1,551	9,303	284	2,326
N-9742-23-0	413	213	515	250	1,525	0
N-9742-24-0*	0	0	0	0	535	0
N-9742-25-0	0	0	132	0	0	0
N-9742-26-0	503	222	370	2,738	1,036	0
N-9742-27-0	201	0	7	70	5	0
N-9742-28-0	74	1	3	296	21	0
N-9742-29-0	0	0	0	0	1,796	0
N-9742-30-0	0	0	0	0	1,421	0
N-9742-31-0	0	0	0	0	26	0
N-9742-32-0	0	0	0	0	30	0
SSPE2	**17,427**	**24,786**	**11,539**	**55,888**	**17,866**	**7,258**

*Emissions from shared RTO #1 (serving the process vents on the wastewater treatment plant permitted as N-9742-24-0) are already accounted for in the emissions shown for permit unit N-9742-21-0.

5. Major Source Determination

Rule 2201 Major Source Determination:

Identify if the source will be a Major Source for Rule 2201 (post project).

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

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1	0	0	0	0	0	0
SSPE2	17,427	24,786	11,539	11,539	55,888	17,866
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No	No

Note: PM2.5 assumed to be equal to PM10

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

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore, the PSD Major Source threshold is 100 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	100	100	100	100	100	100
PSD Major Source?	No	No	No	No	No	No

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

6. Baseline Emissions (BE)

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

Pursuant to District Rule 2201, BE = PE1 for:

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

Otherwise,

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

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

Therefore BE = PE1.

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.

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

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification and no further discussion is required.

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).

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

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

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

I. Project Emissions Increase - New Major Source Determination

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

The equipment evaluated under this project is listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). The PSD Major Source threshold is 100 tpy for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Total PE from New and Modified Units	8.7	8.9	12.4	27.9	5.8	5.8
PSD Major Source threshold	100	100	100	100	100	100
New PSD Major Source?	No	No	No	No	No	No

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 I.

11. PM2.5 Federal Offset Sanctions

As of June 27, 2023, the District is in nonattainment new source review (NNSR) offset sanctions pursuant to CAA 179(a) for PM2.5. Therefore, any New Major Source or Federal Major Modification for PM2.5 (including increases of its precursors NOx, VOC, and SOx), must supply any required federal offsets at a 2:1 ratio.

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

PM2.5 Federal Major Source Determination (lb/year)				
	NO_X*	**SO_X***	**$PM_{2.5}$**	**VOC***
SSPE1	0	0	0	0
SSPE2	17,427	24,786	11,539	17,866
PM2.5 Federal Major Source Threshold**	140,000	140,000	140,000	140,000
Pre or Post-Project PM2.5 Federal Major Source?	No	No	No	No

* PM2.5 Precursors
** Pursuant to 40 CFR 51.165(a)(1)(iv)(A)

As shown in the table above, this facility is not an existing or becoming a Major Source for PM2.5, NOx, SOx, or VOC, as a result of this project; therefore, the 2:1 federal offset sanctions are not applicable.

VIII. Compliance Determination

Rule 2010 Permits Required

This proposed operation includes four 35,700 bbl feedstock tanks, two 7,150 bbl blend tanks, and two 7,150 bbl buffer tanks. These tanks store rendered animal fats (beef tallow) and vegetable oils, which are solid or a gel at lower temperatures (typically 65 °F to 70 °F). The tanks are each steam-jacketed to maintain a temperature of 80 °F to ensure that the materials are viscous enough to transfer in and out of the tanks. The vapor pressure for the feedstocks is expected to be minimal. The vapor pressure of vegetable oil was previously determined to be approximately 0.0028 psia at a temperature of 120 °F and the vapor pressure of beef tallow is expected to be similar. By the way of comparison, the vapor pressure of distillate fuel oil #2 (i.e. diesel) at 120 °F has a vapor pressure of 0.022 psia. The District considers diesel to be essentially non-volatile and does not require permits for equipment that stores diesel. Since vegetable oil and beef tallow have lower vapor pressures than diesel, they are also considered to be essentially non-volatile materials. Therefore, no emissions are expected from the proposed tanks mentioned above, and permits will not be required for the tanks.

Rule 2020 Exemptions

The proposed operation includes various tote tanks with a capacity less than 250 gallons. These tote tanks are exempt from permits pursuant to Section 6.6.4 of Rule 2020, which exempts the storage of organic material with a capacity of 250 gallons or less where the actual storage temperature does not exceed 150 °F.

The proposed operation will include four 1,012,200 gallon internal floating roof storage tanks that will store either renewable diesel or sustainable aviation fuels that are produced at this site. These tanks are unheated and the initial boiling point of the renewable diesel and sustainable aviation fuels produced at this site will be greater than 302 °F. Pursuant to District Rule 2020, Section 6.6.5, organic liquid storage tanks used to store unheated material with an initial boiling point equal to or greater than 302 °F are categorically exempt from permits. Therefore, these tanks do not require a permit and no further discussion is necessary for these tanks.

Rule 2201 New and Modified Stationary Source Review Rule

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

N-9742-20-0: HydroFlex Fuel Production Unit

Emissions from the 19.5 MMBtu/hr process heater are greater than 2.0 lb/day for NOx and CO; however, the facility-wide emissions for CO are less than 200,000 lb/year. Therefore, BACT is only triggered for NOx emissions from this heater (#1).

Emissions from the 27.6 MMBtu/hr process heater are greater than 2.0 lb/day for NOx and CO; however, the facility-wide emissions for CO are less than 200,000 lb/year. Therefore, BACT is only triggered for NOx emissions from this heater (#2).

Emissions from the 41.5 MMBtu/hr process heater are greater than 2.0 lb/day for NOx, SOx, PM_{10}, CO, and NH3; however, the facility-wide emissions for CO are less than 200,000 lb/year and NH_3 emissions are emitted from the control system rather than the emission unit itself. Therefore, BACT is only triggered for NOx, SOx and PM_{10} emissions from this heater (#3).

VOC emissions from fugitive components are greater than 2.0 lb/day. Therefore, BACT is triggered for VOC emissions from fugitive components.

N-9742-21-0: Hydrogen Production Unit

Emissions from the process heater are greater than 2.0 lb/day for NOx, SOx, PM_{10}, CO, and NH_3; however, CO emissions from the facility are less than 200,000 lb/year and NH_3 emissions are emitted from the control system rather than the emission unit itself. Therefore, BACT is only triggered for NOx, SOx, and PM_{10} emissions from the process heater.

The hydrogen production unit process emissions are combined with the wastewater treatment unit process emissions (N-9742-24-0), which are then controlled by RTO #1. These units emit VOC with an emission rate greater than 2.0 lb/day; therefore, BACT is triggered for VOC emissions from these units.

VOC emissions from fugitive components are greater than 2.0 lb/day. Therefore, BACT is triggered for VOC emissions from fugitive components.

N-9742-22-0: Boiler

Emissions from the boiler are greater than 2.0 lb/day for NOx, SOx, PM_{10}, CO, and NH_3; however, CO emissions from the facility are less than 200,000 lb/year and NH_3 emissions are emitted from the control system rather than the emission unit itself. Therefore, BACT is only triggered for NOx, SOx, and PM_{10} emissions from the boiler.

N-9742-23-0: Material Transfer Operation

The material transfer operation, including product transfer and disconnects, emits greater than 2.0 lb/day of VOC emissions. Therefore, BACT is triggered for the material transfer operation.

Emissions from fugitive components are less than 2.0 lb/day; therefore, BACT is not triggered for fugitive components associated with the material transfer operation.

N-9742-24-0: Wastewater Treatment Unit

Process vent emissions from the wastewater treatment unit are combined with the process emissions for the hydrogen production unit. The VOC emission rate is greater than 2.0 lb/day; therefore, BACT is triggered for VOC emissions.

Emissions from fugitive components are less than 2.0 lb/day; therefore, BACT is not triggered for fugitive components associated with the wastewater treatment unit.

N-9742-25-0: Cooling Tower

Emissions from the cooling tower are less than 2.0 lb/day; therefore, BACT is not triggered for the cooling tower.

N-9742-26-0: Emergency Flare

The emergency flare is not an emission unit. Rather, it serves as a backup control device in the event that the primary control systems (Thermal oxidizers) are out of service. Since BACT is only applicable to emission units, it is not applicable to this device.

While BACT is not applicable to the emergency flare, the District did evaluate whether an ultra-low NOx flare may be feasible for such an operation. Pursuant to the District's staff report for District Rule 4311 in 2020, ultra-low NOx flares require a start-up time of 30 to 60 minutes prior to introducing gas to the flare, and are therefore not feasible for applications where flaring of gas is needed immediately. The emergency flare in this proposal requires immediate flaring to prevent situations that could result in catastrophic failure of the plant. Therefore, an ultra-low NOx flare is not feasible for this project proposal.

N-9742-27-0: Emergency Firewater Pump

Emissions from the engine powering the firewater pump are greater than 2.0 lb/day for NOx, PM_{10}, CO, and VOC; however, facility-wide CO emissions are less than 200,000 lb/year. Therefore, BACT is only triggered NOx, PM_{10}, and VOC.

N-9742-28-0: Emergency Electrical Generator

Emissions from the engine powering the emergency generator are greater than 2.0 lb/day for NOx, CO, and VOC; however, facility-wide CO emissions are less than 200,000 lb/year. Therefore, BACT is only triggered NOx and VOC.

N-9742-29-0: Naphtha Storage Tank #1

Emissions from the organic liquid storage tank are greater than 2.0 lb-VOC/day; therefore, BACT is triggered for VOC emissions from this tank.

Emissions from fugitive components associated with the tank are less than 2.0 lb/day; therefore, BACT is not triggered for fugitive components.

N-9742-30-0: Naphtha Storage Tank #2

Emissions from the organic liquid storage tank are greater than 2.0 lb-VOC/day; therefore, BACT is triggered for VOC emissions from this tank.

Emissions from fugitive components associated with the tank are less than 2.0 lb/day; therefore, BACT is not triggered for fugitive components.

N-9742-31-0: Slop Storage Tank #1

Emissions from the organic liquid storage tank are less than 2.0 lb-VOC/day; therefore, BACT is not triggered for VOC emissions from this tank.

Emissions from fugitive components associated with the tank are less than 2.0 lb/day; therefore, BACT is not triggered for fugitive components.

N-9742-32-0: Slop Storage Tank #2

Emissions from the organic liquid storage tank are less than 2.0 lb-VOC/day; therefore, BACT is not triggered for VOC emissions from this tank.

Emissions from fugitive components associated with the tank are less than 2.0 lb/day; therefore, BACT is not triggered for fugitive components.

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 a relocated 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 AIPE purposes.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB288 Modification or Federal Major Modification for any pollutant. Therefore, BACT is not triggered for SB288/Federal Major Modification purposes.

2. BACT Guideline

<u>N-9742-20-0: HydroFlex Fuel Production Unit</u>

BACT Guideline 1.8.5, *Process heaters with heat input =< 20 MMBtu/hr (3/29/2023)*, is applicable to the 19.5 MMBtu/hr natural gas-fired process heater. A copy of this guideline is included in Appendix E.1.

The BACT Clearinghouse does not currently include a BACT Guideline for process heaters rated greater than 20 MMBtu/hr. Therefore, a new BACT analysis will be performed for the 27.6 and 41.5 MMBtu/hr process heaters (see Appendix E.2).

BACT Guideline 4.12.1, *Chemical Plants – Valves & Connectors (11/26/2006)*, and BACT Guideline 4.12.2, <u>Chemical Plants Pump and Compressor Seals (11/27/2006)</u>, are applicable to the fugitive components associated with the HydroFlex fuel production unit. Since these BACT Guidelines were each last updated more than five years ago, the Guidelines will be proactively updated in this permitting action (see Appendices E.4 and E.5)

<u>N-9742-21-0: Hydrogen Production Unit</u>

The BACT Clearinghouse does not currently include a BACT Guideline for hydrogen production process heaters rated greater than 20 MMBtu/hr. Therefore, a new BACT analysis will be performed for this equipment (see Appendix E.3).

BACT Guideline 4.12.1, *Chemical Plants – Valves & Connectors (11/26/2006)*, and BACT Guideline 4.12.2, <u>Chemical Plants Pump and Compressor Seals (11/27/2006)</u>, are applicable to the fugitive components associated with the Hydrogen production unit. Since these BACT Guidelines were each last updated more than five years ago, the Guidelines will be proactively updated in this permitting action (see Appendices E.4 and E.5)

The District's BACT Clearinghouse does not include a BACT for hydrogen production process vents. A new BACT has been prepared for this equipment. Please refer to Appendix E.6 of this evaluation.

<u>N-9742-22-0: Boiler</u>

BACT Guideline 1.1.2, *Natural gas or propane fired boilers/steam generators with heat input rate greater than 20 MMBtu/hr (11/30/22)*, is applicable to the boiler. For a copy of this guideline, see Appendix E.7.

<u>N-9742-23-0: Material Transfer Operation</u>

BACT Guideline 7.1.10, *Organic Liquid Loading Rack (7/19/2018)*, is applicable to the material transfer operation. A copy of this guideline is included in Appendix E.8.

<u>N-9742-24-0: Wastewater Treatment Unit</u>

The District's BACT Clearinghouse does not include a BACT Guideline treatment plant process vents. Therefore, a new BACT analysis will be performed in this project for this type of emission unit (See Appendix E.6)

<u>N-9742-27-0: Emergency Firewater Pump</u>

BACT Guideline 3.1.4, *Emergency Diesel-Fired IC Engine Powering a Fire Pump (3/2/2020)*, is applicable to the emergency fire pump engine in this project. A copy of the BACT Guideline is included in Appendix E.9.

<u>N-9742-28-0: Emergency Electrical Generator</u>

BACT Guideline 3.1.1, *Emergency Diesel-Fired IC Engine > 50 bhp Powering an Electrical Generator (4/29/2022)*, is applicable to the emergency generator engine. A copy of the BACT Guideline is included in Appendix E.10.

<u>N-9742-29-0: Naphtha Storage Tank #1</u>

BACT Guideline 7.3.3, *Floating Roof Organic Liquid Storage or Processing Tank (9/1/2021)*, is applicable to this tank. A copy of the BACT Guideline is included in Appendix E.11.

<u>N-9742-30-0: Naphtha Storage Tank #2</u>

BACT Guideline 7.3.3, *Floating Roof Organic Liquid Storage or Processing Tank (9/1/2021)*, is applicable to this tank. A copy of the BACT Guideline is included in Appendix E.11.

3. Top-Down BACT Analysis

N-9742-20-0: HydroFlex Fuel Production Unit

Pursuant to the Top-Down BACT Analysis in Appendix E.1, BACT for the 19.5 MMBtu/hr process heater is satisfied with the following:

NOx: 5 ppmvd @ 3% O_2 (0.0061 lb/MMBtu)

Pursuant to the Top-Down BACT Analysis in Appendix E.2, BACT for the 27.6 MMBtu/hr process heater is satisfied with the following:

NOx: 2.5 ppmvd @ 3% O_2 (0.003 lb/MMBtu)

Pursuant to the Top-Down BACT Analysis in Appendix E.2, BACT for the 41.5 MMBtu/hr process heater is satisfied with the following:

NOx: 2.5 ppmvd @ 3% O_2 (0.003 lb/MMBtu)
PM10: Use of natural gas fuel

Pursuant to the Top-Down BACT Analyses in Appendices E.4 and E.5, BACT for the fugitive VOC emissions from components is satisfied with the following:

Valves and Connectors: Leak defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 and maintenance program pursuant to District Rule 4455.

Pumps and Compressor Seals: Leak defined as a reading of methane in excess of 500 ppmv above background when measured per EPA Method 21 and maintenance program pursuant to District Rule 4455.

N-9742-21-0: Hydrogen Production Unit

Waste- Gas Fired Process Heater

Pursuant to the Top-Down BACT Analysis in Appendix E.3, BACT is satisfied with the following:

NOx: 2.5 ppmvd @ 3% O_2 (0.003 lb/MMBtu)
SOx: Compliance with District Rule 4320 Requirements
PM10: 0.0039 lb-PM10/MMBtu

Fugitive Emissions:

Pursuant to the Top-Down BACT Analyses in Appendices E.4 and E.5, BACT for the fugitive VOC emissions from components is satisfied with the following:

Valves and Connectors: Leak defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 and maintenance program pursuant to District Rule 4455.

Pumps and Compressor Seals: Leak defined as a reading of methane in excess of 500 ppmv above background when measured per EPA Method 21 and maintenance program pursuant to District Rule 4455.

Process Vents

Pursuant to the BACT analysis in Appendix E.6, BACT is satisfied with the following:

VOC: Use of a Thermal Oxidizer with 99% capture and control

N-9742-22-0: Boiler

Pursuant to the Top-down BACT Analysis in Appendix E.7, BACT is satisfied with the following:

NOx: 2.5 ppmvd @ 3% O_2 (0.003 lb/MMBtu)
SOx: PUC quality natural gas
PM10: PUC quality natural gas

N-9742-23-0: Material Transfer Operation

Pursuant to the Top-down BACT Analysis in Appendix E.8, BACT is satisfied with the following:

VOC: Bottom fill loading with dry break couplers, or equivalent, and VOC emissions from the vapor collection and control system less than or equal to 0.015 pounds per 1000 gallons of organic liquid transferred

N-9742-24-0: Wastewater Treatment Unit

Pursuant to the Top-Down BACT Analysis in Appendix E.6, BACT for the wastewater treatment unit vents is satisfied with the following:

VOC: Use of a Thermal Oxidizer with 99% capture and control

N-9742-27-0: Emergency Firewater Pump

Pursuant to the Top-Down BACT Analysis in Appendix E.9, BACT for the fire pump engine is satisfied with the following:

NOx: Use of a Tier 3 certified engine
PM10: 0.15 g/bhp-hr
VOC: Use of a Tier 3 certified engine

N-9742-28-0: Emergency Electrical Generator

Pursuant to the Top-Down BACT Analysis in Appendix E.10, BACT for the emergency engine powering a generator is satisfied with the following:

NOx: Use of a Tier 4 final certified engine
VOC: Use of a Tier 4 final certified engine

N-9742-29-0: Naphtha Storage Tank #1

Pursuant to the Top-Down BACT Analysis in Appendix E.11, BACT for the organic liquid storage tank is satisfied with the following:

VOC: Use of an internal floating roof meeting the requirements of District Rule 4623

N-9742-30-0: Naphtha Storage Tank #2

Pursuant to the Top-Down BACT Analysis in Appendix E.11, BACT for the organic liquid storage tank is satisfied with the following:

VOC: Use of an internal floating roof meeting the requirements of District Rule 4623

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	17,427	24,786	11,539	55,888	17,866
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets Triggered?	No	No	No	No	No

2. Quantity of District Offsets Required

As demonstrated above, District offsets are not triggered for any pollutant; therefore, offsets are not required.

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 shown in Section VII.C.5 above, this existing minor source facility is not becoming a Major Source as a result of this project. Therefore, this facility is not a New Major Source and this project does not constitute an SB 288 or a Federal Major Modification. Consequently, public noticing for this project for New Major Source, Federal Major Modification, or SB 288 Major Modification purposes is not required.

b. PE > 100 lb/day

For new emissions units, public notification is required if the PE exceeds 100 lb/day for any pollutant. This project includes a 184 MMBtu/hr process heater with NOx and SOx emissions greater than 100 lb/day and an emergency flare with NOx, CO, and VOC emissions greater than 100 lb/day. Therefore, public noticing for PE > 100 lb/day purposes is required.

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	0	17,427	20,000 lb/year	No
SO_X	0	24,786	54,750 lb/year	No
PM_{10}	0	11,539	29,200 lb/year	No
CO	0	55,888	200,000 lb/year	No
VOC	0	17,866	20,000 lb/year	No

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

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_x	17,427	0	17,427	20,000 lb/year	No
SO_x	24,786	0	24,786	20,000 lb/year	Yes
PM_{10}	11,539	0	11,539	20,000 lb/year	No
CO	55,888	0	55,888	20,000 lb/year	Yes
VOC	17,866	0	17,866	20,000 lb/year	No
NH_3	7,258	0	7,258	20,000 lb/year	No

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

e. Title V Significant Permit Modification

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

2. Public Notice Action

As discussed above, public noticing is required for this project for emission units with emissions in excess of 100 lb/day and SSIPE in excess of 20,000 lb/year. 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.

<u>N-9742-20-0: HydroFlex Fuel Production Unit</u>

- Each of the three process heaters shall only be fired on PUC quality natural gas. [*District Rules 2201, 4305, 4306, and 4320]*

- *The total combined duration of startup and shutdowns for the 19.5 MMBtu/hr process heater shall not exceed 8 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 8 hours and the duration of each individual shutdown event shall not exceed 2 hours. [District Rules 2201, 4305, 4306, and 4320]*

- *Except during startup and shutdown, emissions from the 19.5 MMBtu/hr process heater shall not exceed 5 ppmvd NOx @ 3% O2 or 0.0061 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *During startup and shutdown, emissions from the 19.5 MMBtu/hr process heater shall not exceed 50 ppmvd NOx @ 3% O2 or 0.061 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *Emissions from the 19.5 MMBtu/hr process heater shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.00285 lb-SOx/MMBtu, 0.00055 lb-VOC/MMBtu, 0.003 lb-PM10/MMBtu, and 5 ppmvd NH3 @ 3% O2 or 0.0022 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *The total combined duration of startup and shutdowns for the 27.6 MMBtu/hr process heater shall not exceed 8 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 8 hours and the duration of each individual shutdown event shall not exceed 2 hours. [District Rules 2201, 4305, 4306, and 4320]*

- *Except during startup and shutdown, emissions from the 27.6 MMBtu/hr process heater shall not exceed 2.5 ppmvd NOx @ 3% O2 or 0.003 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *During startup and shutdown, emissions from the 27.6 MMBtu/hr process heater shall not exceed 50 ppmvd NOx @ 3% O2 or 0.061 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *Emissions from the 27.6 MMBtu/hr process heater shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.00285 lb-SOx/MMBtu, 0.00055 lb-VOC/MMBtu, 0.003 lb-PM10/MMBtu, and 5 ppmvd NH3 @ 3% O2 or 0.0022 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *The total combined duration of startup and shutdowns for the 41.5 MMBtu/hr process heater shall not exceed 8 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 8 hours and the duration of each individual shutdown event shall not exceed 2 hours. [District Rules 2201, 4305, 4306, and 4320]*

- *Except during startup and shutdown, emissions from the 41.5 MMBtu/hr process heater shall not exceed 2.5 ppmvd NOx @ 3% O2 or 0.003 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *During startup and shutdown, emissions from the 41.5 MMBtu/hr process heater shall not exceed 50 ppmvd NOx @ 3% O2 or 0.061 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *Emissions from the 41.5 MMBtu/hr process heater shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.00285 lb-SOx/MMBtu, 0.00055 lb-VOC/MMBtu, 0.003 lb-PM10/MMBtu, and 5 ppmvd NH3 @ 3% O2 or 0.0022 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *For each of the three process heaters, the emission control system shall be in operation and emissions shall be minimized insofar as technologically possible during startup and shutdown of the unit. [District Rules 2201, 4305, 4306, and 4320]*

- *Total fugitive VOC emissions from the HydroFlex unit shall not exceed 19.1 lb/day and 6,918 lb/rolling 12-month period. [District Rule 2201]*

- *Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]*

- *Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rule 2201]*

- *Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]*

<u>N-9742-21-0: Hydrogen Production Unit</u>

- The process heater shall only be fired on PUC quality natural gas and process gas. [*District Rules 2201, 4305, 4306, and 4320]*

- *The sulfur content of the process gas supplied to the process heater shall not exceed 1.75 grains/100 dscf. [District Rule 2201]*

- *The total combined duration of startup and shutdowns for the process heater shall not exceed 12 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 12 hours and the duration of each individual shutdown event shall not exceed 2 hours. [District Rules 2201, 4305, 4306, and 4320]*

- *Except during startup and shutdown, emissions from the process heater shall not exceed 2.5 ppmvd NOx @ 3% O2 or 0.0029 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *During startup and shutdown, emissions from the process heater shall not exceed 0.14 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *The total combined duration of startup and shutdowns for the process heater shall not exceed 12 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. [District Rules 2201, 4305, 4306, and 4320]*

- *Emissions from the process heater shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.0127 lb-SOx/MMBtu, 0.000275 lb-VOC/MMBtu, 0.0038 lb-PM10/MMBtu, and 5 ppmvd NH3 @ 3% O2 or 0.002 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *For the process heater, the emission control system shall be in operation and emissions shall be minimized insofar as technologically possible during startup and shutdown of the unit. [District Rules 2201, 4305, 4306, and 4320]*

- *The regenerative thermal oxidizer shall only be fired on PUC-Quality natural gas as a supplemental fuel. [District Rule 2201]*

- *Natural gas combustion emissions from the regenerative thermal oxidizer serving the hydrogen production unit and the wastewater treatment plant (N-9742-24) shall not exceed any of the following: 5 ppmvd NOx @ 3% O_2 or 0.0061 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0037 lb-CO/MMBtu, and 0.0055 lb-VOC/MMBtu. [District Rule 2201]*

- *The heat input from the process gas into the regenerative thermal oxidizer shall not exceed 270 MMBtu/day and shall not exceed 270 MMBtu/rolling 12-month period. [District Rule 2201]*

- *Process gas combustion emissions from the regenerative thermal oxidizer serving the hydrogen production unit and the wastewater treatment plant (N-9742-24) shall not exceed any of the following: 5 ppmv NOx @ 3% O_2 or 0.0058 lb-NOx/MMBtu, 0.021 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0035 lb-CO/MMBtu, and 0.0106 lb-VOC/MMBtu. [District Rule 2201]*

- *The sulfur content of process gas routed to the regenerative thermal oxidizer shall not exceed 1.75 grains/100 scf. [District Rule 2201]*

- *Total fugitive VOC emissions from the hydrogen production unit shall not exceed 8.2 lb/day and 3,031 lb/rolling 12-month period. [District Rule 2201]*

- *Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]*

- *Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rule 2201]*

- *Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]*

N-9742-22-0: Boiler

- The boiler shall only be fired on PUC quality natural gas. [*District Rules 2201, 4305, 4306, and 4320, and 40 CFR 60 Subpart Dc]*

- *The total combined duration of startup and shutdowns for the boiler shall not exceed 8 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 8 hours and the duration of each individual shutdown event shall not exceed 2 hours. [District Rules 2201, 4305, 4306, and 4320]*
- *Except during startup and shutdown, emissions from the boiler shall not exceed 2.5 ppmvd NOx @ 3% O2 or 0.003 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *During startup and shutdown, emissions from the boiler shall not exceed 50 ppmvd @ 3% O2 or 0.062 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *Emissions from the boiler shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.00285 lb-SOx/MMBtu, 0.00055 lb-VOC/MMBtu, 0.003 lb-PM10/MMBtu, and 10 ppmvd NH3 @ 3% O2 or 0.0045 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306, and 4320]*

- *The emission control system shall be in operation and emissions shall be minimized insofar as technologically possible during startup and shutdown of the unit. [District Rules 2201, 4305, 4306, and 4320]*

N-9742-23-0: Material Transfer Operation

- *The regenerative thermal oxidizer shall only be fired on PUC-Quality natural gas as a supplemental fuel. [District Rule 2201]*

- *Natural gas combustion emissions from the regenerative thermal oxidizer serving the material transfer operations shall not exceed any of the following: 5 ppmvd NOx @ 3% O_2 or 0.0061 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0037 lb-CO/MMBtu, and 0.0055 lb-VOC/MMBtu. [District Rule 2201]*

- *The heat input from the process gas into the regenerative thermal oxidizer shall not exceed 792 MMBtu/day and shall not exceed 1,122 MMBtu/rolling 12-month period. [District Rule 2201]*

- *Process gas combustion emissions from the regenerative thermal oxidizer serving the material transfer operations shall not exceed any of the following: 5 ppmv NOx @ 3% O_2 or 0.0058 lb-NOx/MMBtu, 0.021 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0035 lb-CO/MMBtu, and 0.0106 lb-VOC/MMBtu. [District Rule 2201]*

- *The sulfur content of process gas routed to the regenerative thermal oxidizer shall not exceed 1.75 grains/100 dscf. [District Rule 2201]*

- *The quantity of disconnects associated with the transfer of feedstocks shall not exceed 120 in any one day and 20,000 in any rolling 12-month period. [District Rule 2201]*

- *Emissions from disconnects associated with the transfer of feedstocks shall not exceed 0.021 lb-VOC/disconnect. [District Rule 2201]*

- *The quantity of disconnects associated with the transfer of renewable diesel and sustainable aviation fuel shall not exceed 120 in any one day and 20,000 in any rolling 12-month period. [District Rule 2201]*

- *Emissions from disconnects associated with the transfer of renewable diesel and sustainable aviation fuel shall not exceed 0.017 lb-VOC/disconnect. [District Rule 2201]*

- *The quantity of disconnects associated with the transfer of naphtha shall not exceed 6 in any one day and 757 in any rolling 12-month period. [District Rule 2201]*

- *Emissions from disconnects associated with the transfer of naphtha shall not exceed 0.017 lb-VOC/disconnect. [District Rule 2201]*

- *Total fugitive VOC emissions from the material transfer operations shall not exceed 1.0 lb/day and 374 lb/rolling 12-month period. [District Rule 2201]*

- *Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]*

- *Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rule 2201]*

- *Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]*

N-9742-24-0: Wastewater Treatment Unit

- *The regenerative thermal oxidizer shall only be fired on PUC-Quality natural gas as a supplemental fuel. [District Rule 2201]*

- *Natural gas combustion emissions from the regenerative thermal oxidizer serving the hydrogen production unit (N-9742-21) and the wastewater treatment plant shall not exceed any of the following: 5 ppmvd NOx @ 3% O_2 or 0.0061 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0037 lb-CO/MMBtu, and 0.0055 lb-VOC/MMBtu. [District Rule 2201]*

- *The heat input from the process gas into the regenerative thermal oxidizer shall not exceed 270 MMBtu/day and shall not exceed 270 MMBtu/rolling 12-month period. [District Rule 2201]*

- *Process gas combustion emissions from the regenerative thermal oxidizer serving the hydrogen production unit (N-9742-21) and the wastewater treatment plant shall not exceed any of the following: 5 ppmv NOx @ 3% O_2 or 0.0058 lb-NOx/MMBtu, 0.021 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0035 lb-CO/MMBtu, and 0.0106 lb-VOC/MMBtu. [District Rule 2201]*

- *The sulfur content of process gas routed to the regenerative thermal oxidizer shall not exceed 1.75 grains/100 dscf. [District Rule 2201]*

- *Total fugitive VOC emissions from the wastewater treatment plant shall not exceed 1.4 lb/day and 535 lb/rolling 12-month period. [District Rule 2201]*

- *Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]*

- *Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rule 2201]*

- *Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]*

N-9742-25-0: Cooling Tower

- The cooling tower shall be equipped with a drift eliminator that reduces drift to less than or equal to 0.0005%. [District Rule 2201]

- PM10 emissions from the cooling tower shall not exceed 0.4 pounds in any one day. [District Rule 2201]

- Compliance with the daily emissions limitation shall be demonstrated on a quarterly basis using the daily PM10 emission rate calculated as follows: blowdown water TDS (ppmv) ÷ 10^6 x cooling water recirculation rate (gal/day) x design drift rate (%) ÷ 100 x water density (lb/gal). [District Rules 1070 and 2201]

N-9742-26-0: Emergency Flare

- *The emergency flare shall only be fired on PUC-Quality natural gas as a supplemental fuel. [District Rule 2201]*

- *The heat input for the emergency flare shall not exceed 1,900 MMBtu in any one day and shall not exceed 7,400 MMBtu in any rolling 12-month period. [District Rule 2201]*

- *Emissions from the emergency flare shall not exceed any of the following: 0.0068 lb-NOx/MMBtu, 0.03 lb-SOx/MMBtu, 0.05 lb-PM10/MMBtu, 0.37 lb-CO/MMBtu, and 0.14 lb-VOC/MMBtu. [District Rule 2201]*

N-9742-27-0: Emergency Firewater Pump

- *Emissions from this IC engine shall not exceed any of the following limits: 2.65 g-NOx/bhp-hr, 0.92 g-CO/bhp-hr, or 0.06 g-VOC/bhp-hr. [District Rule 2201 and 17 CCR 93115]*

- *{4772} Emissions from this IC engine shall not exceed 0.087 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102, and 17 CCR 93115]*

- *{4258} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801, and 17 CCR 93115]*

N-9742-28-0: Emergency Electrical Generator

- *Emissions from this IC engine shall not exceed any of the following limits: 0.5 g-NOx/bhp-hr, 2.0 g-CO/bhp-hr, or 0.14 g-VOC/bhp-hr. [District Rule 2201 and 17 CCR 93115]*

- *{4772} Emissions from this IC engine shall not exceed 0.022 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102, and 17 CCR 93115]*

- *{4258} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801, and 17 CCR 93115]*

N-9742-29-0: Naphtha Storage Tank #1

- *Only naphtha shall be stored in this tank. [District Rule 2201]*

- *VOC emissions from this tank shall not exceed 3.9 lb in any one day and shall not exceed 1,421 lb in any rolling 12-month period. [District Rule 2201]*

- *The quantity of naphtha loaded into this tank shall not exceed 212,795 bbl in any rolling 12-month period. [District Rule 2201]*

- *Total fugitive VOC emissions from components associated with tanks N-9742-29, '-30, '-31, and '-32 shall not exceed 1.0 lb/day and 375 lb/rolling 12-month period. [District Rule 2201]*

- *Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]*

- *Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rule 2201]*

- *Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]*

N-9742-30-0: Naphtha Storage Tank #2

- *Only naphtha shall be stored in this tank. [District Rule 2201]*

- *VOC emissions from this tank shall not exceed 3.9 lb in any one day and shall not exceed 1,421 lb in any one rolling 12-month period. [District Rule 2201]*

- *The quantity of naphtha loaded into this tank shall not exceed 212,795 bbl in any rolling 12-month period. [District Rule 2201]*

N-9742-31-0: Slop Storage Tank #1

- *Only off-specification product (aka Slop) shall be stored in this tank. [District Rule 2201]*

- *VOC emissions from this tank shall not exceed 0.1 lb in any one day and shall not exceed 26 lb in any rolling 12-month period. [District Rule 2201]*

- *The quantity of slop loaded into this tank shall not exceed 7,300 bbl in any rolling 12-month period. [District Rule 2201]*

N-9742-32-0: Slop Storage Tank #2

- *Only off-specification product (aka Slop) shall be stored in this tank. The true vapor pressure of the Slop shall not exceed 0.5 psia. [District Rules 2201 and 4623, and 40 CFR 60 Subpart Kb]*

- *VOC emissions from this tank shall not exceed 0.1 lb-VOC in any one day and shall not exceed 30 lb in any rolling 12-month period. [District Rule 2201]*

- *The quantity of slop loaded into this tank shall not exceed 14,300 bbl in any rolling 12-month period. [District Rule 2201]*

E. Compliance Assurance

1. Source Testing

N-9742-20-0: HydroFlex Fuel Production Unit

Each process heater is equipped with a selective catalytic reduction system to reduce NOx emissions and is equipped with an oxidation catalyst to reduce CO and VOC emissions. Initial and periodic testing of NOx, CO, and VOC will be required to ensure these controls are operating properly. Furthermore, the selective catalytic reduction system utilizes ammonia injection. To limit ammonia slip from these systems, initial and periodic testing will be required for ammonia. Particulate matter and SOx emissions from the process heaters are based upon generally accepted emission factors; therefore, testing is not required for particulate matter and SOx emissions. The following conditions will be included on the permit:

- *Source testing to measure natural gas-combustion NOx, CO, VOC and ammonia slip emissions shall be conducted for each process heater within 60 days of startup and at least once every twelve (12) months thereafter (no more than 30 days before or after the required annual source test date). After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months (no more than 30 days before or after the required 36-month source test date). If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 2201, 4102, 4305, 4306 and 4320]*

- *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]*

- *For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 2201, 4305, 4306 and 4320]*

- *The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (lb/MMBtu) – EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4; SOx - EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content - EPA Method 11 or 15; ammonia - BAAQMD ST1B and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rules 2201, 4305, 4306, and 4320]*

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

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

Source testing is not required to verify fugitive emission rates, which are based upon generally accepted emission factors.

N-9742-21-0: Hydrogen Production Unit

The process heater is equipped with a selective catalytic reduction system to reduce NOx emissions and is equipped with an oxidation catalyst to reduce CO and VOC emissions. Initial and periodic testing of NOx, CO, and VOC will be required to ensure these controls are operating properly. Furthermore, the selective catalytic reduction system utilizes ammonia injection. To limit ammonia slip from these systems, initial and periodic testing will be required for ammonia. This unit utilizes process gas as a fuel. In addition to the below requirements, fuel sulfur content testing requirements are included in the District Rule 4320 section of this document to ensure compliance with the SOx and PM10 emission limits. The following conditions will be included on the permit:

- *Source testing to measure natural gas-combustion NOx, CO, VOC and ammonia slip emissions from the process heater shall be conducted for each process heater within 60 days of startup and at least once every twelve (12) months thereafter (no more than 30 days before or after the required annual source test date). After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months (no more than 30 days before or after the required 36-month source test date). If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 2201, 4102, 4305, 4306 and 4320]*

District Policy APR 1705 requires units equipped with a thermal oxidizer for control of VOC emissions to be tested upon initial start-up and annually thereafter, unless a District Rule specifies a different source testing frequency. Additionally, the manufacturer of the thermal oxidizer is guaranteeing a limit of 5 ppmvd NOx @ 3% O_2, a value that leaves minimal margin of compliance. Pursuant to the guidance in APR 1705,
NOx emission testing for the oxidizer will be required upon startup and annually thereafter. The following conditions will be included on the permit:

- *Source testing to measure NOx, VOC (at thermal oxidizer inlet), VOC (at thermal oxidizer outlet), and VOC control efficiency of the thermal oxidizer shall be conducted upon initial startup and annually thereafter. [District Rule 2201]*

- *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]*

- *For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 2201, 4305, 4306 and 4320]*

- *The following test methods shall be used for testing of the process heater: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (lb/MMBtu) – EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4; SOx - EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content - EPA Method 11 or 15; ammonia - BAAQMD ST1B and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rules 2201, 4305, 4306, and 4320]*

- *The following test methods shall be used for testing of the regenerative thermal oxidizer: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; VOC (ppmv or lb/MMBtu) – EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4 and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201]*

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

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

Source testing is not required to verify fugitive emission rates, which are based upon generally accepted emission factors.

<u>N-9742-22-0: Boiler</u>

The boiler is equipped with a selective catalytic reduction system to reduce NOx emissions and is equipped with an oxidation catalyst to reduce CO and VOC emissions. Initial and periodic testing of NOx, CO, and VOC will be required to ensure these controls are operating properly. Furthermore, the selective catalytic reduction system utilizes ammonia injection. To limit ammonia slip from these systems, initial and periodic testing will be required for ammonia. Particulate matter and SOx emissions from the boiler are based upon generally accepted emission factors; therefore, testing is not required for particulate matter and SOx emissions. The following conditions will be included on the permit:

- *Source testing to measure natural gas-combustion NOx, CO, VOC and ammonia slip emissions shall be conducted within 60 days of startup and at least once every twelve (12) months thereafter (no more than 30 days before or after the required annual source test date). After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months (no more than 30 days before or after the required 36-month source test date). If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 2201, 4102, 4305, 4306 and 4320]*

- *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]*

- *For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 2201, 4305, 4306 and 4320]*

- *The following test methods shall be used: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (lb/MMBtu) – EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4; SOx - EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content - EPA Method 11 or 15; ammonia - BAAQMD ST1B and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rules 2201, 4305, 4306, and 4320]*

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

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

<u>N-9742-23-0: Material Transfer Operation</u>

District Rul3 4624 requires units equipped with a control system for VOC emissions to be tested upon initial start-up and every 60 months thereafter. Additionally, the manufacturer of the thermal oxidizer is guaranteeing a limit of 5 ppmvd NOx @ 3% O_2, a value that leaves minimal margin of compliance. Therefore, initial and periodic source testing of NOx emissions will be required. The NOx testing frequency will be synchronized with the District Rule 4624 VOC testing frequency for organic liquid transfer operations. The following testing requirements will be included on the permit:

- *Source testing to measure NOx, VOC (at thermal oxidizer inlet), VOC (at thermal oxidizer outlet), and VOC control efficiency of the thermal oxidizer shall be conducted upon initial startup and every 60 months thereafter. [District Rule 2201]*

- *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]*

- *For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 2201, 4305, 4306 and 4320]*

- *The following test methods shall be used for testing of the regenerative thermal oxidizer: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; VOC (ppmv or lb/MMBtu) – EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4 and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201]*

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

Source testing is not required to verify fugitive emission rates and emissions from disconnects, since both are based upon generally accepted emission factors.

<u>N-9742-24-0: Wastewater Treatment Unit</u>

District Policy APR 1705 requires units equipped with a thermal oxidizer for control of VOC emissions to be tested upon initial start-up and annually thereafter. Additionally, the manufacturer of the thermal oxidizer is guaranteeing a limit of 5 ppmvd NOx @ 3% O_2, a value that leaves minimal margin of compliance. Pursuant to the guidance in APR 1705, NOx emission testing for the oxidizer will be required upon startup and annually thereafter. The following conditions will be included on the permit:

- *Source testing to measure NOx, VOC (at thermal oxidizer inlet), VOC (at thermal oxidizer outlet), and VOC control efficiency of the thermal oxidizer shall be conducted upon initial startup and annually thereafter. [District Rule 2201]*

- *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]*

- *For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. [District Rule 2201]*

- *The following test methods shall be used for testing of the regenerative thermal oxidizer: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; VOC (ppmv or lb/MMBtu) – EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4 and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201]*

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

Source testing is not required to verify fugitive emission rates, which are based upon generally accepted emission factors.

<u>N-9742-25-0: Cooling Tower</u>

Emissions from the cooling tower are based upon the rated recirculation rate, the manufacturer's guaranteed drift rate, and the total dissolved solids content of the water in the cooling tower, which will be monitored quarterly. The cooling tower is not conducive to source testing and testing is not required for Rule 2201 purposes.

N-9742-26-0: Emergency Flare

District Policy APR 1705 requires units equipped with a flare to control of VOC emissions to be tested upon initial start-up and annually thereafter. The following conditions will be included on the permit:

- *Source testing to measure VOC (at the flare inlet), VOC (at the flare outlet), and VOC control efficiency of the flare shall be conducted upon initial startup and annually thereafter. [District Rule 2201]*

- *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]*

- *For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. [District Rule 2201]*

- *The following test methods shall be used for testing of the flare: VOC (ppmv or lb/MMBtu) – EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4 and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201]*

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

N-9742-27-0: Emergency Firewater Pump

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

N-9742-28-0: Emergency Electrical Generator

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

N-9742-29-0: Naphtha Storage Tank #1

Source testing is not required for internal floating roof tanks to demonstrate compliance with District Rule 2201. Additionally, fugitive emissions associated with the tank are based upon generally accepted emission factors. Therefore, testing is also not required for fugitive emissions.

N-9742-30-0: Naphtha Storage Tank #2

Source testing is not required for internal floating roof tanks to demonstrate compliance with District Rule 2201. Additionally, fugitive emissions associated with the tank are based upon generally accepted emission factors. Therefore, testing is also not required for fugitive emissions.

N-9742-31-0: Slop Storage Tank #1

Source testing is not required for internal floating roof tanks to demonstrate compliance with District Rule 2201. Additionally, fugitive emissions associated with the tank are based upon generally accepted emission factors. Therefore, testing is also not required for fugitive emissions.

N-9742-32-0: Slop Storage Tank #2

Source testing is not required for internal floating roof tanks to demonstrate compliance with District Rule 2201. Additionally, fugitive emissions associated with the tank are based upon generally accepted emission factors. Therefore, testing is also not required for fugitive emissions.

2. Monitoring

N-9742-20-0: HydroFlex Fuel Production Unit

Each of the process heaters is subject to the monitoring requirements of District Rules 4305, 4306, and 4320. The monitoring requirements for the process heaters will be discussed in the District Rule 4320 section of this document.

The HydroFlex production unit fugitive components are subject to the requirements of District Rule 4455. The monitoring requirements for the fugitive components will be discussed in the District Rule 4455 section of this document.

N-9742-21-0: Hydrogen Production Unit

The process heater is subject to the monitoring requirements of District Rules 4305, 4306, and 4320. The monitoring requirements for the process heater will be discussed in the District Rule 4320 section of this document.

The hydrogen production unit fugitive components are subject to the requirements of District Rule 4455. The monitoring requirements for the fugitive components will be discussed in the District Rule 4455 section of this document.

The regenerative thermal oxidizer must maintain a temperature of 1400 degrees Fahrenheit and 0.5 seconds of retention time in order to meet the guaranteed control efficiency. The following conditions will be included on the permit to monitor the temperature in the thermal oxidizer combustion chamber.

- *The regenerative thermal oxidizer shall be operated with a combustion chamber temperature of no less than 1400 degrees F and the retention time shall be no less than 0.5 seconds. A continuous temperature monitoring and recording device shall be used and kept in good working order. [District Rule 2201]*

- *The regenerative thermal oxidizer shall be heated to proper operating temperature prior to any process air entering the oxidizer. [District Rule 2201]*

Additionally, the sulfur content to the RTO will be required to be monitored annually. The following conditions will be included on the permit:

- *The permittee shall determine the sulfur content of process gas combusted in the thermal oxidizer annually and shall maintain records of the fuel sulfur content. [District Rules 1081 and 2201]*

<u>N-9742-22-0: Boiler</u>

The boiler is subject to the monitoring requirements of District Rules 4305, 4306, and 4320. The monitoring requirements for the boiler will be discussed in the District Rule 4320 section of this document.

<u>N-9742-23-0: Material Transfer Operation</u>

The regenerative thermal oxidizer must maintain a temperature of 1400 degrees Fahrenheit and 0.5 seconds of retention time in order to meet the guaranteed control efficiency. The following conditions will be included on the permit to monitor the temperature in the thermal oxidizer combustion chamber.

- *The regenerative thermal oxidizer shall be operated with a combustion chamber temperature of no less than 1400 degrees F and the retention time shall be no less than 0.5 seconds. A continuous temperature monitoring and recording device shall be used and kept in good working order. [District Rule 2201]*

- *The regenerative thermal oxidizer shall be heated to proper operating temperature prior to any process air entering the oxidizer. [District Rule 2201]*

Additionally, the sulfur content to the RTO will be required to be monitored annually. The following conditions will be included on the permit:

- *The permittee shall determine the sulfur content of process gas combusted in the thermal oxidizer annually and shall maintain records of the fuel sulfur content. [District Rules 1081 and 2201]*

N-9742-24-0: Wastewater Treatment Unit

The wastewater treatment unit fugitive components are subject to the requirements of District Rule 4455. The monitoring requirements for the fugitive components will be discussed in the District Rule 4455 section of this document.

The regenerative thermal oxidizer must maintain a temperature of 1400 degrees Fahrenheit and 0.5 seconds of retention time in order to meet the guaranteed control efficiency. The following conditions will be included on the permit to monitor the temperature in the thermal oxidizer combustion chamber.

- *The regenerative thermal oxidizer shall be operated with a combustion chamber temperature of no less than 1400 degrees F and the retention time shall be no less than 0.5 seconds. A continuous temperature monitoring and recording device shall be used and kept in good working order. [District Rule 2201]*

- *The regenerative thermal oxidizer shall be heated to proper operating temperature prior to any process air entering the oxidizer. [District Rule 2201]*

Additionally, the sulfur content to the RTO will be required to be monitored annually. The following conditions will be included on the permit:

- *The permittee shall determine the sulfur content of process gas combusted in the thermal oxidizer annually and shall maintain records of the fuel sulfur content. [District Rules 1081 and 2201]*

N-9742-25-0: Cooling Tower

Quarterly monitoring of the cooling tower total dissolved solids concentration will be required in order to monitor particulate matter emissions from the cooling tower. The following conditions will be included on the permit:

- *Total Dissolved Solids (TDS) in the blowdown water shall be sampled and analyzed using a conductivity analyzer at least quarterly. [District Rule 2201]*

N-9742-26-0: Emergency Flare

The flare is subject to the requirements of District Rule 4311. The monitoring requirements for the flare will be discussed in the District Rule 4311 section of this document.

N-9742-27-0: Emergency Firewater Pump

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

N-9742-28-0: Emergency Electrical Generator

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

N-9742-29-0: Naphtha Storage Tank #1

The tank is subject to the requirements of District Rule 4623. Monitoring requirements for the tank will be discussed in the District Rule 4623 section of this document.

N-9742-30-0: Naphtha Storage Tank #2

The tank is subject to the requirements of District Rule 4623. Monitoring requirements for the tank will be discussed in the District Rule 4623 section of this document.

N-9742-31-0: Slop Storage Tank #1

The tank is subject to the requirements of District Rule 4623. Monitoring requirements for the tank will be discussed in the District Rule 4623 section of this document.

N-9742-32-0: Slop Storage Tank #2

The tank is subject to the requirements of District Rule 4623. Monitoring requirements for the tank will be discussed in the District Rule 4623 section of this document.

3. Recordkeeping

N-9742-20-0: HydroFlex Fuel Production Unit

The following recordkeeping requirements will be included on the permit:

- *For each process heater, the permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements using a portable analyzer, (2) the O2 concentration in percent by volume and the measured NOx, CO, and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 2201, 4305, 4306 and 4320]*

- *For each process heater, the permittee shall determine the sulfur content of combusted gas annually and shall maintain records of the fuel sulfur content or shall maintain records of fuel purchase contracts, supplier certifications, tariff sheets, or transportation contracts demonstrating that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320]*

- *For each process heater, the owner or operator shall maintain records of the date, duration of each startup and shutdown event (hour/event), total duration of startup and shutdown time (hours/day), and total duration of startup and shutdown time per year (hours/year). The annual records shall be updated at least on a monthly basis. [District Rules 2201, 4306, and 4320]*

- *The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]*

- *All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320]*

<u>N-9742-21-0: Hydrogen Production Unit</u>

The following recordkeeping requirements will be included on the permit:

- *For the process heater, the permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements using a portable analyzer, (2) the O2 concentration in percent by volume and the measured NOx, CO, and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 2201, 4305, 4306 and 4320]*

- *For the process heater, the permittee shall determine the sulfur content of combusted gas annually and shall maintain records of the fuel sulfur content or shall maintain records of fuel purchase contracts, supplier certifications, tariff sheets, or transportation contracts demonstrating that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320]*

- *For the process heater, the owner or operator shall maintain records of the date, duration of each startup and shutdown event (hour/event), total duration of startup and shutdown time (hours/day), and total duration of startup and shutdown time per year (hours/year). The annual records shall be updated at least on a monthly basis. t [District Rules 2201, 4306, and 4320]*

- *The permittee shall keep a record of the regenerative thermal oxidizer temperature readings collected from the data recorder on a daily basis. [District Rule 2201]*

- *The permittee shall keep a record of the quantity of process gas (in MMBtu) processed each day and a record of the cumulative quantity of process gas (in MMBtu) processed in each rolling 12-month period. [District Rule 2201]*

- *The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]*

- *All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320]*

N-9742-22-0: Boiler

- *The permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements using a portable analyzer, (2) the O2 concentration in percent by volume and the measured NOx, CO, and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 2201, 4305, 4306 and 4320]*

- *The permittee shall determine the sulfur content of combusted gas annually and shall maintain records of the fuel sulfur content or shall maintain records of fuel purchase contracts, supplier certifications, tariff sheets, or transportation contracts demonstrating that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320]*

- *The owner or operator shall maintain records of the date, duration of each startup and shutdown event (hour/event), total duration of startup and shutdown time (hours/day), and total duration of startup and shutdown time per year (hours/year). The annual records shall be updated at least on a monthly basis. [District Rules 2201, 4306, and 4320]*

- *All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320, and 40 CFR 60.48c(i)]*

N-9742-23-0: Material Transfer Operation

- *The permittee shall keep a record of the regenerative thermal oxidizer temperature readings collected from the data recorder on a daily basis. [District Rule 2201]*

- *The permittee shall keep a record of the quantity of process gas (in MMBtu) processed each day and a record of the cumulative quantity of process gas (in MMBtu) processed in each rolling 12-month period. [District Rule 2201]*

- *The permittee shall keep a record of the quantity of disconnects in each day and on a rolling 12-month basis for the following; 1) the transfer of feedstocks; 2) the transfer renewable diesel and sustainable aviation fuel; and 3) for the transfer of naphtha. [District Rule 2201]*

- *The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]*

- *All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320, and 40 CFR 60.48c(i)]*

<u>N-9742-24-0: Wastewater Treatment Unit</u>

- *The permittee shall keep a record of the regenerative thermal oxidizer temperature readings collected from the data recorder on a daily basis. [District Rule 2201]*

- *The permittee shall keep a record of the quantity of process gas (in MMBtu) processed each day and a record of the cumulative quantity of process gas (in MMBtu) processed in each rolling 12-month period. [District Rule 2201]*

- *The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]*

- *All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201]*

<u>N-9742-25-0: Cooling Tower</u>

- *The operator shall maintain records of all circulating water tests performed. Records shall be maintained for at least 5 years and shall be made available to the District upon request. [District Rule 2201]*

<u>N-9742-26-0: Emergency Flare</u>

- *The operator shall keep a record of the daily heat input to the flare and shall keep a record of the cumulative rolling 12-month heat input to the flare. [District Rule 2201]*

- *All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201]*

N-9742-27-0: Emergency Firewater Pump

Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, District Rule 4702, of this evaluation.

N-9742-28-0: Emergency Electrical Generator

Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, District Rule 4702, of this evaluation.

N-9742-29-0: Naphtha Storage Tank #1

Recordkeeping requirements, in accordance with District Rule 4623, will be discussed in Section VIII, District Rule 4623, of this evaluation.

N-9742-30-0: Naphtha Storage Tank #2

Recordkeeping requirements, in accordance with District Rule 4623, will be discussed in Section VIII, District Rule 4623, of this evaluation.

N-9742-31-0: Slop Storage Tank #1

Recordkeeping requirements, in accordance with District Rule 4623, will be discussed in Section VIII, District Rule 4623, of this evaluation.

N-9742-32-0: Slop Storage Tank #2

Recordkeeping requirements, in accordance with District Rule 4623, will be discussed in Section VIII, District Rule 4623, of this evaluation.

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

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 H 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 $PM_{2.5}$.

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

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

Rule 4001 New Source Performance Standards (NSPS)

40 CFR 60 Subpart Db: Standards of Performance for Industrial-Commercial- Steam Generating Units

This regulation is applicable to steam generating units that commence construction after June 19, 1984 and that has a heat input from combusted fuels greater than 100 MMBtu/hr. The process heater associated with the hydrogen production unit is the only unit potentially subject to the requirements of this regulation.

According to the definition of "Steam generating unit" in this regulation, process heaters as defined in this regulation are not steam generating units. A process heater *means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.* The process heater associated with the hydrogen production unit heats material to promote a chemical reaction. Therefore, it meets the definition of process heater in this regulation and is not a steam generating unit. Subpart Db requirements are not applicable to the process heater associated with the hydrogen production unit.

40 CFR 60 Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

This regulation is applicable to each steam generating unit for which construction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than 10 MMBtu/hr. The three process heaters associated with the HydroFlex production unit and the auxiliary boiler are potentially subject to the requirements of this regulation.

According to the definition of "Steam generating unit" in this regulation, process heaters as defined in this regulation are not steam generating units. A process heater *means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.* The three process heaters associated with the HydroFlex production unit each heats material to promote a chemical reaction.

Therefore, the three process heaters meets the definition of process heater in this regulation and are each not a steam generating unit. Subpart Db requirements are not applicable to the process heaters associated with the HydroFlex production unit.

The auxiliary boiler is a steam generating unit and is subject to the requirements of this regulation. The following discussion only applies to the auxiliary boiler.

§60.42c Standard for sulfur dioxide (SO_2)

This section lists SO_2 standards for steam generating units fired on coal, coal combusted with other fuels, oil, and oil combusted with other fuels. This unit is only fired on PUC quality natural gas; therefore, it is not subject to the standards in this section.

§60.43c Standard for particulate matter (PM)

This section lists PM standards for steam generating units fired on coal, coal with other fuels, wood, wood with other fuels, and oil. This unit is only fired on PUC quality natural gas; therefore, it is not subject to the standards in this section.

§60.44c Compliance and performance test methods and procedures for sulfur dioxide

This section lists compliance and performance standards to demonstrate compliance with the sulfur dioxide standards of this regulation. Since the auxiliary boiler is not subject to the sulfur dioxide standard of the regulation, source testing is not necessary to demonstrate compliance.

§60.45c Compliance and performance test methods and procedures for particulate matter

This section lists compliance and performance standards to demonstrate compliance with the particulate matter standards of this regulation. Since the auxiliary boiler is not subject to the particulate matter standard of the regulation, source testing is not necessary to demonstrate compliance.

§60.46c Emission Monitoring for sulfur dioxide

This section lists monitoring requirements to demonstrate ongoing compliance with the sulfur dioxide standards of this regulation. Since the auxiliary boiler is not subject to the sulfur dioxide standard of this regulation, monitoring is not necessary to demonstrate compliance.

§60.47c Emission Monitoring for particulate matter

This section lists monitoring requirements to demonstrate ongoing compliance with the particulate matter standards of this regulation. Since the auxiliary boiler is not subject to the particulate matter standard of this regulation, monitoring is not necessary to demonstrate compliance.

§60.48c Reporting and recordkeeping requirements

Section 60.48c(a) requires the owner or operator of each affected facility to submit notification of the date of construction or reconstruction and actual startup, as provided by Section 60. Of this part. This notification must include:

1. The design heat input capacity and identification of fuels to be combusted in the affected facility.
2. If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel, or mixture of fuels.
3. The annual capacity at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.
4. Notification if any emerging technology will be used for controlling SO_2 emissions.

The heat input capacity and identification of fuels to be combusted are already included in the draft permit. Additionally, the capacity factor and federally enforceable requirements have already been provided to the District. Finally, no emerging technologies will be utilized to reduce SO_2 emissions from the boiler. Thus, the notification requirements have already been satisfied.

Section 60.48c(b) applies to units subject to the SO_2 requirements of this regulation. Since the auxiliary boiler is not subject to the SO_2 requirements, this section is not applicable.

Section 6048c(c) requires the owner or operator of an affected facility subject to the opacity limits of this regulation to submit excess emission reports for any excess emissions. Since the auxiliary boiler is not subject to the opacity limits of this regulation, this section is not applicable.

Section 60.48c(d) requires the owner or operator of units subject to the SO_2 emission limits to submit reports to the administrator. Since the auxiliary boiler is not subject to the SO_2 requirements, this section is not applicable.

Section 60.48c(e) lists recordkeeping and reporting requirements for units subject to the SO_2 standards of this subpart. Since the auxiliary boiler is not subject to the SO_2 standard of this subpart, this section is not applicable.

Section 60.48c(f) lists fuel supplier certification requirements for units fired on distillate oil, residual oil, coal, and other fuels listed in the regulation. The auxiliary fuel is fired on PUC-quality natural gas for which the sulfur content is regulated and known. Thus, a fuel supplier certification is not necessary.
Section 60.48c(g)(1), (2), and (3) requires the owner or operator of a unit fired solely on natural gas to keep and maintain a record of the amount of each fuel combusted during each month. The following condition will be included on permit N-9742-22 for the auxiliary boiler:

- *The owner or operator shall maintain records of the amount of fuel combusted during each calendar month in this unit. [40 CFR 60.48c(g)]*

Section 60.48c(h) is only applicable to units with a federally enforceable requirement limiting the annual capacity. This section is not applicable to the auxiliary boiler.

Section 60.48c(i) states that records must be maintained by the owner for a period of at least two years. The following condition will be included on permit N-9742-22 for the auxiliary boiler:

- *All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320, and 40 CFR 60.48c(i)]*

Compliance with the requirements of this regulation is expected.

40 CFR 60 Subpart Kb: Standards of Performance for Volatile Organic Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

The requirements of this subpart are applicable to each storage vessel with a capacity greater than 75 cubic meters (19,812 gallons) that is used to store volatile organic liquids, constructed after July 23, 1984. The naphtha storage tanks (N-9742-29 and '-30) and the slop storage tanks (N-9742-31 and '-32) are subject to the requirements of this Subpart.

§60.112b Standard for Volatile Organic Compounds

Section 60.112b(a) states that the owner or operator of each storage vessel with a design capacity greater than 151 cubic meters (39,890 gallons) that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPA (0.75 psia) but less than 76.6 kPa (11.1 psia) to meet one of the following:

1. Use an internal floating roof storage tank.
2. Use an external floating roof tank
3. Use a tank with a closed vent system and control device

Each of the proposed naphtha tanks utilizes an internal floating roof and stores liquid with a vapor pressure between 0.75 psia and 11.1 psia. The slop in the slop tanks has a vapor pressure lower than 0.75 psia. Therefore, the slop tanks are not subject to the requirements of this regulation.

The following requirements are applicable to tanks storing naphtha (N-9742-29 and '-30):

Section 60.112b(a)(1)(i) requires that the internal floating roof rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof must be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible. The following condition will be included on each of the naphtha storage tank permits:

- *The internal floating roof shall be floating on the surface of the stored liquid at all times (i.e., off the roof leg supports) except during the initial fill until the roof is lifted off the leg supports and when the tank is completely emptied and subsequently refilled, and for tank interior cleaning, and during tank repair and maintenance activities. When the roof is resting on the leg supports the processes of filling or emptying and refilling shall be continuous and shall be accomplished as rapidly as possible. Whenever the permittee intends to land the roof on its legs, the permittee shall notify the APCO in writing at least five calendar days prior to performing the work. The tank must be in compliance with this rule before it may land the roof on its legs. [District Rules 2020, 2201, and 4623, and 40 CFR 60.112b(a)(1)(i)]*

Section 60.112b(a)(1)(ii)(C) states that each internal floating roof shall be equipped with a mechanical shoe seal. The mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coating fabric (envelope) spans the annular space between the metal sheet and the floating roof. The use of a mechanical shoe seal has been included in the equipment description for the proposed naphtha tanks.

Section 60.112b(a)(1)(iii) states that each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface. The following condition will be included on each of the naphtha storage tank permits:

- *Each opening in a non-contact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents shall provide a projection below the liquid surface. [District Rule 4623 and 40 CFR 60.112b(a)(1)(iii)]*

Section 60.112b(a)(1)(iv) states that each opening in the internal floating roof, except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains, is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid must be equipped with a gasket. Covers on each access hatch and the automatic gauge float well must be bolted except when they are actually in used. The following condition will be included on each naphtha storage tank permit:

- *Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains shall be equipped with a cover, or a lid shall be maintained in a closed position at all times (i.e. no visible gaps) except when the device is in use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted in place except when they are in use. [District Rule 4623 and 40 CFR 60.112b(a)(1)(iv)]*

Section 60.112b(a)(1)(v) states that the automatic bleeder vents must be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. The following condition will be included on each of the naphtha storage tank permits:

- *Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the leg roof supports. [District Rule 4623 and 40 CFR 60.112b(a)(1)(v)]*

Section 60.112b(a)(1)(vi) states that the rim space vents must be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. The following condition will be included on each of the naphtha storage tank permits:

- *Rim vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. [District Rule 4623 and 40 CFR 60.112b(a)(1)(vi)]*

Section 60.112b(a)(1)(vii) states that each penetration of the internal floating roof for the purpose of sampling must be a sample well. The sample well must have a slit fabric cover that covers at least 90 percent of the opening. The following condition will be included on each of the naphtha storage tank permits:

- *Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90 percent of the opening. The fabric cover must be impermeable. [District Rule 4623 and 40 CFR 60.112b(a)(1)(vii)]*

Section 60.112b(a)(1)(viii) states that each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof must have a flexible fabric sleeve seal or gasketed sliding cover. The following condition will be included on each of the naphtha storage tank permits:

- *Each penetration of the internal floating roof that allows for the passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable. [District Rule 4623 and 40 CFR 60.112b(a)(1)(viii)]*

Section 60.112b(a)(1)(ix) states that each penetration of the internal floating roof that allows for the passage of a ladder must have a gasketed sliding cover. The following condition will be included on each of the naphtha storage tank permits:

- *Each penetration of the internal floating roof that allows for the passage of a ladder shall have a gasketed sliding cover. [40 CFR 60.112b(a)(1)(ix)]*

Section 60.113b(a)(1) states that the owner or operator must visually inspect the internal floating roof, primary seal, and the secondary seal prior to filling the tank with volatile organic liquids. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric, or defects in the internal floating roof, or both, the owner or operator must repair the items before filling the storage vessel. The following condition will be included on each of the naphtha storage tank permits:

- *For newly constructed, repaired, or rebuilt internal floating roof tanks, the permittee shall visually inspect the internal floating roof, and its appurtenant parts, fittings, etc. and measure the gaps of the primary seal and/or secondary seal prior to filling the tank for newly constructed, repair, or rebuilt internal floating roof tanks. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to filling the tank. [District Rule 4623 and 40 CFR 60.113b(a)(1)]*

Section 60.113b(a)(2) states that for vessels equipped with a liquid-mounted or mechanical shoe primary seal, the owner or operator must visually inspect the internal floating roof and the primary seal or the secondary seal through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the volatile organic liquid inside the storage tank, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator must repair the items or empty and remove the tank from service within 45 days. If a failure is detected during the inspections that cannot be repaired within 45 days and if the tank cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator. Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure the control equipment will be repaired or the vessel will be emptied as soon as possible. The following conditions will be included on each of the naphtha storage tank permits:

- *The operator shall visually inspect, through the manholes, roof hatches, or other opening on the fixed roof, the internal floating roof and its appurtenant parts, fittings, etc., and the primary seal and/or secondary seal at least once every 12 months after the tank is initially filled with an organic liquid. There should be no visible organic liquid on the roof, tank walls, or anywhere. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of vapors. Any defects found are violations of this rule. [District Rule 4623 and 40 CFR 60.113b(a)(2)]*

- *If any failure (i.e. visible organic liquid on the internal floating roof, tank walls or anywhere, holes or tears in the seal fabric) is detected during 12 month visual inspection, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If the detected failure cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the APCO in the inspection report. Such a request must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible. [40 CFR 60.113b(a)(2)]*

Section 60.113b(a)(3) is applicable to units equipped with a double-seal system. These tanks are not equipped with this type of system; therefore, this section is not applicable.

Section 60.113b(a)(4) states that the owner or operator must visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes and sleeve seals each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator must repair the items as necessary so that none of the conditions listed exist before refilling the storage vessel with volatile organic liquids. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years. The following condition will be included on each of the naphtha storage tank permits:

- *The operator shall visually inspect the internal floating roof, the primary seal and/or secondary seal, gaskets, slotted membrane and/or sleeve seals each time the storage tank is emptied and degassed. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to refilling the tank. [40 CFR 60.113b(a)(4)]*

Section 60.113b(a)(5) states that the owner or operator must notify the Administrator in writing at least 30 days prior to the filling or refilling of each tank for which an inspection is required to afford the Administrator the opportunity to have an observer present. If the visual inspection is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator must notify the Administrator at least 7 days prior to the refilling of the tank. Notification shall be made by telephone immediately followed by written documentation demonstrating why the visual inspection was unplanned. Alternatively, this notification, including the written documentation, may be made in writing and sent by express mail such that it is received by the Administrator at least 7 days prior to refilling the tank. The following condition will be included on each of the naphtha storage tank permits:

- *The permittee shall notify the District in writing at least 30 days prior to conduct the visual inspection of the storage vessel, so the District can arrange an observer. [40 CFR 60.113b(a)(5)]*

Section 60.115b(a) states that the following records must be kept and maintained for a fixed roof and internal floating roof:

1. Furnish the Administrator with a report that describes the control equipment and certifies the control equipment meets the specifications listed earlier.
2. Keep a record of each inspection performed. Each record must identify the tank on which the inspection was performed and must contain the date the tank was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings)

3. If any of the conditions described in 60.113b(a)(2) are detected during the annual visual inspection required, a report must be furnished to the Administrator within 30 days of the inspection. Each report must identify the tank, the nature of the defects, and the date the repair was made.
4. After each inspection required in 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, a report must be furnished to the Administrator within 30 days of the inspection. The report must identify the tank and the reason it did not meet the specifications and list each repair made.

The following conditions will be included on each of the naphtha storage tank permits:

- *The permittee shall furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specification of 40 CFR Part 60.112b(a)(1) and 40 CFR Part 60.113b(a)(1) within 15 days after the initial startup of the equipment. [40 CFR 60.115b(a)(1)]*

- *The permittee shall submit the reports of the floating roof tank inspections to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Rule 4623, Sections 5.2 through 5.5. The inspection report for tanks that that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and made available upon request by the APCO. The inspection report shall contain all necessary information to demonstrate compliance with the provisions of this rule, including the following: 1) Date the storage vessel was emptied, date of inspection and names and titles of company personnel doing the inspection. 2) Tank identification number and Permit to Operate number. 3) Observed condition of each component of the control equipment (seals, internal floating roof, and fittings). 4) Measurements of the gaps between the tank shell and primary and secondary seals. 5) Leak free status of the tank and floating roof deck fittings. Records of the leak-free status shall include the vapor concentration values measured in parts per million by volume (ppmv). 6) Data, supported by calculations, demonstrating compliance with the requirements specified in Sections 5.4 and 5.5.2.4.3 of Rule 4623. 7) Nature of defects and any corrective actions or repairs performed on the tank in order to comply with rule 4623 and the date(s) such actions were taken. [District Rule 4623 and 40 CFR 60.115b(a)]*

Section 60.116b(a) states that records must be kept for 2 years. The District requires records to be kept for a minimum of five years. The following condition will be included on each of the naphtha storage tanks:

- *All records shall be maintained on site for a period of at least five years and shall be made available for District, ARB, and EPA inspection upon request. [District Rules 1070, 2201 and 4623, and 40 CFR 60.116b(a)]*

Section 60.116b(b) requires the owner or operator of each tank to keep a record of each tank to keep readily accessible records (for the life of the source) showing the dimensions of the tank and analysis showing the capacity of the tank. The following condition will be included on each of the naphtha storage tank permits:

- *The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel, and these records shall be kept for the life of the source. [40 CFR 60.116b(b)]*

Section 60.116b(c) requires the owner or operator to maintain a record of the volatile organic liquid stored, the period of storage, and the maximum true vapor pressure of that volatile organic liquid during the storage period. The following condition will be included on each of the naphtha storage tank permits:

- *The permittee shall maintain records of the volatile organic liquid stored, the period of storage, and TVP of that volatile organic liquid during the respective storage period. TVP shall be determined using the data on the reid vapor pressure (highest receipt or highest tank sample results) and actual storage temperature. [District Rule 2201 and 40 CFR 60.116b(c)]*

Section 60.116(b)(e)(3) states that the true vapor pressure may:

1. May be obtained from standard reference texts; or
2. Determined by ASTM D2879-83, 96, or 97; or
3. Measured by an appropriate method approved by the Administrator; or
4. Calculated by an appropriate method approved by the Administrator.

The following condition will be included on each of the naphtha storage tank permits:

- *The owner or operator shall determine the vapor pressure of the stored organic liquid by: 1)using a standard reference text; or 2) Testing using ASTM D2879-83, 96 or 97; or 3) measuring the vapor pressure using an appropriate method approved by the District; or 4) Calculating the vapor pressure using an appropriate method approved by the District. [40 CFR 60.116(b)(e)(3)]*

Compliance with the requirements of Subpart Kb is expected.

<u>40 CFR 60 Subpart VVa: Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006</u>

The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry. The group of all equipment (defined in §60.481a) within a process unit is an affected facility.

A synthetic organic chemical manufacturing industry means the industry that produces, as intermediates or final products, one or more the chemicals in §60.489. Neither of the products, renewable diesel fuel and sustainable aviation fuel, are listed in the chemicals in §60.489. Intermediates produced in the reaction processes at this plant are hydrogen,

hydrogen sulfide, naphtha, ammonia and methane. None of these chemicals is listed in §60.489; therefore, the proposed plant does not meet the definition of a synthetic organic chemicals manufacturing industry and the requirements of this Subpart are not applicable.

40 CFR 60 Subpart III: Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Processes

This subpart defines an "Air Oxidation Reactor" as any device or process vessel in which one or more organic reactants are combined with air or a combination of air and oxygen, to produce one or more organic compounds". Neither the HydroFlex unit nor the hydrogen production unit uses an air oxidation reactor in their process. Thus, the requirements of this Subpart are not applicable to the units in this project.

40 CFR 60 Subpart NNN: Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations

This subpart is applicable to each affected facility that is part of a process unit that produces any of the chemicals in §60.667 as a product, co-product, by-product, or intermediate.

Neither of the products, renewable diesel fuel and sustainable aviation fuel, are listed in the chemicals in §60.667. Intermediates produced in the reaction processes at this plant are hydrogen, hydrogen sulfide, naphtha, ammonia and methane. None of these chemicals is listed in §60.667; therefore, the proposed processes are not subject to the requirements of this subpart.

40 CFR 60 Subpart RRR: Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

This subpart is applicable to each affected facility that is part of a process unit that produces any of the chemicals in §60.707 as a product, co-product, by-product, or intermediate.

Neither of the products, renewable diesel fuel and sustainable aviation fuel, are listed in the chemicals in §60.707. Intermediates produced in the reaction processes at this plant are hydrogen, hydrogen sulfide, naphtha, ammonia and methane. None of these chemicals is listed in §60.707; therefore, the proposed processes are not subject to the requirements of this subpart.

40 CFR 60 Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The District has not been delegated the authority to implement Subpart IIII requirements for non-Major Sources; therefore, no requirements shall be included on the permit.

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

40 CFR 63 Subpart F: National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry

Pursuant to the applicability section, Subpart F is only applicable to plants located at a Major Source of HAP emissions. Pursuant to the HAP calculations in Appendix F, this is not a Major Source of HAP emissions; therefore, Subpart F is not applicable to any of the units in this project.

40 CFR 63 Subpart G: National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater

Pursuant to the applicability section, Subpart G is only applicable to process vents, storage vessels, transfer racks, wastewater streams and in-process equipment that are within a source subject to Subpart F. Since this facility is not subject to Subpart F requirements, Subpart G requirements are not applicable to any of the units in this project.

40 CFR 63 Subpart H: National Emission Standards for Hazardous Air Pollutants for Equipment Leaks

The provisions of this Subpart only apply if a source is subject to the provisions of a specific Subpart in 40 CR Part 63 that references Subpart H requirements. The proposed units at this facility are not subject to any Subparts of 40 CFR Part 63 that reference Subpart H requirements; therefore, Subpart H requirements are not applicable to any of the units in this project.

40 CFR 63 Subpart Q: National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers

The provisions of this regulation apply to all new and existing industrial process cooling towers that are operated with chromium based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources of HAPs. This facility is not a Major Source of HAPs and the cooling tower is not operated with chromium based water treatment chemicals. Therefore, the requirements of this subpart are not applicable.

40 CFR 63 Subpart OO: National Emission Standards for Tanks – Level 1

The provisions of Subpart OO only apply if a source is subject to the provisions of another subpart of 40 CFR 63 that references the use of Subpart OO requirements. Since none of the proposed equipment is subject to a Subpart of 40 CFR 63 that references Subpart OO, the requirements of Subpart OO are not applicable to any of the units in this project.

40 CFR 63 Subpart TT: National Emission Standards for Equipment Leaks – Control Level 1

The provisions of Subpart TT only apply if a source is subject to the provisions of another subpart of 40 CFR 63 that references the use of Subpart TT requirements. Since none of the proposed equipment is subject to a Subpart of 40 CFR 63 that references Subpart TT, the requirements of Subpart TT are not applicable to any of the units in this project.

40 CFR 63 Subpart UU: National Emission Standards for Equipment Leaks – Control Level 2 Standards

The provisions of Subpart UU only apply if a source is subject to the provisions of another subpart of 40 CFR 63 that references the use of Subpart UU requirements. Since none of the proposed equipment is subject to a Subpart of 40 CFR 63 that references Subpart UU, the requirements of Subpart UU are not applicable to any of the units in this project.

40 CFR 63 Subpart WW: National Emission Standards for Tanks – Control Level 2

The provisions of Subpart WW only apply if a source is subject to the provisions of another subpart of 40 CFR 63 that references the use of Subpart WW requirements. Since none of the proposed equipment is subject to a Subpart of 40 CFR 63 that references Subpart WW, the requirements of Subpart WW are not applicable to any of the units in this project.

40 CFR 60 Subpart EEEE: National Emission Standards for Hazardous Air Pollutants – Organic Liquids Distribution (Non-Gasoline)

Pursuant to the applicability section, Subpart EEEE is only applicable to plants located at a Major Source of HAP emissions. Pursuant to the HAP calculations in Appendix F, this is not a Major Source of HAP emissions; therefore, Subpart EEEE is not applicable to any of the units in this project.

40 CFR 60 Subpart FFFF: National Emission Standards for Hazardous Air Pollutants – Miscellaneous Organic Chemical Manufacturing

Pursuant to the applicability section, Subpart FFFF is only applicable to plants located at a Major Source of HAP emissions. Pursuant to the HAP calculations in Appendix F, this is not a Major Source of HAP emissions; therefore, Subpart FFFF is not applicable to any of the units in this project.

40 CFR 63 Subpart VVVVVV: National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources

Pursuant to the applicability section, a facility is subject to this subpart if they own or operate a chemical manufacturing process unit (CMPU) that meets the conditions below:

1. The CMPU is located at an area source of hazardous air pollutant (HAP) emissions.

The proposed facility is an area source of hazardous air emissions.

2. HAP listed in Table 1 to this subpart are present in the CMPU as follows:

    a. The CMPU uses a feedstock, any material that contains quinolone, manganese, and/or trivalent chromium at an individual concentration greater than 1.0 percent by weight, or any other Table 1 HAP (1,3-butadiene, 1,3-dichloropropene, acetaldehyde, chloroform, ethylene dichloride, hexachlorobenzene, methylene chloride, arsenic compounds, chromium compounds, lead compounds, manganese compounds, and nickel compounds) at an individual concentration greater than 0.1 percent by weight.

    The proposed feedstocks (beef tallow and vegetable oil) do not contain the above HAPs in concentrations greater than the thresholds listed.

    b. Quinolone is generated as byproduct and is present in the CMPU in any liquid stream (process or waste) at a concentration greater than 1.0 percent by weight.

    Quinolone will not be present in the CMPU in any liquid stream (process or waste) at a concentrate greater than 1.0 percent by weight.

    c. Hydrazine and/or Table 1 HAP (see list above in a.) other than quinolone are generated as byproduct and are present in the CMPU in any liquid stream (process or waste), continuous process vent, or batch process vent at an individual concentration greater than 0.1 percent by weight.

    The process does not include any byproducts listed above at an individual concentration greater than 0.1 percent by weight.

    Since the process does not meet any of the thresholds listed in #2 above, Subpart VVVVVV requirements are not applicable.

<u>40 CFR 63 Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Major Sources – Industrial, Commercial, and Institutional Boilers and Process Heaters</u>

This regulation is applicable to boilers and process heaters located at Major Source of HAP emissions. As shown in Appendix F, this facility is not a Major Source of HAP emissions; therefore, the requirements of this Subpart are not applicable to the units in this project.

<u>40 CFR 63 Subpart JJJJJJ: National Emission Standards for Industrial, Commercial and Institutional Boilers Area Sources</u>

Pursuant to Section 63.11195(e), gas fired boilers are not subject to the requirements of this Subpart. Since all of the process heaters and boilers in this project are gas fired, the requirements of this Subpart do not apply to the units in this project.

Rule 4101 Visible Emissions

Section 5.0, indicates 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 dark or darker than Ringelmann 1 or equivalent to 20% opacity. The following condition will be included on each permit:

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

Rule 4102 Nuisance

Rule 4102 states that no air contaminant shall be released into the atmosphere that causes a public nuisance. Public nuisance conditions are not expected as a result of these operations provided the equipment is well maintained. Therefore, the following condition will be listed on each permit to ensure compliance:

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

California Health & Safety Code 41700 (Health Risk Assessment)

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

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 (see Appendix H), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The resulting prioritization score, acute hazard index, chronic hazard index, and cancer risk for this project is shown below.

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
20-0	1.93	0.05	0.01	2.06E-06	Yes	Yes
21-0	2.58	0.08	0.02	3.55E-06	Yes	Yes
22-0	0.17	0.00	0.00	2.10E-08	No	Yes
23-0	0.20	0.00	0.00	9.78E-07	No	Yes
24-0	0.19	0.00	0.00	1.25E-09	No	Yes
25-0	N/A[1]	N/A[1]	N/A[1]	N/A[1]	No	No
26-0	0.77	0.03	0.00	1.25E-07	No	Yes
27-0	3.81	0.00	N/A[2]	7.76E-07	No	Yes
28-0	1.88	0.00	N/A[2]	2.03E-08	No	Yes
29-0	0.68	0.00	0.00	1.74E-07	No	No
30-0	0.51	0.00	0.00	1.38E-07	No	No
31-0	0.01	0.00	0.00	2.36E-09	No	No
32-0	0.01	0.00	0.00	2.80E-09	No	No
Project Totals	12.60	0.16	0.03	7.07E-06		
Facility Totals	>1	0.18	0.14	1.01E-05		

Notes:

1. Cancer risk, acute and chronic hazard indices were not calculated for Unit 25 since there is no risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.
2. Acute hazard index was not calculated for Unit 7 & 28 since there is no risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

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 required for this project because the HRA indicates that the risk is above the District's thresholds for triggering T-BACT requirements.

For this project T-BACT is triggered VOC emissions (benzene) from the fugitive components associated with the HydroFlex production unit (N-9742-20) and from the fugitive components associated with the hydrogen production unit (N-9742-21). T-BACT is satisfied with BACT for VOC (see Appendix E.3), which is leaks defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 and Maintenance Program pursuant to District Rule 4455. 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 Attachment H: Health Risk Assessment Summary

The following permit conditions are required to ensure compliance with the assumptions made for the risk management review:

Units # 25-0, 29-0, 30-0, 31-0 & 32-0

1. No special requirements.

Units # 20-0 (19.5 MMBtu/hr, 27.6 MMBtu/hr, 41.5 MMBtu/hr heaters), 21-0, 22-0, 23-0 and 24-0

1. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction.

Unit # 26-0

1. Operation of the flare shall not exceed 93 hours per calendar year.[8]

Unit # 27-0

1. The PM_{10} emissions rate shall not exceed 0.087 g/bhp-hr based on US EPA certification using ISO 8178 test procedure.
2. 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.
3. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year.

Unit # 28-0

1. The PM_{10} emissions rate shall not exceed 0.022 g/bhp-hr based on US EPA certification using ISO 8178 test procedure.
2. 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.
3. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year.

Rule 4201 Particulate Matter Concentration

State the purpose of the Rule and include the calculation.

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

N-9742-20-0: HydroFlex Fuel Production Unit

The particulate matter concentration is calculated as follows:

[8]The suggested 93-hour limit for the flare was based upon an annual heat input limit of 7,400 MMBtu/rolling 12-months that was used to process the risk management review. Since the flare is not equipped with an hour meter, the rolling 12-month heat input has been limited on the permit and will enforce the assumptions used in determining the health risk from the flare.

$$PM\ Concentration = \frac{EF\,\frac{lb-PM}{MMBtu}\,x\,7000\,\frac{grains}{lb}}{8578\,\frac{dscf}{MMBtu}\,x\,(\frac{20.95}{17.59})}$$

Each of the three process heaters in this permit has the same limit of 0.003 lb-PM10/MMBtu and all PM is assumed to be PM10. Thus,

$$PM\ Concentration = \frac{0.003\,\frac{lb-PM}{MMBtu}\,x\,7000\,\frac{grains}{lb}}{8578\,\frac{dscf}{MMBtu}\,x\,(\frac{20.95}{17.59})} = 0.002\,\frac{grains}{dscf}$$

Thus, each of the process heaters is expected to comply with the Rule 4201 concentration requirement.

N-9742-21-0: Hydrogen Production Unit

For the process heater, the particulate matter concentration is calculated as follows:

$$PM\ Concentration = \frac{EF\,\frac{lb-PM}{MMBtu}\,x\,7000\,\frac{grains}{lb}}{8578\,\frac{dscf}{MMBtu}\,x\,(\frac{20.95}{17.59})}$$

The process heater in this permit has a limit of 0.0038 lb-PM10/MMBtu and all PM is assumed to be PM10. Thus,

$$PM\ Concentration = \frac{0.0038\ \frac{lb-PM}{MMBtu}\,x\,7000\,\frac{grains}{lb}}{8578\,\frac{dscf}{mmbtu}\,x\,(\frac{20.95}{17.59})} = 0.003\,\frac{grains}{dscf}$$

Thus, the process heater is expected to comply with the Rule 4201 concentration requirement.

The particulate matter concentration for RTO #1 will be calculated as follows:

$$PM\ Concentration = \frac{PE\ PM\ \frac{lb}{hr}\ x\,7000\,\frac{grains}{lb}}{Exhaust\ Rate\ \frac{dscf}{min}\,x60\,\frac{min}{hr}}$$

The total daily emission rate for the thermal oxidizer is 3.4 lb-PM10/day (0.14 lb-PM10/hr) and all PM is expected to be PM10. The exhaust rate for the thermal oxidizer is 20,000 dscfm. Thus,

$$PM\ Concentration = \frac{0.14\ \frac{lb}{hr}\ x\ 7000\frac{grains}{lb}}{20{,}000\ \frac{dscf}{min} x60 \frac{min}{hr}} = 0.0008 \frac{grains}{dscf}$$

Therefore, the thermal oxidizer is expected to comply with the particulate matter concentration requirement.

<u>N-9742-22-0: Boiler</u>

For the boiler, the particulate matter concentration is calculated as follows:

$$PM\ Concentration = \frac{EF\frac{lb-PM}{MMBtu} x\ 7000\frac{grains}{lb}}{8578\frac{dscf}{MMBtu} x\ (\frac{20.95}{17.59})}$$

The boiler in this permit has a limit of 0.003 lb-PM10/MMBtu and all PM is assumed to be PM10. Thus,

$$PM\ Concentration = \frac{0.003\ \frac{lb-PM}{MMBtu} x\ 7000\frac{grains}{lb}}{8578\frac{dscf}{mmbtu} x\ (\frac{20.95}{17.59})} = 0.002 \frac{grains}{dscf}$$

Thus, the boiler is expected to comply with the Rule 4201 concentration requirement.

<u>N-9742-23-0: Material Transfer Operation</u>

The particulate matter concentration for RTO #2 will be calculated as follows:

$$PM\ Concentration = \frac{PE\ PM\ \frac{lb}{hr}\ x\ 7000\frac{grains}{lb}}{Exhaust\ Rate\ \frac{dscf}{min} x60 \frac{min}{hr}}$$

The total daily emission rate for the thermal oxidizer is 3.4 lb-PM10/day (0.14 lb-PM10/hr) and all PM is expected to be PM10. The exhaust rate for the thermal oxidizer is 20,000 dscfm. Thus,

$$PM\ Concentration = \frac{0.14\ \frac{lb}{hr}\ x\ 7000\frac{grains}{lb}}{20{,}000\ \frac{dscf}{min} x60 \frac{min}{hr}} = 0.0008 \frac{grains}{dscf}$$

Therefore, the thermal oxidizer is expected to comply with the particulate matter concentration requirement.

N-9742-24-0: Wastewater Treatment Unit

This unit shares RTO #1 with N-9742-21-0. As calculated earlier, RTO #1 is expected to comply with the particulate matter concentration requirements.

N-9742-25-0: Cooling Tower

District Rule 4201 requirements are intended for point sources of emissions. The cooling tower is not a point source of emissions; therefore, District Rule 4201 requirements are not applicable.

N-9742-26-0: Emergency Flare

The particulate matter concentration for the flare will be calculated as follows:

$$PM\ Concentration = \frac{PE\ PM\ \frac{lb}{hr}\ x\ 7000\,\frac{grains}{lb}}{Exhaust\ Rate\ \frac{dscf}{min}\,x60\,\frac{min}{hr}}$$

The total daily emission rate for the flare is 95 lb-PM10/day (4.0 lb-PM10/hr) and all PM is expected to be PM10. The exhaust rate for the flare is 12,322 dscfm. Thus,

$$PM\ Concentration = \frac{4.0\ \frac{lb}{hr}\ x\ 7000\,\frac{grains}{lb}}{12{,}322\ \frac{dscf}{min}\,x60\,\frac{min}{hr}} = 0.04\,\frac{grains}{dscf}$$

,

Therefore, the flare is expected to comply with the particulate matter concentration requirement.

N-9742-27-0: Emergency Firewater Pump

Rule 4201 limits particulate matter emissions from any single source operation to 0.1 g/dscf, which, as calculated below, is equivalent to a PM_{10} emission factor of 0.4 g-PM_{10}/bhp-hr.

$$0.1\ \frac{grain - PM}{dscf} \times \frac{g}{15.43\,grain} \times \frac{1\,Btu_{in}}{0.35\,Btu_{out}} \times \frac{9{,}051\,dscf}{10^6\,Btu} \times \frac{2{,}542.5\,Btu}{1\,bhp - hr} \times \frac{0.96\,g - PM_{10}}{1\,g - PM} = 0.4\,\frac{g - PM_{10}}{bhp - hr}$$

The new engine has a PM_{10} emission factor less than 0.4 g/bhp-hr. Therefore, compliance is expected.

N-9742-28-0: Emergency Electrical Generator

Rule 4201 limits particulate matter emissions from any single source operation to 0.1 g/dscf, which, as calculated below, is equivalent to a PM_{10} emission factor of 0.4 g-PM_{10}/bhp-hr.

$$0.1\ \frac{grain-PM}{dscf} \times \frac{g}{15.43grain} \times \frac{1\ Btu_{in}}{0.35\ Btu_{out}} \times \frac{9{,}051dscf}{10^6\ Btu} \times \frac{2{,}542.5\ Btu}{1bhp-hr} \times \frac{0.96g-PM_{10}}{1g-PM} = 0.4\ \frac{g-PM_{10}}{bhp-hr}$$

The new engine has a PM_{10} emission factor less than 0.4 g/bhp-hr. Therefore, compliance is expected.

Rule 4301 Fuel Burning Equipment

This rule is applicable to any furnace, boiler apparatus, stack used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer. This rule specifies maximum emission rates in lb/hr for SO_2, NO_2, and combustion contaminants (defined as total PM in Rule 1020). This rule also limits combustion contaminants to ≤ 0.1 gr/scf. The emissions rates from the proposed modified boiler are shown in the table below.

District Rule 4301 Limits			
Pollutant	NO_2 (lb/hr)	Total PM (lb/hr)	SO_2 (lb/hr)
N-9742-20-0 Process Heater #1	1.2 (startup/shutdown)	0.06	0.05
N-9742-20-0 Process Heater #2	1.7 (startup/shutdown)	0.08	0.08
N-9742-20-0 Process Heater #3	2.6 (startup/shutdown)	0.13	0.12
N-9742-21-0 Process Heater	25.8 (startup/shutdown)	0.70	2.34
N-9742-22-0 Auxiliary Boiler	3.7 (startup/shutdown)	0.18	0.17
Rule Limit	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule. Furthermore, units fired on gaseous fuels are expected to comply with the grains/dscf limit. Therefore, compliance is expected.

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

This rule provides equipment tuning procedures for boilers, steam generators, and process heaters, if the units are required to be tuned periodically. Each of the units in this project will be monitored monthly with a portable analyzer; therefore, tuning of the units is not required by any of the regulations that the units are subject to. Therefore, the tuning requirements of District Rule 4304 are not applicable to the units in this project.

District Rule 4305 Boilers, Steam Generators, and Process Heaters – Phase 2

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

District Rule 4306 Boilers, Steam Generators, and Process Heaters – Phase 3

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

District Rule 4311 Flares

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

Flares are defined as a combustion device that oxidizes combustible gases or vapors, where the combustible gases and vapors being destroyed are routed into the burner without heat recovery. The proposed regenerative thermal oxidizers in this project have heat recover; therefore, they are not subject to the requirements of District Rule 4311. The proposed flare (N-9742-26-0) is subject to the requirements of Rule 4311.

Section 5.1 states that 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 of this Rule. The proposed flare will be limited to only operate during emergencies. The following condition will be included on the flare permit:

- *This flare shall only be operated during an emergency. An emergency is any situation or condition arising from a sudden or reasonably unforeseeable and unpreventable event beyond the control of the operator. Examples include, but are not limited 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 quality as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered an emergency. [District Rule 4311]*

Section 5.2 is applicable to flares limited to 200 hours per calendar year. The proposed flare does not fall under this category.

Section 5.3 states that the flame shall be present at all times when combustible gases are vented through the flare. The following condition will be included on the flare permit:

- *The flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311]*

Section 5.4 states that 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 ae vented through the flare, except during purge periods for automatic-ignition equipped flares. The following condition will be included on the flare permit:

- *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 states that 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. The following condition will be included on the flare permit:

- *Except for flares equipped with a flow-sensing ignition, 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]*

Section 5.6 states that flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging. The following condition will be included on the flare 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 stated earlier, sections 5.7 through 5.10 are not applicable to emergency flares.

Section 5.11 requires flaring to be consistent with an approved flare minimization plan pursuant to Section 6.5 of the Rule. This requirement is only applicable to petroleum refineries and flaring at major sources (except landfills). This facility is not a petroleum refinery and is not a major source; therefore, this requirement is not applicable.

Section 5.12 list SO_2 performance targets for flares at petroleum refineries. Since the proposed facility is not a petroleum refinery, the requirements of this section are not applicable.

Section 5.13 is only applicable to petroleum refineries and flaring at major sources (except landfills). Since the proposed facility is not a petroleum refinery and is not a major source, the requirements of this section are not applicable.

Section 5.14 is applicable to operators of a flare subject to an annual throughput threshold listed in Table 2 of the Rule. This unit is not subject to an annual throughput threshold listed in Table 2; therefore, the requirements of this section are not applicable.

Section 5.15 is only applicable to petroleum refineries and flaring at major sources (except landfills). Since the proposed facility is not a petroleum refinery and is not a major source, the requirements of this section are not applicable.

Section 6.1 requires the following records to be kept for the proposed flare:

1. A record of the duration of flare operation, amount of gas burned, and the nature of the emergency situation.
2. All flare monitoring data.

The records must be kept for a minimum of five years and be made available upon request. The following conditions will be included on the flare permit:

- *The owner or operator shall keep a record of the duration of flare operation, the amount of gas burned, and the nature of the emergency situation that required flaring to occur. [District Rule 4311]*

- *The owner or operator shall keep a record of all flare monitoring data required by this permit. [District Rule 4311]*

- *All records shall be kept for a minimum of five years and shall be made available to the APCO, ARB, and EPA upon request. [District Rule 4311]*

Section 6.2, flare reporting, includes requirements that only apply to sources that are subject to a flare minimization plan or are located at a petroleum refinery or major source. The proposed flare is not subject to a flare minimization plan; therefore, the requirements of this section are not applicable.

Section 6.3 lists test methods for source testing and flare monitoring. The following conditions will be included on the permit:

- *Total hydrocarbon content and methane content of vent gas shall be determined using ASTM Method D 1945-96, ASTM Method UOP 539-97, EPA Method 18, or EPA Method 25A or 25B. [District Rule 4311]*

- *Hydrogen sulfide content of vent gas shall be determined using ASTM Method D1945-96, ASTM Method UOP 539-97, ATM Method D 4084-94, or ASTM Method D4810-88. [District Rule 4311]*

- *If vent gas composition is monitored with a continuous analyzer employing gas chromatography, the minimum sampling frequency shall be one sample every 30 minutes. [District Rule 4311]*

- *If vent gas composition is monitoring using continuous analyzers not employing gas chromatography, the total reduced sulfur content of vent gas shall be determined using EPA Method D4468-85. [District Rule 4311]*

Section 6.4 lists compliance determination requirements. The proposed flare is not subject to any of the requirements that would require testing; therefore, this section is not applicable.

Section 6.5 lists flare minimization plan requirements. Since this flare is not located at a petroleum refinery or at a major source, the requirements of this section are not applicable.

Section 6.6 states that effective January 1, 2024, the operator of any flare with a flaring capacity equal to or greater than 50 MMBtu/hr shall monitor vent gas composition using one of the five methods below:

1. Sampling
2. Integrated sampling
3. Continuous analyzer
4. Continuous analyzer employing gas chromatography
5. Monitor sulfur content using a colorimetric tube system, and monitor vent gas hydrocarbon by collecting samples.

The following conditions will be included on the permit:

- *The owner or operator shall monitor the vent gas composition using one of the five following methods: 1) sampling; or 2) integrated sampling; or 3) use of a continuous analyzer not employing gas chromatography; or 4) use of a continuous analyzer employing gas chromatography; or 5) monitoring of sulfur content using a colorimetric tube system and monitoring of vent gas hydrocarbon by collecting samples. [District Rule 4311]*

- *If the owner or operator chooses to monitor the vent gas composition using sampling, the following requirements are applicable: If the flow rate of vent gas in any consecutive 15-minute period continuously exceeds 330 standard cubic feet per minute (SCFM), a sample shall be taken within 15 minutes. The sampling frequency thereafter shall be one sample every three hours and shall continue until the flow rate of vent gas flared in any consecutive 15-minute period is continuously 330 SCFM or less. In no case shall a sample be required more frequently than once every 3 hours. Samples shall be analyzed for total hydrocarbons, methane, and hydrogen sulfide pursuant to the test methods listed in this permit. [District Rule 4311]*

- *If the owner or operator chooses to monitor the vent gas composition using integrated sampling, then the following requirements are applicable: If the flow rate of vent gas flared in any consecutive 15 minute period continuously exceeds 330 SCFM, integrated sampling shall begin within 15 minutes and shall continue until the flow rate of the vent gas flared in any consecutive 15 minutes is continuously 330 SCFM or less. Integrated sampling shall consist of a minimum of one aliquot for each 15-minute period until the sample container is full. If sampling is still required, a new sample container shall be placed in service within one hour after the previous sample container was filled. A sample container shall not be used for a sampling period that exceed 24 hours. Samples shall be analyzed for total hydrocarbons, methane, and hydrogen sulfide pursuant to the test methods listed in this permit. [District Rule 4311]*

- *If the owner or operator chooses to monitor the vent gas composition using continuous analyzers not equipped with gas chromatography, then the following requirements are applicable: The analyzers shall continuously monitor for total hydrocarbon and methane, and depending upon the analytical method used, hydrogen sulfide or total reduced sulfur. The hydrocarbon analyzer shall have a full-scale range of 100% of the total hydrocarbon. Each analyzer shall be maintained to be accurate to within 20% when compared to field accuracy tests, or to within 5% of full scale. [District Rule 4311]*

- *If the owner or operator chooses to monitor the vent gas composition using continuous analyzers employing gas chromatography, then the following requirements are applicable: The gas chromatography system shall monitor for total hydrocarbon, methane, and hydrogen sulfide. The gas chromatography system shall be maintained to be accurate within 5% of full scale. [District Rule 4311]*

- *If the owner or operator chooses to monitor the vent gas composition using a colorimetric tube system for sulfur content, and monitor vent gas hydrocarbon by collecting samples, then the following requirements are applicable: Owner or operator shall monitor sulfur content using a colorimetric tube system on a daily basis, and monitor vent gas hydrocarbon on a weekly basis using collected samples. Collected samples shall be analyzed for total hydrocarbon and methane content using the test methods listed in this permit. [District Rule 4311]*

Section 6.7 lists pilot and purge gas monitoring requirements for flares. Effective January 1, 2024, flares greater than 50 MMBtu/hr must 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 gas may be calculated based on pilot design and the parameters monitored. The following condition will be included on the flare permit:

- *The owner or operator shall monitor the volumetric flows of purge and pilot gases with flow measuring devices, or using a District approved calculation method based on pilot system design and parameters monitored. [District Rule 4311]*

Section 6.8 states that the owner or operator of any flare with a rated capacity of greater than 50 MMBtu/hr must monitor and record the water level and pressure of the water seal that services each flare daily. The following condition will be included on the flare permit:

- *If the flare is equipped with a water seal, the owner or operator shall monitor the water level and pressure of the water seal daily. [District Rule 4311]*

Section 6.9.1 states that periods of flare monitoring system inoperation greater than 24 continuous hours shall be reported by the following working day, followed by notification of the resumption of monitoring. Periods of inoperation of monitoring equipment must not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include periods when the system feeding the flare is not operation. The following condition will be included on the flare permit:

- *Periods of flare monitoring system inoperation greater than 24 continuous hours shall be reported by the following working day, followed by notification of the resumption of monitoring. Periods of inoperation of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include periods where the system feeding the flare is not in operation [District Rule 4311]*

Section 6.9.2 states that during periods of inoperation of continuous analyzers or auto-samplers (if utilized), operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas compositions and the samples shall be analyzed pursuant to Section 6.3.4. The following condition will be included on the flare permit:

- *During periods of inoperation of continuous analyzers or auto-samplers (if utilized), operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas compositions and the samples shall be analyzed for total hydrocarbons, methane, and hydrogen sulfide using the test methods listed on this permit. [District Rule 4311]*

Section 6.9.3 states that operators and owners must maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. The following condition will be included on the flare permit:

- *Operators and owners shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions shall have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. [District Rule 4311]*

Section 6.9.4 states that all in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. The following condition will be included on the flare permit:

- *If equipped, all in-line continuous analyzers and flow monitoring data shall be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. [District Rule 4311]*

Section 6.10 lists video monitoring requirements for flares at petroleum refineries. Since the proposed flare is not operating at a petroleum refinery, the requirements of this section are not applicable.

Compliance with the requirements of District Rule 4311 is expected.

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

This rule limits emissions of NOx, CO, SO2, and PM_{10} from boilers, steam generators, and process heaters with a total rated heat input greater than 5 MMBtu/hr. The three process heaters under permit N-9742-20-0, the process heater under permit N-9742-21-0, and the boiler under N-9742-22-0 are subject to the requirements of this Rule.

Section 5.1 requires each of the units to either comply with one of the following:

1. Comply with the emission limits specified in Sections 5.2 and 5.4; or
2. Pay an annual emissions fee to the District as specified in Section 5.3 and comply with the control requirements specified in Section 5.4; or
3. Comply with the applicable Low-use Unit requirements of Section 5.5

The applicant has opted to comply with the emission limits specified in Sections 5.2 and 5.4. The applicant is proposing to comply with the applicable Tier 2 NOx emission limits for each unit. The following table shows the applicable NOx limit for each unit in this project.

Unit	Category	NOx Limit (ppmv @ 3% O_2)
N-9742-20-0 Process Heater #1 (19.5 MMBtu/hr)	Table 2 A.5	5
N-9742-20-0 Process Heater #2 (27.6 MMBtu/hr)	Table 2 B.2	2.5
N-9742-20-0 Process Heater #3 (41.5 MMBtu/hr)	Table 2 B.2	2.5
N-9742-21-0 Process Heater (184 MMBtu/hr)	Table 2 B.3	2.5
N-9742-22-0 Auxiliary Boiler (59 MMBtu/hr)	Table 2 B.2	2.5

Section 5.2.1 states that the CO emissions must not exceed 400 ppmv @ 3% O_2.

The applicant is proposing to meet the above limits for each permit. The conditions shown earlier in the Rule 2201 Daily Emission Limits (DEL) section of this document enforce the above emission limits.

Section 5.4 states that to limit particulate matter emissions, an operator must comply with one of the following requirements:

1. Fire units exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases.
2. Limit fuel sulfur content to no more than five grains of total sulfur per one hundred standard cubic feet; or
3. Properly install an emission control system that reduces SO_2 by at least 95% by weight, or limit exhaust SO_2 to less than or equal to 9 ppmv corrected to 3.0% O_2.

The three process heaters under Permit N-9742-20-0 and the auxiliary boiler under permit N-9742-22-0 will be fired exclusively on PUC-quality natural gas. A permit condition requiring the units to be fired on PUC-quality natural gas was presented earlier in the District Rule 2201 DEL section of this document.

The 184 MMBtu/hr process heater under N-9742-21-0 will be fired on a combination of process gas and natural gas. The process gas will have a maximum sulfur content of 1.75 grains/dscf; therefore, compliance with a limit of five grains of total sulfur per 100 standard cubic feet is expected. The following condition will be included on permit N-9742-21-0:

- *The sulfur content of the process gas combusted in the process heater shall not exceed 1.75 grains/100 dscf. [District Rules 2201, 4305, 4306, and 4320]*

Section 5.5 is only applicable to low-use units. The applicant is not proposing any low-use units; therefore, this section is not applicable.

Section 5.6 lists start-up and shutdown provisions. Section 5.6.1 states that the duration of each start-up and each shutdown may not exceed two hours, except as provided in Section 5.6.3. For the three process heaters associated with the HydroFlex unit and the process heater associated with the hydrogen production unit, the applicant has requested a longer startup time. For the auxiliary boiler, the applicant has only requested a 2-hour startup/shutdown per event.

Section 5.6.2 states that the emission control system must be in operation and emissions minimized insofar as technologically feasible during start-up and shutdown.

Pursuant to Section 5.6.3, the applicant has requested an 8-hour start-up time for the process heaters associated with the HydroFlex production unit and a 12-hour start-up time for the hydrogen production unit. The applicant is not requesting shutdown periods longer than 2 hours. To be allowed longer startup times, the applicant's proposal must meet the requirements of Section 5.6.3.1 through 5.6.3.3, which are:

- 5.6.3.1: The maximum allowable duration of start-up or shutdown will be determined by the APCO. The allowable duration of start-up shall not exceed twelve hours and the allowable duration of shutdown shall not exceed nine hours.

Section 5.6.3.2 states that the APCO will only approve start-up or shutdown duration longer than two hours when the application meets the following conditions:

- 5.6.3.2.1 Clearly identifies the control technologies or strategies to be utilized; and
- 5.6.3.2.2 Describes what physical conditions prevail during start-up or shutdown periods that prevent the controls from being effective; and
- 5.6.3.2.3 Provides a reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions.

Section 5.6.3 states that the operator shall submit to the APCO any information deemed necessary to determine the appropriate length of start-up or shutdown. The information should include, but is not limited to the following:

- 5.6.3.3.1 A detailed list of activities to be performed during start-up or shutdown and a reasonable explanation for the length of time needed to complete each activity
- A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of the activities and process flow affect operation of the emissions control equipment; and
- The basis for the requested additional duration of start-up and shutdown.

The applicant is proposing an 8-hour start-up period for the three process heaters associated with the HydroFlex production unit and the auxiliary boiler, and is proposing a 12-hour start-up period for the process heater associated with the hydrogen production unit. These periods are not greater than the maximum allowable periods allowed in Section 5.6.3.1. The applicant's proposal clearly identifies selective catalytic reduction as the control to be utilized by each of the four process heaters and the auxiliary boiler. While the selective catalytic reduction system begins operating at approximately 450 degrees Fahrenheit, the selective catalytic reduction system does not meet optimal control until 700 to 800 degrees Fahrenheit. The maximum per hour warm-up rate for the process heaters and the auxiliary boiler is 100 degrees Fahrenheit. Warm-up rates beyond this value may damage processing equipment in the plant. Therefore, it is estimated that up to 8-hours of warm-up is required to meet the optimal temperature of the SCR system, and an 8-hour start-up time is required for the HydroFlex process heaters. For the process heater associated with the hydrogen production unit, the maximum warm-up rate is 50 degrees Fahrenheit per hour. This rate prevents fracture of the fire brick in the hydrogen production unit. Therefore, the applicant has requested the maximum start-up period of 12 hours for that process heater.

Finally, Section 5.6.3.3 states that the operator must submit to the APCO any information deemed necessary by the APCO to determine the appropriate length of start-up or shutdown. The information shall include, but is not limited to:

- A detailed list of activities to be performed during start-up or shutdown and a reasonable explanation for the length of time needed to complete each activity
- A description of the material process flow rates and system operating parameters, etc, the operator plans to evaluate during the process optimization and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and

- The basis for the requested additional duration of start-up or shutdown.

As stated above, the operator has requested additional start-up time based on the manufacturer’s recommended warm-up rates for the HydroFlex and hydrogen production units and has described why their proposed start-up durations are reasonable.

Conditions enforcing the startup and shutdown requirements of this section were included in the Rule 2201 DEL section of this document.

Section 5.7 lists monitoring provisions for units subject to District Rule 4320. Section 5.7.1 states that either a CEMS or alternate monitoring is required. The applicant has proposed to comply with a pre-approved alternate monitoring plan that requires monthly measurements with a portable analyzer. The following conditions will be included on each permit that includes a unit subject to this Rule:

- *The permittee shall monitor and record the stack concentration of NOx, CO, NH3 and O2 at least once during each month in which source testing is not performed. NOx, CO and O2 monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH3 monitoring shall be conducted utilizing gas detection tubes (Draeger brand or District approved equivalent). Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless it has been performed within the last month. [District Rules 4305, 4306 and 4320]*

- *If either the NOx, CO or NH3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4320]*

- *All NOx, CO, O2 and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NOx, CO and O2 analyzer as well as the NH3 emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]*

- *Ammonia emissions readings shall be conducted at the time the NOx, CO and O2 readings are taken. The readings shall be converted to ppmvd @ 3% O2. [District Rules 4305, 4306, and 4320]*

- *The permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx, CO and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 4305, 4306 and 4320]*

Section 5.7.6 states that operators complying with Section 5.4.1.1 or 5.4.1.2 must provide an annual fuel analysis to the District. An annual fuel analysis is not required for units that the facility can demonstrate are only fired on PUC quality natural gas. The following conditions will be included on each permit containing a unit subject to District Rule 4320 requirements:

- *The permittee shall determine the sulfur content of combusted gas annually and shall maintain records of the fuel sulfur content or shall maintain records of fuel purchase contracts, supplier certifications, tariff sheets, or transportation contracts demonstrating that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320]*

- *The fuel sulfur content shall be determined using EPA Method 11 or EPA Method 15 or District, CARB and EPA approved alternative methods. [District Rule 4320]*

Section 5.8.1 states that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the each permit that includes a unit subject to District Rule 4320 requirements to ensure compliance:

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

Section 5.8.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0.

Therefore, the following condition will be listed on each permit that includes a unit subject to the requirements of Rule 4320 to ensure compliance:

- *All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period* *in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 4305, 4306 and 4320]*

Section 5.8.3 requires that all CEMS data shall be averaged over a period of 15-consecutive minutes to demonstrate compliance with the applicable emission limits in this rule. The applicant is not proposing to install a CEMs on any of the proposed boilers and process heaters. Therefore, this requirement is not applicable.

Section 5.8.4 requires that for emissions monitoring using a portable NOx analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period. Therefore, the following condition will be included on the permits that contain units subject to the requirements of District Rule 4320:

- *All NOx, CO, O2 and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NOx, CO and O2 analyzer as well as the NH3 emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]*

Section 5.8.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following condition will be listed on each permit that contains a unit subject to District Rule 4320 requirements:

- *For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306 and 4320]*

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.5 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule. The following condition will be included on each permit that contains a unit subject to District Rule 4320 requirements.

- *All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320]*

Section 6.2, Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NOx	ppmv	EPA Method 7E or ARB Method 100
NOx	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O_2	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2 or 19
Stack Gas Moisture Content	%	EPA Method 4

Conditions enforcing the above testing requirements were included in the District Rule 2201 section of this document.

Section 6.3 Compliance Testing

Section 6.3.1 requires that the boiler be tested to determine compliance with the applicable requirements of section 5.2 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the source test may be deferred for up to thirty-six months.

Conditions enforcing the above requirements were included in the District Rule 2201 section of this document.

In conclusion, compliance with the requirements of District Rule 4320 is expected.

District Rule 4455 Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants

This rule limits VOC emissions from leaking components at petroleum refineries, gas liquids processing facilities, and chemical plants. The proposed facility meets the definition of a chemical plant, which is an establishment that produces organic chemicals and/or manufactures products by organic chemical processes; therefore, the requirements of this Rule are applicable. The HydroFlex unit (N-9742-20-0), the hydrogen production unit (N-9742-21-0), and the wastewater treatment plant (N-9742-24-0) are subject to the requirements of this Rule.

Section 5.1.1 states that the operator shall not use any component that leaks in excess of the applicable standards of this rule, or that is found to be in violation of the provisions specified in Section 5.1.3. Components found leaking in excess of the applicable leak standards of this rule may be used provided such leaking components have been identified with a tag for repair, are repaired, or are awaiting re-inspection after being repaired, within the applicable time period specified in this rule. The facility has proposed to limit gas leaks concentrations to levels much lower than Rule 4455 for compliance with BACT requirements; therefore, the condition will reference the proposed leak limits rather than the definition of gas leaks in District Rule 4455.

The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall not use any component that leaks in excess of the leak limits of this permit, except as follows. A component identified as leaking in excess of the leak limits of this permit may be used provided it has been identified with a tag for repair, has been repaired, or is awaiting re-inspection after repair, within the applicable time period specified within Rule 4455. [District Rules 2201 and 4455]*

Section 5.1.2 states that each hatch must be closed at all times except during sampling or adding process material through the hatch, or during attended repair, replacement or maintenance operations, provided such activities are done as expeditiously as possible with minimal spillage of material and VOC emissions to the atmosphere.

The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere. [District Rule 4455]*

Section 5.1.4.1 through 5.1.4.4 describe what constitutes a minor and major leak, and describes what percentage of components can have minor/major leaks before a violation occurs. The proposed chemical plant operations are subject to BACT requirements, which have more stringent leak limits than District Rule 4455. Furthermore, any leak results in emissions above those allowed by the proposed permit. Since the proposed conditions for complying with Rule 2201 for leaks is more stringent, additional conditions are not required for Sections 5.1.4.1 through 5.1.4.4 of this Rule.

Section 5.2.1 states that the operator must audio-visually (by hearing and sight) inspect for leaks from all accessible operating pumps, compressors, and pressure relief devices (PRDs) in service at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The owner or operator shall audio-visually inspect (by hearing and sight) all accessible operating pumps, compressors and pressure relief devices for leaks at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. [District Rule 4455]*

Section 5.2.2 states that the audio inspection of all accessible operating pumps, compressors, and PRDs in service performed by an operator that indicates a leak that cannot be immediately repaired to meet the leak requirements must be inspected using the test method specified in Section 6.4.1 not later than 24 hours after conducting the audio-visual inspection. If a leak is found, it must be repaired as soon as practicable but no later than the time frame specified in Table 3 of this rule. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *Any audio-visual inspection of all accessible operating pumps, compressors, and pressure relief devices in service that indicates a leak that cannot be immediately repaired to meet the leak requirements of this permit shall be inspected to determine the gaseous leak concentration using an instrument in accordance with EPA Method 21 not later than 24 hours after conducting the audio-visual inspection. If the gas leak concentration is greater than 50,000 ppmv (as methane), the leak must be repaired within 2 calendar days. If the gas leak concentration is greater than the gas leak concentration is greater than 10,000 ppmv but equal to or less than 50,000 ppmv (as methane), the leak must be repaired 3 calendar days. If the leak is greater than the leak concentrations allowed in this permit but less than or equal to 10,000 ppmv (as methane), then the leak must be repaired within 7 calendar days. [District Rules 2201 and 4455]*

Section 5.2.3 states that notwithstanding the requirements of Section 5.2.1 and 5.2.2, the operator must inspect all components at least once every calendar quarter using the test method specified in Section 6.4.1, except for inaccessible components, unsafe-to-monitor components, or pipes. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall inspect all components at least once every calendar quarter using an instrument in accordance with EPA Method 21, except for inaccessible components and unsafe-to-monitor components, or pipes. [District Rule 4455]*

Section 5.2.4 states that the operator shall inspect, immediately after placing into service, all new, replaced, or repaired fittings, flanges, and threaded connections using the test method specified in Section 6.4.1. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall inspect, immediately after placing into service, all new, replaced, or repaired fittings, flanges, and threaded connections using an instrument in accordance with EPA Method 21. [District Rule 4455]*

Section 5.2.5 states that the operator must inspect all inaccessible components at least once every 12 months using the test method specified in Section 6.4.1. The following condition will be included on permits N-9742-20-0, '-21-0 and '-24-0:

- *The operator shall inspect all inaccessible components at least once every 12 months using an instrument in accordance with EPA Method 21. [District Rule 4455]*

Section 5.2.6 states that the operator shall inspect all unsafe-to-monitor components during each turnaround using the test method specified in Section 6.4.1. The following condition will be included on permits N-9742-20, '-21, and '-24:

- *The operator shall inspect all unsafe-to-monitor components during each turnaround using an instrument in accordance with EPA Method 21.[District Rule 4455]*

Section 5.2.7 states that the operator must inspect all pipes for leaks at least every 12 months. Section 5.2.7.1 states that any visual inspection that indicates a leak that cannot be repaired to meet the leak standards of this rule must be inspected using the test method specified in Section 6.4.1 within 24 hours after conducting the audio-visual inspection. If a leak is found, it must be repaired as soon as practicable but no later than the timeframe specified in Table 3 of this Rule. Section 5.2.7.2 states that this inspection may be conducted in conjunction with the annual pipe inspection required by Title 40 CFR 112. This facility is not subject to Title 4 Part 112. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall perform an audio-visual inspection on all pipes for leaks at least every 12 months. Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this permit shall be inspected using an instrument in accordance with EPA Method 21 within 24 hours after conducting the audio-visual inspection. If there is a visible mist or continuous flow of liquid that is not seal lubricant from the pipe, the leak must be fixed within 2 calendar days of detection. If there is a liquid leak, except seal lubricant, that is not a visible mist or continuous flow and drips liquid at a rate of more than three drops per minute, the leak shall be fixed within 3 calendar days of detection. [District Rule 4455]*

Section 5.2.8 states that until June 30, 2024, the operator may apply for written approval from the APCO to change the inspection frequency from quarterly to annual for a component type provided the operator meets all of the following. This approval applies to accessible component types specifically designated by the APCO, except pumps, compressors and pressure relief devices that must continue to be conducted on a quarterly basis.

1. The operator was not in violation of any provisions in Section 5.1 during five consecutive quarterly inspections for that component type.
2. The operator did not receive a Notice of Violation from the APCO during the previous 12 months for violating any provisions of Rule 4455 for that component type.
3. The written request shall include pertinent documentation to demonstrate that the operator has successfully met 5.2.8.1 and 5.2.8.2.

Section 5.2.9 states that until June 30, 2024, the annual inspection shall revert back to quarterly for a component type if:

1. Operator or District inspection demonstrates that a violation of the leak provisions of this permit has occurred for that component type; or
2. The APCO issues a Notice of Violation for violating any of the provisions of Rule 4455 during the annual inspection period for that component type.

Section 5.2.10 states that until June 30 2024, when the inspection frequency changes from annual to quarterly inspections, the operator shall notify the APCO in writing within five calendar days after changing the inspection frequency. The written notification shall include the reason(s) and date of change to quarterly inspection frequency. Since this equipment has yet to be installed, it will not have operated for 12 months on June 30, 2024 and will not be able to take advantage of this provision. Therefore, no conditions will be included on the permits.

Section 5.2.11 states that the operator shall initially inspect a process PSD that releases to the atmosphere as soon as practicable but no later than 24 hours after the time of release. The operator shall re-inspect the process PRD using the test method in Section 6.4.1 not earlier than 24 hours after the initial inspection but not later than 15 calendar days after the date of the release to insure that the process PRD is operating properly, and is leak free. If the process PRD is found to be leaking at either inspection, the PRD leak shall be treated as if the leak was found during quarterly inspections. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall initially inspect a process pressure relief device that releases to the atmosphere as soon as practicable but no later than 24 hours after the time of release. The operator shall re-inspect the process pressure relief device using an instrument in accordance with EPA Method 21 no earlier than 24 hours after the initial inspection but no later than 15 calendar days after the date of the release to insure that the process pressure relief device is operating properly and is leak free. If the pressure relief device is found to be leaking at either inspection, the pressure relief device leak shall be treated as if the leak was found during quarterly inspections. [District Rule 4455]*

Section 5.2.12 states that except for process PSD subject to 5.2.11, a component shall be inspected within 15 calendar days after repairing the leak or replacing the component using the test method specified in Section 6.4.1. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *Except for process pressure relief devices, a component shall be inspected using an instrument in accordance with EPA Method 21 within 15 calendar days after repairing the leak or replacing the component. [District Rule 4455]*

Section 5.2.13 states that a District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required of an operator. Any attempt by an operator to count such District inspections as part of the mandatory operator's inspections is considered a willful circumvention of the rule and is a violation of this rule. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *A District inspection in no way fulfills any of the mandatory inspection requirements placed upon the operator and cannot be used or counted as an inspection required of an operator. Any attempt by an operator to count such District inspections as part of the mandatory operator's inspections is considered a willful circumvention of the Rule 4455 and is a violation of Rule 4455. [District Rule 4455]*

Section 5.3.1 states that upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag.

Section 5.3.2 states that the tag shall remain affixed to the component until all of the following conditions are met:

1. The leaking component has been repaired or replaced; and
2. The component has been re-inspected using an instrument in accordance with EPA Method 21; and
3. The component is found to be in compliance with the requirements of this Rule.

Section 5.3.3 states that the tag shall include the following information:

1. Date and time of leak detection.
2. Date and time of leak measurement.
3. For gas leaks, indicate the leak concentration in ppmv.
4. For liquid leaks, indicate whether the leak is a major liquid leak or minor liquid leak
5. For essential components, unsafe-to-monitor components, or critical components, so indicate on the tag.

The following condition will be included on Permits N-9742-20, '-21, and '-24:

- *Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag. The tag shall include the following information: 1) Date and time of leak detection; 2) Date and time of leak measurement; 3) for gas leaks, indicate the leak concentration in ppmv; 4) for liquid leaks, indicate whether the leak is a Major leak (a leak with visible mist or a continuous flow that is not seal lubricant) or a minor leak (a liquid leak that is not a Major leak, but is in excess of three drops per minute); and 5) For essential components, unsafe-to monitor components, and critical components, indicate so on the tag. The tag shall remain affixed to the component until all of the following conditions are met: 1) the leaking component has been repaired or replace; 2) The component has been re-inspected using an instrument in accordance with EPA Method 21; and 3) The component is found to be in compliance with the leak requirements of this permit. [District Rule 4455]*

Section 5.3.4 states that an operator shall minimize all component leaks immediately to the extent possible, but not later than one hour after detection of the leaks in order to stop or reduce leakage to the atmosphere.

Section 5.3.5 states that if the leak has been minimized but the leak still exceeds the applicable leak standards, an operator shall comply with at least one of options 3, 4, and 5 below as soon as possible, but not later than the time period specified in Table 4 or Table 5.

1. The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in Table 4 or Table 5.
2. The start of the repair period shall be the time of the initial leak detection.
3. Repair or replace the leaking component; or
4. Vent the leaking component to a closed vent system as defined in Section 3.0
5. Remove the leaking component from operation.

The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall minimize all component leaks immediately to the extent possible, but not later than one hour after detection of the leaks in order to stop or reduce leakage to the atmosphere. If the leak has been minimized but the leak still exceeds the applicable leak standards in this permit, the operator shall comply with at least one of the following as soon as possible: 1) Repair or replace the leaking component; or 2) Vent the leaking component to a closed vent system; or 3) Remove the leaking component from service. The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in Table 4 or Table 5 of Rule 4455. The start of the repair period shall be the time of the initial leak detection. [District Rule 4455]*

Section 5.3.6 states that if a leaking component is an essential component or a critical component and which cannot be immediately shut down for repairs, the operator shall:

1. Minimize the leak within one hour after detection; and
2. If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of this rule, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier.

The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *If a leaking component is an essential component or a critical component and which cannot be immediately shutdown for repairs, the operator shall: 1) Minimize the leak within one hour after detection; and 2) If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of this permit, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 4455]*

Section 5.3.7 states that for any component that has incurred five repair actions for major gas leaks or major liquid leaks, or any combination of major gas leaks and major liquid leaks within a continuous 12-month period, the operator shall comply with one of the following requirements:

1. Replace or retrofit the component with the control technology specified in Table 6 of District Rule 4455. Notify the APCO in writing prior to replacing or retrofitting the component; or
2. Replace the component with Achieved in Practice Best Available Control Technology (BACT) equipment, as determined in accordance with Rule 2201 and as approved by the APCO in writing; or
3. Vent the component to an APCO approved closed vent system; or
4. Remove the component from operation.

Pursuant to Section 5.3.7.5, for any component that is accessible, is not unsafe-to-monitor, is not an essential component, is not a critical component, the operator shall comply with these requirements as soon as practicable, but not later than 12 months after the date of detection of the fifth major leak within a continuous 12-month period.

Pursuant to Section 5.3.7.6, for any inaccessible component, unsafe-to-monitor component, essential component, and critical component, the operator shall comply with these requirements as soon as practicable but not later than the next turnaround or not later than two years after the date of detection of the fifth major leak within a continuous 12-month period, whichever comes earlier.

The following condition will be included on permits N-9742-20, '-21, and '-24:

- *For any component that has incurred five repair actions for major gas leaks (> 10,000 ppmv) or major liquid leaks (a visible mist or continuous flow of liquid that is not seal lubricant), or a combination of major gas leaks and major liquid leaks in a continuous 12 month period, the operator shall comply with at least one of the following: 1) Replace or retrofit the component with the control technology specified in Table 6 of Rule 4455 and notify the APCO in writing prior to replacing or retrofitting the component; or 2) Replace the component with Achieved-in-Practice Best Available Control Technology (BACT) equipment, as determined in accordance with District Rule 2201 and as approved by the APCO in writing; or 3) Vent the component to an APCO approved closed vent system or 4) Remove the component from operation. For any component that is accessible, is not unsafe-to-monitor, is not an essential component, and is not a critical component, the operator shall perform one of the above four actions as soon as practicable, but no later than 12 months after the date of detection of the fifth major leak in a continuous 12-month period. For any inaccessible component, unsafe-to-monitor component, essential component, or critical component, the operator shall perform one of the above four actions as soon as practicable but not later than the next turnaround or not later than 2 years after the date of detection of the fifth major component leak within a continuous 12-month period. An entire compressor or pump need not be replaced provided the compressor parts or pump parts that incurred five repair actions are brought into compliance. [District Rule 4455]*

Section 5.4.1 states that the operator shall monitor process PRD by using electronic process control instrumentation that allows for real time continuous parameter monitoring or by using telltale indicators for the process PRD where parameter monitoring is not feasible. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall monitor process pressure relief devices using electronic process control instrumentation that allows for real time continuous parameter monitoring or by using telltale indicators for the process pressure relief device where parameter monitoring is not feasible. [District Rule 4455]*

Section 5.4.2 states that the operator shall submit to the APCO a compliance plan as part of the Operator Management Plan required by Section 6.1 containing the inventory of process PRD by size, set pressure and location, and the type of monitoring system used. If applicable, the operator shall indicate the process parameter selected for continuous monitoring and justification for such selection. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall submit a compliance plan as part of the Operator Management Plan containing an inventory of process pressure relief devices by size, set pressure and location, and the type of monitoring system used. If applicable, the operator shall indicate the process parameter selected for continuous monitoring and justification for such selection. [District Rule 4455]*

Section 5.4.3 states that the operator shall comply with the Process PRD release notification and recordkeeping requirements of Section 6.3. The applicant is proposing to comply with these requirements.

Section 5.4.4 states that after the release from process PRD in excess of 500 pounds of VOC in a continuous 24-hour period, the operator shall immediately conduct a failure analysis and implement corrective actions as soon as practicable, but no later than 30 days to prevent the reoccurrence of such release. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *After the release from process pressure relief device in excess of 500 pounds of VOC in a continuous 24-hour period, the operator shall immediately conduct a failure analysis and implement corrective actions as soon as practicable, but no later than 30 days, to prevent the reoccurrence of such release. [District Rule 4455]*

Section 5.4.5 only applies to refinery processing. The proposed facility is not a crude oil refinery; therefore, Section 5.4.5 requirements are not applicable.

Section 5.5.1 states that all major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator or District personnel to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but no later than 24 hours after discovery. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *All major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator and District personnel to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but no later than 24 hours after discovery. [District Rule 4455]*

Section 5.5.2 states that the operator must comply with the requirement of Section 6.1.4 if there is any change in the description of major components or critical components. The applicant is proposing to comply with the requirements of Section 6.1.4.

Section 6.1.1 requires an operator to submit an Operator Management Plan for approval by the APCO.

Section 6.1.2 states that the operator shall keep a copy of the approved Operator Management Plan at the facility and make it available to the APCO, ARB, and US EPA upon request.

Section 6.1.3 states that the Operator Management Plan shall describe all components subject to Rule 4455 and all components except pursuant to Section 4.0 of this rule. The plan shall contain a description of the procedures that the operator will use to comply with the requirements of this rule. At a minimum, the plan shall include the following:

1. Identification and description of any known hazard that might affect the safety of an inspector.
2. Diagrams, charts, spreadsheets, or other methods approved by the APCO which describe the following information:
    a. Except for pipes, the number of components that are subject to Rule 4455 requirements b component type and type of service (liquid or gas).
    b. Except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components, and essential components, that are subject to Rule 4455 requirements, including the reason(s) for such designation.
    c. Except for pipes, the location of components that are subject to this rule.
    d. Except for pipes, components exempt pursuant to Section 4.2
3. Detailed schedule of inspection to be conducted as required by Rule 4455
4. Compliance plan for process PRD
5. Specify whether a qualified contractor or in-house team will perform the inspections.
6. Establish an employee training program for inspecting, repairing, and recordkeeping procedures as necessary.
    a. Specify the training standards for personnel performing inspections and repairs.
    b. Document the leak detection training using the test method specified in Section 6.4.1 for new operator, and for experienced operators, as necessary.
    c. The operator shall maintain copies of the training records at the facility. Copies of the training records shall be made available to the APCO, ARB, and US EPA upon request.

The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall submit an Operator Management Plan for approval to the APCO. The operator shall describe in the Operator Management Plan all components Subject to Rule 4455 or exempt pursuant to Subject 4.0. The plan shall contain a descriptions and procedures that the operator will use to comply with the requirements of Rule 4455. The Plan shall include, at a minimum, all of the following information: 1) Identification and description of any known hazard that might affect the safety of an inspector; 2) Diagrams, charts, spreadsheets, or other methods approved by the APCO which describe the following: 2a) Except for pipes, the number of components that are subject to Rule 4455 by component type and type of service (liquid or gas); 2b) Except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor* *components, critical components, and essential components that are subject to Rule 4455 including the reasons for such designation; 2c) Except for pipes, the location of components that are subject to this rule (components may be grouped together functionally by process unit or facility description; 2d) Except for pipes components exempt pursuant to Section 4.2 (except for components buried below ground) may be described by grouping them functionally by process unit or facility description. The results of any laboratory testing or other pertinent information to demonstrate compliance with the exemption criteria for components shall be submitted with the Operator Management Plan; 3) Detailed schedule of inspection to be conducted as required by Rule 4455; 4) Include the compliance plan for process pressure relief devices as required by Rule 4455; 5) Specify whether a qualified contractor or in-house team will perform inspections; 6) Establish an employee training program for inspecting, repairing, and recordkeeping procedures; 6a) Specify the training standards for personnel performing inspections and repairs; 6b) document the leak detection training using instruments in accordance with EPA Method 21. The operator shall maintain records of the Operator Management Plan and training records at the facility. Copies of such records shall be made available to the APCO, ARB, and US EPA upon request. [District Rule 4455]*

Section 6.1.4 states that by January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any changes to an existing Operator Management Plan. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *By January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any changes to the existing Operator Management Plan. [District Rule 4455]*

Section 6.1.5 states that the APCO shall provide written notice to the operator of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such plan. If the APCO fails to respond in writing within 60 days after the date of receiving the Plan, it shall be deemed approved. No provision of the Plan, approved or not, shall conflict with or take precedence over any provision of this Rule. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The District shall provide written notice of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such Plan. If the District fails to respond in writing within 60 days after the date of receiving the Plan, it shall be deemed approved. No provision of the Plan, approved or not, shall conflict with or take precedence over any provision of Rule 4455. [District Rule 4455]*

An operator at each facility shall maintain an inspection log containing the following:

1. Total number of components inspected, and total number and percentage of leaking components found by component types.
2. Location, type, name or description of each leaking component, and description of any unit where the leaking component is found.
3. Date of leak detection and method of leak detection.

4. For gaseous leaks, the concentration in ppmv, and for liquid leaks, whether the liquid leak is a major leak or a minor leak.
5. Date of repair, replacement, or removal from operation of leaking components.
6. Identification and location of essential component and critical components found leaking that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes earlier.
7. Methods used to minimize the leak from essential components and critical components that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes later.
8. After the component is repaired or replaced, the date of re-inspection and the leak concentration in ppmv.
9. Inspectors name, business mailing address, and business telephone number.
10. The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log.

The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall maintain an inspection log containing the following: 1) Total number of components inspected, and total number and percentage of leaking components found by component type; 2) Location, type, name or description of each leaking component, and description of any unit where the leaking component is found; 3) Date of leak detection and method of leak detection; 4) For gaseous leaks, the concentration in ppmv, and for liquid leaks, whether the liquid leak is a major leak (a visible mist or continuous flow of liquid that is not seal lubricant) or a minor leak (a liquid leak, except seal lubricant, that is not a major liquid leak and drips liquid at a rate of more than three drops per minute); 5) Date of repair, replacement, or removal from operation of leaking components; 6) Identification and location of essential component and critical components found leaking that cannot be repaired until the next process turnaround or not later than one year after leak detection, whichever comes earlier; 7) Methods used to minimize the leak from essential components and critical components that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes later; 8) After the component is repaired or replaced, the date of re-inspection and the leak concentration in ppmv; 9) Inspectors name, business mailing address, and business telephone number; and 10) The facility operator responsible for inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log. [District Rule 4455]*

Section 6.2.2 states that until June 30, 2024, records of leaks detected by quarterly or annual operator inspection and each subsequent repair and re-inspection shall be submitted to the APCO, ARB, or US EPA upon request. Section 6.2.3 states that after June 30, 2024, records of leaks detected by operator inspection and each subsequent repair and re-inspection shall be submitted to the APCO, ARB, or EPA upon request. The later requirement is more generic and will be included on the permits.

The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *Records of leaks detected by operator inspection and each subsequent repair and re-inspection shall be submitted to the APCO, ARB, or USA upon request. [District Rule 4455]*

Section 6.2.4 states that records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of the current calibration gas certification from the vendor of said calibration gas, analyzer reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of the current calibration gas certification from the vendor of said calibration gas, analyzer reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, caliber gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4455]*

Section 6.2.5 states that copies of all records required of this rule shall be retained for a minimum of five years after the date of an entry. Such records shall be made available to the APCO, ARB, or US EPA upon request. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *All records shall be retained for a minimum of five years and shall be made available to the District, ARB, or USEPA upon request. [District Rule 4455]*

Section 6.3.1 states that the operator shall notify the APCO, by telephone or other methods, approved by the APCO, of any process PRD release. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall notify the District, by telephone or other methods approved by the District, of any process pressure relief device release. [District Rule 4455]*

Section 6.3.2 states that the operator shall submit a written report to the APCO within thirty calendar days following notification of process PRD release. The written report shall include the following:

1. Process PRD type, size, and location.
2. Date, time and duration of process PRD release.
3. Types of VOC released and individual amounts, in pounds, including supporting calculations.
4. Cause of the process PRD release.
5. Corrective actions taken to prevent a subsequent PRD release.

The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall submit a written report to the District within 30 calendar days following the notification of a process pressure release device release. The report shall include the following: 1) Process pressure release device type, size and location; 2) Date, time, and duration of process pressure relief device release; 3) Types of VOC release and individual amounts, in pounds, including supporting calculations; 4) Cause of the pressure release device release; and 5) Corrective actions taken to prevent a subsequent pressure release device release. [District Rule 4455]*

Section 6.3.3 states that the operator shall keep records of the process parameters monitored for pressure release devices. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *The operator shall keep records of the process parameters monitored for pressure release devices. [District Rule 4455]*

Section 6.4.1 states that measurements of gaseous leak concentrations shall be conducted according to US EPA Method 21 using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with the procedures specified in US EPA Method 21 or the manufacturer's instructions, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. The following condition will be included on permits N-9742-20-0, '-21-0 and '-24-0:

- *Measurements of gaseous leak concentrations using EPA Method 21 shall be made using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with US EPA Method 21 or the manufacturer's instructions, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. [District Rule 4455]*

Section 6.4.1.1 states that after June 30, 2024, all leaks detected with the use of an OGI instrument shall be measured using EPA reference Method 21 within two calendar days of initial OGI leak detection or within 14 calendar days of OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in Table 5. The following condition will be included on permits N-9742-20-0, '-21-0, and '-24-0:

- *After June 30, 2024, all leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two calendar days of initial OGI leak detection, or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component do determine compliance with the leak thresholds and repair timeframes specified in Table 5 of Rule 4455. District Rule 4455]*

Compliance with the requirements of Rule 4455 is expected.

District Rule 4623 Storage of Organic Liquids

This rule applies to any tank with a capacity of 1,100 gallons or greater in which any organic liquid is place or held, and any tank in used in crude oil or natural gas production operations with a potential to emit of six tons of VOC or greater per year.

The slop tanks have a TVP greater than 0.1 psia. Therefore, the tanks will be subject to the requirements of District Rule 4623 beginning June 30, 2024. The requirements of District Rule 4623 will be included on the Authority to Construct permit.

The naphtha tanks have a TVP greater than 1.5 psia and less than 11 psia. Therefore, the naphtha tanks are subject to all the applicable requirements of District Rule 4623.

Each of the slop storage tanks has a capacity greater than 39,600 gallons and will have a true vapor pressure (TVP) between 0.1 and 0.5 psia. Pursuant to Table 4, the tanks are required to be equipped with an internal float roof, external floating roof, or a vapor recovery system. The proposed slop tanks are equipped with an internal floating roof; therefore, this requirement is satisfied.

Each of the naphtha storage tanks has a capacity greater than 39,600 gallons and will store organic liquid with a true vapor pressure (TVP) between 1.5 psia and 11 psia. Pursuant to Table 3 and Table 4, the tanks are required to have an internal floating roof, external floating roof, or a vapor recovery system. The proposed naphtha storage tanks have internal floating roofs; therefore, this requirement is satisfied.

Section 5.1.1.1 states that if a tank has a potential to emit greater than or equal to six tons of VOC per year and actual emissions are greater than or equal to four tons of VOC per year, the operator must install a vapor control system. The naphtha and slop storage tanks do not have a potential to emit greater than or equal to six tons of VOC per year; therefore, the use of a vapor recovery system is not required.

Section 5.1.3 states that all tanks subject to the control requirements of Rule 4623 must be maintained in a leak free condition, except for the following components and as allowed by Section 5.2 and applicable provisions of Table 5 through Table 7 and Section 5.7.5.4:

1. Primary and secondary seals of external floating roof tanks
2. Primary and secondary seals of internal floating roof tanks
3. Floating roof deck fittings
4. Floating roof automatic bleeder vents

The proposed naphtha and slop storage tank permits will include the definition of leaks and the leak requirements for the tanks.
Section 5.2 provides specifications for pressure-vacuum relief valves. Internal floating roof tanks are not equipped with pressure vacuum relief valves; therefore, this section is not applicable.

Section 5.3 provides specifications for external floating roof tanks. The requirements of this section do not directly apply to internal floating roof tanks.

Section 5.4 provides specifications for internal floating roof tanks. Section 5.4.1 states that internal floating roof tanks must meet the criteria of Section 5.3, except for complying with the requirement specified in Section 5.3.2.1.3. For internal floating roofs, the metallic-shoe type seals must be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 6 inches above the liquid surface. The proposed welded tanks will each be equipped with primary metallic-shoe type seals. The following requirements are applicable to the seals:

1. No gap between the tank shell and the primary seal shall exceed one and one half inches. The cumulative length of all gaps between the tank shell and the primary seal greater than one-half (1/2) inch shall not exceed ten (10) percent of the circumference of the tank. The cumulative length of all primary seal gaps greater than one-eighth inch must not exceed 30 percent of the tank circumference. No continuous gap greater than one eighth inch may exceed ten percent of the tank circumference.

2. No gap between the tank shell and the secondary seal may exceed one-half inch. The cumulative length of all gaps between the tank shell and the secondary seal, greater than one-eighth inch shall not exceed five percent of the tank circumference.

3. Metallic-shoe-type seals shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 6 inches above the stored liquid surface.

4. The geometry of the metallic-shoe-type seal must be such that the maximum gap between the shoe and the tank shelf is no greater than double the gap allowed by the seal gap criteria specified in Section 5.3.2.1.1 for a length of at least 18 inches in the vertical plane above the liquid surface.

5. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal.

6. The secondary seal must allow easy insertion of probes up to one and one-half inches in width in order to measure gaps in the primary seal.

7. The secondary seal must extend from the roof to the tank shell and must not be attached to the primary seal.

The following conditions will be included on each of the storage tank permits:

- *Gaps between the tank shell and the primary seal shall not exceed 1 1/2 inches. [District Rule 4623]*

- The cumulative length of all gaps between the tank shell and the primary seal greater than 1/2 inch shall not exceed 10% of the circumference of the tank. [District Rule 4623]

- *The cumulative length of all primary seal gaps greater than 1/8 inch shall not exceed 30% of the circumference of the tank. [District Rule 4623]*

- *No continuous gap in the primary seal greater than 1/8 inch wide shall exceed 10% of the tank circumference. [District Rule 4623]*

- *No gap between the tank shell and the secondary seal shall exceed 1/2 inch. [District Rule 4623]*

- *The cumulative length all gaps between the tank shell and the secondary seal, greater than 1/8 inch shall not exceed 5% of the tank circumference. [District Rule 4623]*

- *The metallic shoe-type seal shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 6 inches above the stored liquid surface. [District Rule 4623]*

- *The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell shall be no greater than 3 inches for a length of at least 18 inches in the vertical plane above the liquid. [District Rule 4623]*

- *There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. [District Rule 4623]*

- *The secondary seal shall allow easy insertion of probes of up to 1 1/2 inches in width in order to measure gaps in the primary seal. [District Rule 4623]*

- *The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. [District Rule 4623]*

Section 5.5.1 requires that all openings in the roof used for sampling or gauging, except pressure-vacuum relief valves, provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and must be equipped with a cover, seal, or lid. The cover, seal, or lid shall at all times be in a closed position, with no visible gaps and leak-free, except when the device or appurtenance is in use for sampling or gauging. The following condition will be included on each of the storage tank permits:

- *All openings in the roof used for sampling and gauging, except pressure-vacuum relief valves which shall be set to within 10% of the maximum allowable working pressure of the roof, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal or lid that shall be in a closed position at all times, with no visible gaps and be gas tight, except when the device or appurtenance is in use. [District Rule 4623]*

Section 5.5.2.1.1 states that each opening in a non-contact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents shall provide a projection below the liquid surface.

Section 5.5.2.1.2 states that each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, combination manway/vacuum breakers, and stub drains shall be equipped with a cover, or a lid shall be maintained in a closed position at all times (i.e., no visible gap) except when the device is in use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted in place except when they are in use.

Section 5.5.2.1.3 states that the automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the leg roof supports.

Section 5.5.2.1.4 states that rim vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or set to open at the manufacturer's recommended setting.

Section 5.5.2.1.5 states that each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90 percent of the opening. The fabric cover must be impermeable.

5.5.2.1.6 Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable.

The following conditions will be included on each of the storage tank permits to enforce the requirements of Sections 5.5.2.1.1 through 5.5.2.1.6.

- *Each opening in a non-contact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents shall provide a projection below the liquid surface. [District Rule 4623 and 40 CFR 60.112b(a)(1)(iii)]*

- *Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains shall be equipped with a cover, or a lid shall be maintained in a closed position at all times (i.e. no visible gaps) except when the device is in use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted in place except when they are in use. [District Rule 4623 and 40 CFR 60.112b(a)(1)(iv)]*

- *Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the leg roof supports. [District Rule 4623 and 40 CFR 60.112b(a)(1)(v)]*

- *Rim vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. [District Rule 4623 and 40 CFR 60.112b(a)(1)(vi)]*

- *Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90 percent of the opening. The fabric cover must be impermeable. [District Rule 4623 and 40 CFR 60.112b(a)(1)(vii)]*

- *Each penetration of the internal floating roof that allows for the passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable. [District Rule 4623 and 40 CFR 60.112b(a)(1)(viii)]*

Section 5.5.2.4.1 states that slotted sampling and gauging wells must provide a projection below the liquid surface.

Section 5.5.2.4.3 states that the gap between the pole wiper and the guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement and in no case shall exceed one eighth inch.

The following conditions will be included on each of the storage tank permits:

- *All slotted sampling or gauging wells shall provide a projection below the liquid surface. [District Rule 4623]*

- *The gap between the pole wiper and the slotted guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement and in no case shall exceed one-eighth inch. [District Rule 4623]*

Section 5.6 includes specifications for vapor recovery systems. The proposed tanks will not be equipped with vapor recovery systems; therefore, this section is not applicable.

Section 5.7.5 lists the storage tank degassing and interior cleaning requirements. These requirements apply to the naphtha and the slop storage tanks. Section 5.7.5.1 states that the operators of storage tanks must notify the APCO in writing at least 3 days prior to performing tank degassing and interior tank cleaning activities. Written notification must include the following:

- The PTO number and physical location of the tank being degassed.
- The date and time that tank degassing and cleaning activities will begin.
- The degassing method, as allowed pursuant to Section 5.7.5.4, to be used.
- The method used to clean the tank, including any solvents to be used, and
- The method to be used to dispose of the removed sludge including methods that will be used to control emissions during transport.

The following condition will be included on each of the storage tank permits:

- *The owner or operator shall notify the APCO in writing at least three days prior to performing tank degassing and interior tank cleaning activities. The written notification shall include the following: 1) The PTO number and physical location of the tank being degassed, 2) The date and time that tank degassing and cleaning activities will begin, 3) The degassing method to be used, 4) The method that will be used to clean the tank, including any solvents to be used, and 5) The method to be used to dispose of the removed sludge including methods that will be used to control emissions during transport. [District Rule 4623]*

Section 5.7.5.2 states that operators must maintain records of tank cleaning activities for a period of 5 years and present said records to the APCO upon request. The following condition will be included on each of the storage tank permits:

- *The operator shall maintain records of tank cleaning activities for a period of 5 years and present said records to the APCO upon request. [District Rule 4623]*

Section 5.7.5.3 is only applicable to fixed roof tanks and is not applicable to the proposed internal floating roof storage tanks.

Section 5.7.4.1 states that the operator shall minimize organic vapors in the tank vapor space by one of the following methods during tank degassing:

- Exhaust VOCs contained in the tank vapor space to an APCO-approved vapor recovery system until the organic vapor concentration is 5,000 ppmv or less, or is 10 percent or less of the lower explosion limit (LEL), whichever is less; or
- Displace VOCs contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable liquid until 90 percent or more of the maximum operating level of the tank is filled. Suitable liquids are organic liquids having a TVP of less than 0.1 psia, water, clean produced water, or produced water derived from crude oil having a TVP less than 0.5 psia; or
- Displace VOC contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable gas. Degassing shall continue until the operator has achieved a vapor displacement equivalent to at least 2.3 times the tank capacity. Suitable gases are air, nitrogen, carbon dioxide, or natural gas containing less than 10 percent VOC by weight; or
- For free-water knockout tanks, the operator may degas the tank vapor space by restricting the outflow of water and floating off the oilpad, such that at least 90 percent of the tank volume is displaced.

The following condition will be included on each of the storage tank permits:

- *The process of tank degassing shall be accomplished by emptying the tank of organic liquid having a TVP of 0.1 psia or greater and minimizing organic vapors in the tank vapor space by one of the following methods: 1) Exhaust VOCs contained in the tank vapor space to an APCO-approved vapor recovery system until the organic vapor concentration* *is 5,000 ppmv or less, or is 10 percent or less of the lower explosion limit (LEL), whichever is less; or 2) Displace VOCs contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable liquid until 90 percent or more of the maximum operating level of the tank is filled. Suitable liquids are organic liquids having a TVP of less than 0.1 psia, water, clean produced water, or produced water derived from crude oil having a TVP less than 0.5 psia; or 3) Displace VOC contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable gas. Degassing shall continue until the operator has achieved a vapor displacement equivalent to at least 2.3 times the tank capacity. Suitable gases are air, nitrogen, carbon dioxide, or natural gas containing less than 10 percent VOC by weight. [District Rule 4623]*

Section 5.7.5.4.5 states that during degassing, the operator must discharge or displace organic vapors contained in the tank vapor space to an APCO-approved vapor recovery system that is leak-free and routes vapors to one of the following VOC control devices:

1. A condensation or vapor return system that connects to one of the following: a gas processing plant, a field gas pipeline, a pipeline distribution PUC quality gas for sale, an injection well for disposal of vapors as approved by the California Geological Energy Management Division (CalGEM); or
2. A VOC control device that reduces the inlet VOC emissions by at least 95 percent by weight.

VOC control option #1 is not available to this site. The following condition will be included on each of the storage tank permits:

- *During degassing, the operator shall discharge or displace organic vapors contained in the tank vapor space to an APCO-approved vapor recovery system that is leak free and routes vapors to a VOC control device that reduced the inlet VOC emissions by at least 95 percent by weight. [District Rule 4623]*

Section 5.7.5.4.6 states that to facilitate connection to an external APCO-approved vapor recovery system, a suitable fitting, such as a manway, may be temporarily removed for a period of time not to exceed 1 hour. The following condition will be included on each of the storage tank permits:

- *To facilitate connection to an external APCO-approved vapor recovery system during degassing, a suitable fitting such as a manway may be temporarily removed for a period of time not to exceed 1 hour. [District Rule 4623[*

Section 5.7.5.4.7 states that the tank must be in compliance with the applicable requirements specified in Section 5.1 through Section 5.6 during draining, degassing, and refilling the tank. The following condition will be included on each of the storage tank permits:

- *This tank shall be in compliance with the applicable requirements of District Rule 4623 at all times during draining, degassing, and refilling the tank with an organic liquid having a TVP of 0.1 psia or greater. [District Rule 4623]*

Section 5.7.5.4.8 states that draining and refilling of floating roof tanks must occur as a continuous process and shall proceed as rapidly as practicable while the roof is not floating on the surface of the stored liquid. The following condition will be included each of the storage tank permits:

- *During tank cleaning operations, draining and refilling of this tank shall occur as a continuous process and shall proceed as rapidly as practicable while the roof is not floating on the surface of the stored liquid. [District Rule 4623]*

Pursuant to Section 5.7.5.4.9, for floating roof tanks the gap seal requirements specified in Sections 5.3.2 and 5.4.2 do not apply while the roof is resting on its legs, and during the processes of draining, degassing, or refilling the tank. The leak-free condition specified in Section 5.1.3 does not apply during refilling of the tank. The following condition will be included on each of the storage tank permits:

- *Gap seal requirements shall not apply while the roof is resting on its legs, and during the processes of draining, degassing, or refilling the tank. A leak-free condition will not be required if the operator is draining or refilling this tank in a continuous, expeditious manner. [District Rule 4623]*

Section 5.7.5.4.10 states that after a tank has been degassed, the requirements of Sections 5.1 through 5.6 do not apply until an organic liquid of TVP of 0.1 psia or greater is placed, held, or stored in the tank. The following condition will be included on each of the storage tank permits:

- *After a tank has been degassed pursuant to the requirements of this permit, vapor control requirements are not applicable until an organic liquid having a TVP of 0.1 psia or greater is placed, held, or stored in this tank. [District Rule 4623] Y*

Section 5.5.5.5.1 states that while performing tank cleaning activities, operators may use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 °F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams per liter of VOC content or less. Section 5.7.5.5.2 states that steam cleaning is allowed in locations where wastewater treatment facilities are limited or during the months of December through March.

The following conditions will be included on each of the storage tank permits:

- *While performing tank cleaning activities, operators may only use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 degrees F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams of VOC per liter or less. [District Rule 4623]*

- *Steam cleaning shall only be allowed at locations where wastewater treatment facilities are limited, or during the months of December through March. [District Rule 4623]*

Section 5.7.5.6 states that operators of tanks containing an organic liquid with a TVP of 1.5 psia or greater must control emissions from the removed sludge by complying with the following:

1. During sludge removal, the operator shall control emissions from the receiving vessel by operating an APCO-approved vapor control device that reduces emissions of organic vapors by at least 95 percent.
2. Operators shall transport removed sludge in closed, liquid leak-free containers.
3. Operators shall store removed sludge, until final disposal, in leak-free containers or tanks complying with Section 5.1 requirements.

The following conditions will be included on the naphtha storage tank permits only:

- *During sludge removal, the operator shall control emissions from the sludge receiving vessel by operating an APCO-approved vapor control device that reduces emissions of organic vapors by at least 95%. [District Rule 4623]*

- *The permittee shall only transport removed sludge in closed, liquid leak-free containers. [District Rule 4623]*

- *The permittee shall store removed sludge, until final disposal, in vapor leak-free containers, or in tanks complying with the vapor control requirements of District Rule 4623. Sludge that is to be used to manufacture roadmix, as defined in District Rule 2020, is not required to be stored in this manner. Roadmix manufacturing operations exempt pursuant to District Rule 2020 shall maintain documentation of their compliance with Rule 2020, and shall readily make said documentation available for District inspection upon request. [District Rules 2020 and 4623]*

Section 5.9.1 states that for the purpose of this rule, a facility is considered to be in violation if one or more of the conditions specified below exist at the facility during District inspection:

1. The discovery of a major gas leak greater than 10,000 ppmv.
2. The discovery of a liquid leak as defined in Section 3.23.
3. Exceeding the allowable number of minor leaks as defined in Table 8 of Rule 4623.
4. Failure to repair leaks as specified within the timeframes specified in Table 9.

The facility has proposed to comply with more stringent leak requirements of 100 ppmv for valves and flanges, and 500 ppmv for compressor seals and pumps. A condition enforcing these more stringent requirements was included earlier in this evaluation.

Section 5.9.2 states that a facility shall be considered in violation during operator inspections for failure to repair leaks within the timeframes specified in Table 9.
Section 5.9.3 gives a timeframe of 14 days to repair a gas leak up to 10,000 ppmv, 2 days to repair a gas leak greater than 10,000 ppmv, and 2 days to repair a liquid leak. The following condition will be included on the storage tank permits:

- *A leak discovered during operator or District inspection shall be repaired within the following timeframes: within 14 calendar days of discovery for gas leaks less than or equal to 10,000 ppmv, within 2 calendar days of discovery for gas leaks greater than 10,000 ppmv, and within 2 calendar days of discovery for liquid leaks. [District Rule 4623]*

Section 5.9.4 states that at least once each calendar quarter all components shall be tested for leaks except for inaccessible components, unsafe to monitor components and floating roof tanks including their deck fittings and components. Internal floating roof tanks must be inspected once every 60 months as required by Section 6.1.4.

Inspections shall be performed as allowed by the following:

1. All components shall be tested for leaks of total hydrocarbons in units of parts per million volume (ppmv) in accordance with US EPA Reference Method 21.
2. Inaccessible components and unsafe-to-monitor components shall be inspected once every 12 months per US EPA Reference Method 21.
3. Except for inaccessible components, unsafe to monitor components, and floating roof tanks including deck fittings and components, owners or operators shall audio-visually inspect (by hearing and sight) all hatches, pressure vacuum relief valves, pressure relief devices, and pump seals for leaks or indications or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours.
4. Any audio-visual inspection specified that indicates a leak shall be tested using EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance with the timeframes in Table 9.
5. An operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 24 hours, and leaks shall be repaired in the timeframes specified in Table 9.
6. A District inspection in no way fulfills any of the mandatory inspection requirements that are placed upon operators and cannot be used or counted as an inspection required by the operator.
7. Upon detection of a component with a leak concentration measured above the standards specified, the owner or operator must affix to that component a weatherproof readily visible tag that identifies the date and time of leak detection measurement and the measured leak concentration. The tag shall remain affixed to the leaking component until it has been successfully repaired or replaced, after which the tag shall be removed. Successful repair shall be confirmed by re-measuring the components using EPA Reference Method 21 to determine that the component is below the minimum leak threshold after repair or replacement.
8. Excluding tanks, components or component parts which incur five repair actions within a rolling 12-month period shall be replaced with a compliant component in working order and must be re-measured using US EPA Reference Method 21, to determine that the component is below the minimum leak threshold. A record of the replacement must be maintained in a log at the facility, and shall be made available upon request to the APCO.
9. An operator shall attempt to minimize all component leaks immediately to the extent possible, but no later than one hour after detection of leak in order to stop or reduce leakage to the atmosphere.
10. If the leak has been minimized but the leak still exceeds the applicable leak standards of this rule, an operator shall comply with at least one of the following as soon as practicable, but no later than the time period specified in Table 9:
    a. Repair or replace the leaking component; or

b. Vent the leaking component to a VOC control system
c. Remove the leaking component from operation.

The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in Table 9. The start of the repair period shall be the time of the initial leak detection.

The following conditions will be included on the storage tank permits:

- *The operator shall perform periodic component leak inspections once each calendar quarter, except for inaccessible components, unsafe to monitor components and floating roof tanks including their deck fittings and components. Internal floating roof tanks shall be inspected once every 60 months. [District Rule 4623]*

- *For periodic component leak inspections, all components shall be tested for leaks of total hydrocarbons in units of parts per million volume (ppmv) in accordance with US EPA Reference Method 21. [District Rule 4623]*

- *For periodic component leak inspections, inaccessible components and unsafe to monitor components shall be inspected once every 12 months per US EPA Reference Method 21. [District Rule 4623]*

- *For periodic component leak inspections, except for inaccessible components, unsafe to monitor components, and floating roof tanks including deck fittings and components, owners or operators shall audio-visually inspect (by hearing and sight) all hatches, pressure-vacuum relief valves, pressure relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours. [District Rule 4623]*

- *For periodic component leak inspections, any audio-visual inspection specified that indicates a leak shall be tested using EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance the leak repair timeframes specified within this permit [District Rule 4623]*

- *For periodic component leak inspections, an operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 24 hours, and leaks shall be repaired in accordance the leak repair timeframes specified within this permit. [District Rule 4623]*

- *A District inspection does not fulfill the periodic component leak inspection requirements and cannot be used or counted as an inspection required of the operator. [District Rule 4623]*

- *For periodic leak inspections, upon detection of a component with a leak concentration measured above the limits in this permit, the operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of the leak detection* *measurement and the measured leak concentration. The tag shall remain affixed to the leaking component until it has been successfully repaired or replaced, after which the tag shall be removed. Successful repair shall be confirmed by re-measuring the components using EPA Reference Method 21 to determine that the component is below the minimum leak threshold after repair or replacement. [District Rule 4623]*

- *For periodic leak inspections, excluding tanks, components or component parts which incur five repair actions within a rolling 12-month period shall be replaced with a compliant component in working order and must be re-measured using EPA Reference Method 21, to determine that the component is below the minimum leak threshold. A record of the replacement shall be maintained in a log at the facility, and shall be made available upon request to the APCO. [District Rule 4623]*

- *For periodic leak inspections, the operator shall attempt to minimize all component leaks to the extent possible immediately after detection, but no later than one hour after detection of the leak in order to stop or reduce leakage to the atmosphere. [District Rule 4623]*

- *For periodic leak inspections, if the leak has been minimized but the leak still exceeds the applicable leak standards in this permit, the operator shall comply with at least one of the following as soon as practicable, but no later than the time period for repairing the leak as specified in this permit: 1) Repair or replace the leaking component; or 2) Vent the leaking component to a VOC control system as defined in Section 3.1 of District Rule 4623 (6/15/23); or 3) Remove the leaking component from operation. [District Rule 4623]*

- *For periodic leak inspections, the leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in this permit. The start of the repair period shall be the time of the initial leak detection. [District Rule 4623]*

Section 6.1.1 lists requirements for external floating roof tanks. Since the applicant is not proposing any tanks with external floating roofs, this section is not applicable.

Section 6.1.2 states that operators of floating roof tanks shall submit a tank inspection plan to the APCO for approval. The plan shall include an inventory of the tanks subject to this rule and a tank inspection schedule. A copy of the operator's tank safety procedures shall be made available to the APCO upon request. The tank inventory shall include tank's identification number, PTO number, maximum tank capacity, dimensions of tank (height and diameter), organic liquid stored, type of primary and secondary seal, type of floating roof (internal or external floating roof), construction date of tank, and location of tank. Any revision to a previously approved tank inspection schedule shall be submitted to the APCO for approval prior to conducting an inspection. The following condition will be included on each of the storage tank permits:

- *The owner or operator shall submit a tank inspection plan to the APCO for approval. The plan shall include an inventory of the tanks subject to this rule and a tank inspection schedule. A copy of the operator's tank safety procedures shall be made available to the*

APCO upon request. The tank inventory shall include tank's identification number, PTO number, maximum tank capacity, dimensions of tank (height and diameter), organic liquid stored, type of primary and secondary seal, type of floating roof (internal or external floating roof), construction date of tank, and location of tank. Any revision to a previously approved tank inspection schedule shall be submitted to the APCO for approval prior to conducting an inspection. [District Rule 4623]

Section 6.1.3 is applicable to external floating roof tanks. Since none of the proposed tanks have an external floating roof, this section is not applicable.

Section 6.1.4.1 states that for newly constructed, repaired, or rebuilt internal floating roof tanks, visually inspect the internal floating roof and its appurtenant parts, fittings, etc., and measure the gaps of the primary seal and/or secondary seal prior to filling the tank. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., the operator shall repair the defects before filling the tank.

6.1.4.2 states that the owner or operator must visually inspect, through the manholes, roof hatches, or other openings on the fixed roof, the internal floating roof and its appurtenant parts, fittings, etc., and the primary seal and/or secondary seal at least once every 12 months after the tank is initially filled with an organic liquid. There should be no visible organic liquid on the roof, tank walls, or anywhere. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of hydrocarbon vapors. Any defects found are violations of this rule.

6.1.4.3 states that the owner or operator must conduct actual gap measurements of the primary seal and/or secondary seal at least once every 60 months. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of hydrocarbon vapors. Any defects found shall constitute a violation of this rule.

The following conditions will be included on each tank permit:

- *For newly constructed, repaired, or rebuilt internal floating roof tanks, the permittee shall visually inspect the internal floating roof, and its appurtenant parts, fittings, etc. and measure the gaps of the primary seal and/or secondary seal prior to filling the tank for newly constructed, repair, or rebuilt internal floating roof tanks. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to filling the tank. [District Rule 4623 and 40 CFR 60.113b(a)(1)]*

- *The operator shall visually inspect, through the manholes, roof hatches, or other opening on the fixed roof, the internal floating roof and its appurtenant parts, fittings, etc., and the primary seal and/or secondary seal at least once every 12 months after the tank is initially filled with an organic liquid. There should be no visible organic liquid on the roof, tank walls, or anywhere. Other than the gap criteria specified by this rule, no holes, tears, or* *other openings are allowed that would permit the escape of vapors. Any defects found are violations of this rule. [District Rule 4623 and 40 CFR 60.113b(a)(2)]*

- *The permittee shall conduct actual gap measurements of the primary seal and/or secondary seal at least once every 60 months. Other than the gap criteria specified by this permit, no holes, tears, or other openings are allowed that would permit the escape of hydrocarbon vapors. Any defects found shall constitute a violation of Rule 4623. [District Rule 4623]*

Section 6.2 lists TVP and API gravity testing for uncontrolled fixed roof storage tanks. The applicant has not proposed any fixed roof storage tanks; therefore, this section is not applicable.

Sections 6.3.1 through 6.3.4 are not applicable to the proposed tanks since the facility is not a small producer, the tanks are not emergency standby tanks, the tanks are not temporary tanks, and since the tanks have an internal floating roof.

Section 6.3.5 states that the operator shall submit the reports of the floating roof tank inspections conducted in accordance with the requirements of Section 6.1 to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Sections 5.2 through 5.5. The inspection report for tanks that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and shall be made available upon request by the APCO. The inspection report shall contain all information necessary to demonstrate compliance with the provisions of this rule, including the following:

1. Date of inspection and names and titles of company personnel doing the inspection.
2. Tank identification numbers and PTO number.
3. Measurements of the gaps between the tank shell and primary and secondary seals.
4. Leak-free status of tanks and floating roof deck fittings. Records of leak-free status shall include the vapor concentration values measured in ppmv.
5. Data supported by calculations demonstrating compliance with the requirements specified in Rule 4623.
6. Any corrective actions or repairs performed on the tank in order to comply with this rule and the date such actions were taken.

The following condition will be included on each tank permit:

- *The permittee shall submit the reports of the floating roof tank inspections to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Rule 4623, Sections 5.2 through 5.5. The inspection report for tanks that that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the* *inspection report shall be kept on-site and made available upon request by the APCO. The inspection report shall contain all necessary information to demonstrate compliance with the provisions of this rule, including the following: 1) Date the storage vessel was emptied, date of inspection and names and titles of company personnel doing the inspection. 2) Tank identification number and Permit to Operate number. 3) Observed condition of each component of the control equipment (seals, internal floating roof, and fittings). 4) Measurements of the gaps between the tank shell and primary and secondary seals. 5) Leak free status of the tank and floating roof deck fittings. Records of the leak-free status shall include the vapor concentration values measured in parts per million by volume (ppmv). 6) Data, supported by calculations, demonstrating compliance with the requirements specified in Sections 5.4 and 5.5.2.4.3 of Rule 4623. 7) Nature of defects and any corrective actions or repairs performed on the tank in order to comply with rule 4623 and the date(s) such actions were taken. [District Rule 4623 and 40 CFR 60.115b(a)]*

Section 6.3.6 is not applicable, since the units are not subject to the TVP and API gravity testing requirements of Section 6.2.

Section 6.3.7 requires the operator to maintain the records of the external floating roof or internal floating roof landing activities that are performed pursuant to Sections 5.3.1.3 and 5.4.3. The records shall include information on the TVP, API gravity, and type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. The operator shall keep the records at the facility (or on-site) for a period of five years. The records shall be made available to the APCO upon request.

The following condition will be included on each tank permit:

- *The permittee shall maintain the records of the internal floating roof landing activities that are performed pursuant to Rule 4623, Section 5.3.1.3 and 5.4.3. The records shall include information on the TVP, API gravity, and type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. [District Rule 4623]*

Section 6.3.8 states that an operator that is demonstrating their tank PTE emissions are below 6 tons of VOC per year or actual emissions are below 4 tons of VOC per year shall keep an accurate record of each organic liquid stored in each tank, including storage temperature, TVP, and monthly throughput. The following condition will be included on each tank permit:

- *The operator shall keep an accurate record of each organic liquid stored in the tank, including storage temperature, TVP, and monthly throughput. [District Rule 4623]*

Section 6.3.9 states that the operator shall maintain an inspection log containing, at a minimum, all of the following:

1. Total number of components inspected and total number and percentage of leaking components found during inspection.
2. Location, type, name or description of each leaking component and description of any unit where the leaking component is found.
3. Date of leak detection and method of leak detection.
4. For gas leaks, record the leak concentration in ppmv, and for liquid leaks record the volume.
5. Date of repair, replacement, or removal from operation of leaking components.
6. After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv.
7. Inspector's name, business mailing address, and business telephone number.
8. The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log.
9. Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration.
10. Copies of all records required by Section 6.3 of this rule shall be retained for a minimum of five years after the date of an entry and the records shall be made available to the APCO, CARB, and US EPA upon request.

The following condition will be included on each tank permit:

- *The operator shall maintain an inspection log containing, at a minimum, the following: 1) Total number of components inspected and total number and percentage of leaking components found during inspection; 2) Location, type, name, or description of each leaking component and description of any unit where the leaking component is found, 3) Date of leak detection and method of leak detection, 4) For gas leaks, record the leak concentration in ppmv, and for liquid leaks record the volume, 5) Date of repair, replacement, or removal from operation of leaking components, 6) After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv, 7) Inspector's name, business mailing address, and business telephone number, 8) The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log, 9) Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components including a copy of the gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4623]*

Section 6.4.8 requires measurements of gas-leak concentration be determined using US EPA Method 21. This method has been included in the proposed permit conditions, where appropriate.

Compliance with District Rule 4623 requirements is expected.

District Rule 4624 Transfer of Organic Liquid

The purpose of this rule is to limit VOC emissions from the transfer of organic liquids. This rule is applicable to organic liquid transfer facilities. Organic liquid is defined in the Rule as *any liquid which contains VOCs and has a TVP of 1.5 psia or greater at the storage container's maximum organic liquid storage temperature*. The vegetable oil feedstock, animal fat feedstock, renewable diesel, and sustainable aviation fuel will have a TVP less than 1.5 psia. However, the facility will transfer naphtha throughout the year to assist in facility operations, and naphtha has a TVP greater than 1.5 psia. Therefore, the requirements of the Rule are applicable to the facility.

The quantity of naphtha transferred may exceed 20,000 gallons or more on any one day; therefore, the proposed operation will be considered to be a Class 1 Organic Liquid Transfer Facility.

Section 5.1 states that for a class 1 organic liquid transfer facility, the emission of VOC from the transfer operation may not exceed 0.08 per 1,000 gallons of organic liquid transferred and use one of the following systems:

1. An organic liquid loading operation must be bottom loaded.

2. The VOC from the transfer operation must be routed to:

    a. A vapor collection and control system;
    b. A fixed roof container that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids)
    c. A floating roof container that meets the control requirements specified in Rule 4623
    d. A pressure vessel equipped with an APCO approved vapor recovery system that meets the control requirements specified in Rule 4623 (Storage of Organic Liquids); or
    e. A closed VOC emission control system.

For this facility, naphtha is transferred into tanks with floating roofs that meet the control requirements specified in Rule 4623. The transfer of any organic liquids to railcars or trucks is controlled using a vapor collection system routed to a regenerative thermal oxidizer. The facility has proposed to meet BACT requirements for the organic liquid loading rack, which limits emissions to a more stringent limit of 0.015 pounds per 1000 gallons of organic liquid loaded. Therefore, the following conditions will be included on the material transfer permit:

- *Organic liquid loading operations shall be bottom loaded (submerged pipe fill loading). [District Rules 2201 and 4624]*

- *VOC emissions from organic liquid loading operations shall not exceed 0.015 pound per 1,000 gallons of organic liquid loaded. [District Rules 2201 and 4624]*

Section 5.3 states that an operator utilizing a closed VOC emission control system or utilizing a container that meets the control requirements of Rule 4623 must demonstrate compliance with

Sections 5.1 and 5.2 by complying with the leak inspection requirements of Section 5.9. This operation utilizes containers that meet the control requirements of Rule 4623 to demonstrate compliance with Sections 5.1 and 5.2. The leak inspection requirements of Section 5.9 are applicable and will be discussed later in this evaluation.

Section 5.4 states that a vapor collection and control system must operate such that the pressure in the delivery tank being loaded does not exceed eighteen inches water column pressure and six inches water column vacuum. The following condition will be included on the material transfer permit:

- *The vapor collection and control system associated with this permit shall operate such that the pressure in the delivery tank being loaded does not exceed 18 inches water column pressure and 6 inches water column vacuum. [District Rule 4624]*

Section 5.5 states that all delivery tanks that previously contained organic liquids with a TVP of 1.5 psia or greater at the storage container's maximum organic liquid storage temperature must be filled only at transfer facilities satisfying Sections 5.1, 5.2, or 5.4 of this rule, as applicable. The transfer facilities at this site all comply with the applicable requirements of Sections 5.1, 5.2, and 5.4 (as applicable) and the relevant requirements of these sections have been included on the material transfer permit. Thus, compliance with this requirement is expected.

Section 5.6 states that transfer rack and vapor collection equipment must be designed, installed, and maintained such that there are no leaks and no excess liquid drainage at disconnect. The applicant has proposed to comply with the requirements of BACT, which include the use of dry break couplers. The following condition will be included on the material transfer permit:

- *The loading rack(s) shall be equipped with dry break couplers and the transfer rack and vapor collection system shall be designed such that there are no leaks and no excess liquid drainage at disconnect. [District Rules 2201 and 4624]*

Section 5.7 states that new top-loading facilities are not allowed. The applicant is not proposing a top-loading facility.

Section 5.8 applies to facilities that exclusively transfer liquefied petroleum gas and does not apply to the proposed operation.

Section 5.9 lists leak inspection requirements as follows:

1. The operator of an organic liquid transfer facility must inspect the vapor collection system, the vapor disposal system, and each transfer rack handling organic liquids for leaks during transfer at least once every calendar quarter using a method described in Section 6.3.8.

2. A floating roof container that meets the applicable control requirements of Section 5.0 of Rule 4623 shall be considered not leaking for the purposes of this section.

3. All equipment that are found leaking shall be repaired or replaced within 72 hours. If the leaking component cannot be repaired or replaced within 72 hours, the component shall be taken out of service until such time the component is repaired or replaced. The repaired or replaced equipment shall be re-inspected the first time the equipment is in operation after the repair or replacement.

4. Until June 30, 2024, an operator may apply for a written approval from the APCO to change the inspection frequency from quarterly to annually provided no leaks were found for the past five consecutive quarterly inspections. Upon identifying any leak during an annual inspection, the frequency would revert to quarterly and the operation must contact the APCO in writing within 14 days. The facility is not expected to finish construction until after June 30, 2024; therefore, this provision will not be included on the permit for the material transfer operation.

5. After June 30, 2024, an operator is in violation if exceeding the allowable number of leaks during a District inspection (minor leaks 2% of number inspected, and major leaks 0). The applicant has proposed more stringent leak thresholds than required by District Rule 4624 and any leak above these thresholds will be considered a violation; therefore, this provision will not be included on the material transfer operation permit.

6. Except for inaccessible components and unsafe to monitor components, owners or operators must audio-visually inspect (by hearing and by sight) all hatches, pressure-relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least 24 hours. Owners or operators shall audio-visually inspect all pipes for leaks ore indications of leaks at least once every 12 months.

7. Any audio-visual inspection specified in Section 5.9.6 that indicates a leak shall be tested using US EPA Reference Method 21 within 24 hours, and the leak shall be prepared in accordance with the repair timeframes specified in Section 5.9.3.

The following conditions will be included on the material transfer permit:

- *The operator of an organic liquid transfer facility must inspect the vapor collection system and vapor disposal system, and each transfer rack handling organic liquids for leaks during transfer at least once every quarter using a portable hydrocarbon detection instrument in accordance with EPA Method 21. [District Rule 4624]*

- *All equipment that are found leaking shall be repaired or replaced within 72 hours. If the leaking component cannot be repaired or replaced within 72 hours, the component shall be taken out of service until such time the component is repaired or replaced. The repaired or replaced equipment shall be re-inspected the first time the equipment is in operation after the repair or replacement. [District Rule 4624]*

- *Except for inaccessible components and unsafe to monitor components, the owner or operator shall audio-visually inspect (by hearing and by sight) all hatches, pressure-relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for* *facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours. Owners or operators shall audio-visually inspect all pipes for leaks or indications of leaks at least once every 12 months. [District Rule 4624]*

- *Any component with an audio-visual inspection that indicates a leak shall be tested using US EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance with the repair timeframes specified in this permit. [District Rule 4624]*

Section 5.10.1 states that upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag.

Section 5.10.2 states that the tag shall remain affixed to the component until all of the following conditions are met:

1. The leaking component has been successfully repaired or replaced
2. The component has been re-inspected using the test method in Section 6.3.8
3. The component is found to be in compliance with the requirements of Rule 4624

Section 5.10.3 states that the tag shall contain the following information:

1. Date and time of leak detection
2. Date and time of leak measurement
3. For gaseous leaks, indicate the leak concentration in ppmv
4. For liquid leaks, the dripping rate of the liquid

The following condition will be included on the material transfer permit:

- Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag. The tag shall include 1) Date and time of leak detection, 2) Date and time of leak measurement, 3) For gaseous leaks, the leak concentration in ppmv, and 4) for liquid leaks, the dripping rate of the liquid. The tag shall remain affixed to the component until all of the following conditions are met: 1) The leaking component has been repaired or replaced, 2) The component has been re-inspected using a portable hydrocarbon detection instrument in accordance with EPA Method 21, and 3) The component is found to be in compliance with the requirements of District Rule 4624. [District Rule 4624]

Section 6.1.3 states that an operator subject to any part of Section 5.0 shall keep records of the daily liquid throughput and the results of any required leak inspections. Section 6.1.4 states that records shall be retained for a minimum of five years and shall be made readily available to the APCO, ARB, or EPA upon request. The following conditions will be included on the material transfer permit:

- *The operator shall keep records of the daily liquid throughput and the results of any required leak inspections. [District Rule 4624]*

- *All records shall be retained for a minimum of five years and shall be made readily available to the APCO, ARB, or EPA upon request. [District Rule 4624]*

Section 6.1.6 requires the operator to maintain an inspection log containing, at a minimum, all of the following information:

1. Total number of components inspected and total number and percentage of leaking components found during inspection.
2. Location, type, name or description of each leaking component and description of any unit where the leaking component is found.
3. Date of leak detection and method of leak detection.
4. For gaseous leaks, record the leak concentration in ppmv, and for liquid leaks record the volume.
5. Date of repair, replacement, or removal from operation of leaking components.
6. After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv.
7. Inspector's name, business mailing address, and business telephone number.
8. The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log.
9. Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components including a copy of current calibration gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration.
10. Copies of all records required by Section 6.3 of this rule shall be retained for a minimum of five years after the date of an entry and the records shall be made available to the APCO, CARB, and US EPA upon request.

The following condition will be included on the material transfer permit:

- *The operator shall maintain an inspection log containing, at a minimum, the following: 1) Total number of components inspected and total number and percentage of leaking components found during inspection; 2) Location, type, name, or description of each leaking component and description of any unit where the leaking component is found, 3) Date of leak detection and method of leak detection, 4) For gas leaks, record the leak concentration in ppmv, and for liquid leaks record the volume, 5) Date of repair, replacement, or removal from operation of leaking components, 6) After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv, 7) Inspector's name, business mailing address, and business telephone number, 8) The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log, 9) Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components including a copy of the gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4624]*

Section 6.2.1 states that the operator of a Class 1 or Class 2 organic liquid transfer facility shall perform an initial source test of the VOC emission control system using 40 CFR 60.503 "Test Methods and Procedures" and EPA Methods 2A, 2B, 25A an 25B and ARB Method 422, or ARB Test Procedure TP-203.1.

Section 6.2.2 states that the operator of any Class 1 or Class 2 organic liquid transfer facility shall perform a source test once every 60 months, but not more than 30 days before or after the initial source test anniversary date.

The following condition will be included on the material transfer permit:

- *Source testing to demonstrate compliance with the VOC limit (lb/1000 gal) and the VOC control efficiency shall be performed within 60 days of startup and at least once every 60 months thereafter. Source testing shall be performed using 40 CFR 60.503 "Test Methods and Procedures" and EPA Methods 2A, 2B, 25A and 25B and ARB Method 422, or ARB Test Procedure TP-203.1. [District Rules 2201 and 4624]*

Compliance with the requirements of this Rule is expected.

District Rule 4691 Vegetable Oil Processing Operations

The provisions of this rule are applicable to vegetable oil plants. A vegetable oil plant is defined as any facility engaged in the extraction or refining of vegetable oil. This facility does not extract or refine vegetable oil; therefore, the requirements of this Rule are not applicable.

District Rule 4701 Internal Combustion Engines – Phase 1

The purpose of this rule is to limit the emissions of nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion engines. Except as provided in Section 4.0, the provisions of this rule apply to any internal combustion engine, rated greater than 50 bhp, that requires a PTO.

The proposed emergency engines are also subject to District Rule 4702, Internal Combustion Engines. Since emissions limits of District Rule 4702 and all other requirements are equivalent or more stringent than District Rule 4701 requirements for emergency engines, compliance with District Rule 4702 requirements will satisfy requirements of District Rule 4701.

District Rule 4702 Internal Combustion Engines

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

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

Both the proposed emergency standby engine powering a generator (N-9742-28-0) and the emergency engine powering a fire pump (N-9742-27-0) are potentially subject to the requirements of District Rule 4702.

. Emergency standby engines are defined in Section 3.0 of District Rule 4702 as follows:

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

The following conditions will be included on the permit for the emergency standby engine powering a generator to ensure the engine meets the definition in Rule 4702:

- *{3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702 and 17 CCR 93115]*

- *{3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702 and 17 CCR 93115]*

Operation of emergency standby engines are limited to 100 hours or less per calendar year for non-emergency purposes. The Air Toxic Control Measure for Stationary Compression Ignition Engines (Stationary ATCM) limits this engine's maintenance and testing to 50 hours/year; therefore, compliance is expected. The following conditions will be included on the permit for the emergency standby engine (N-9742-28-0):

- *{4920} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rules 2201, 4102, and 4702, and 17 CCR 93115]*

The following exemption in Section 4.2 of District Rule 4702 applies to emergency standby engines:

4.2 Except for the requirements of Section 5.9 and Section 6.2.3, the requirements of this rule shall not apply to:
4.2.1 An emergency standby engine as defined in Section 3.0 of this rule, and provided that it is operated with a nonresettable elapsed operating time meter. In lieu of a nonresettable time meter, the owner of an emergency engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Pursuant to the exemption in Section 4.2, the following requirements of Section 5.9 are applicable to emergency standby engines
Section 5.9 requires the owner to:

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

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

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

Properly operate and maintain each engine as recommended by the engine manufacturer or emission control system supplier. The following condition will be included on the permit for the emergency standby engine (N-9742-28-0):

- *{4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]*

Monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier. The following condition will be included on the permit for the emergency standby engine (N-9742-28-0):

- *{3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]*

Install and operate a nonresettable elapsed time meter. In lieu of installing a nonresettable elapsed 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 and EPA and is allowed by Permit-to-Operate condition. The operator shall properly maintain and operate the nonresettable elapsed time meter or alternative device in accordance with the manufacturer's instructions. The following condition will be included on the permit for the emergency standby engine (N-9742-28-0):

- *{4749} This engine shall be equipped with a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District determines that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history. [District Rule 4702 and 17 CCR 93115]*

The exemption in Rule 4702 Section 4.2 for emergency standby engines requires the engines to comply with Section 6.2.3, shown below.

> *6.2.3 An owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and 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.*

Records of the total hours of operation, type of fuel used, purpose for operating the engine, all hours of non-emergency and emergency operation, and other support documentation must be maintained. All records 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 following conditions will be included on the permit for the emergency standby engine (N-9742-28-0):

- *{3496} 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, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]*

- *{4263} The permittee shall maintain monthly records of the type of fuel purchased. [District Rule 4702 and 17 CCR 93115]*

- *{3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]*

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and
3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the emergency IC engine powering a fire pump involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO. Therefore, the following conditions will be included on the permit for the engine powering a fire pump (N-9742-27-0):

- *{3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 100 hours per calendar year. [District Rule 4702 and 17 CCR 93115]*

- *{3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]*

- *{3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]*

- *{3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]*

- *{3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]*

Rule 4801 Sulfur Compounds

Rule 4801 requires that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume.

N-9742-20-0: HydroFlex Fuel Production Unit

For the proposed gaseous fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2000\ \text{ppmvd})\left(8{,}578\frac{\text{dscf}}{\text{MMBtu}}\right)\left(64\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)}{\left(379.5\frac{\text{dscf}}{\text{lb}-\text{mol}}\right)\left(10^6\right)} \cong 2.9\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SO_x emissions from the proposed process heaters are based upon a fuel sulfur content of 1.0 gr-S/100 scf, equivalent to 0.00285 lb/MMBtu. Since this is less than 2.9 lb/MMBtu, it is expected that the process heaters will operate in compliance with this Rule.

N-9742-21-0: Hydrogen Production Unit

For the proposed gaseous fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2000\ \text{ppmvd})\left(8{,}578\frac{\text{dscf}}{\text{MMBtu}}\right)\left(64\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)}{\left(379.5\frac{\text{dscf}}{\text{lb}-\text{mol}}\right)\left(10^6\right)} \cong 2.9\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SO_x emissions from the proposed process heater is based upon a fuel sulfur content of 1.75 gr-S/100 scf, equivalent to 0.0127 lb/MMBtu using the heating content of the process heater fuel. Since this is less than 2.9 lb/MMBtu, it is expected that the process heater will operate in compliance with this Rule.

SOx emissions from RTO #1 are based upon a maximum process gas sulfur content of 1.75 gr/100 scf, equivalent to 0.021 lb/MMBtu using the heating content of the gas entering the RTO.

Since this is less than 2.9 lb/MMBtu, it is expected that RTO #1 will operate in compliance with this Rule.

N-9742-22-0; Boiler

For the proposed gaseous fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2000\ \text{ppmvd})\left(8{,}578\,\frac{\text{dscf}}{\text{MMBtu}}\right)\left(64\,\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)}{\left(379.5\,\frac{\text{dscf}}{\text{lb}-\text{mol}}\right)\left(10^6\right)} \cong 2.9\,\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SO_x emissions from the boiler is based upon a fuel sulfur content of 1.0 gr-S/100 scf, equivalent to 0.00285 lb/MMBtu. Since this is less than 2.9 lb/MMBtu, it is expected that the boiler will operate in compliance with this Rule.

N-9742-23-0: Material Transfer Operation

For the proposed gaseous fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2000\ \text{ppmvd})\left(8{,}578\,\frac{\text{dscf}}{\text{MMBtu}}\right)\left(64\,\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)}{\left(379.5\,\frac{\text{dscf}}{\text{lb}-\text{mol}}\right)\left(10^6\right)} \cong 2.9\,\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SOx emissions from RTO #2 are based upon a maximum process gas sulfur content of 1.75 gr/100 scf, equivalent to 0.021 lb/MMBtu. Since this is less than 2.9 lb/MMBtu, it is expected that RTO #1 will operate in compliance with this Rule.

N-9742-24-0: Wastewater Treatment Unit

For the proposed gaseous fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2000\ \text{ppmvd})\left(8{,}578\,\frac{\text{dscf}}{\text{MMBtu}}\right)\left(64\,\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)}{\left(379.5\,\frac{\text{dscf}}{\text{lb}-\text{mol}}\right)\left(10^6\right)} \cong 2.9\,\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SOx emissions from RTO #1 are based upon a maximum process gas sulfur content of 1.75 gr/100 scf, equivalent to 0.021 lb/MMBtu. Since this is less than 2.9 lb/MMBtu, it is expected that RTO #1 will operate in compliance with this Rule.

N-9742-25-0: Cooling Tower

Sulfur compound emissions are not expected from this emission unit; therefore, compliance with District Rule 4801 requirements is expected.

N-9742-26-0: Emergency Flare

For the proposed gaseous fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2000\ \text{ppmvd})\left(8{,}578\,\frac{\text{dscf}}{\text{MMBtu}}\right)\left(64\,\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)}{\left(379.5\,\frac{\text{dscf}}{\text{lb}-\text{mol}}\right)\left(10^6\right)} \cong 2.9\,\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SOx emissions from the flare are based upon a maximum process gas sulfur content of 22.17 gr/100 scf, equivalent to 0.03 lb/MMBtu. Since this is less than 2.9 lb/MMBtu, it is expected that the flare will operate in compliance with this Rule.

N-9742-27-0: Emergency Firewater Pump

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

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$\frac{0.000015\ \textbf{\textit{lb}}-\textbf{\textit{S}}}{\textbf{\textit{lb}}-\textbf{\textit{fuel}}}\times\frac{7.1\ \text{lb}}{\text{gal}}\times\frac{64\ \text{lb}-\text{SO}_2}{32\ \text{lb}-\text{S}}\times\frac{1\ \text{MMBtu}}{9{,}051\ \text{scf}}\times\frac{1\ \text{gal}}{0.137\ \text{MMBtu}}\times\frac{\text{lb}-\text{mol}}{64\ \text{lb}-\text{SO}_2}\times\frac{10.73\ \text{psi}-\text{ft}^3}{\text{lb}-\text{mol}-{}^\circ\text{R}}\times\frac{520\,{}^\circ\text{R}}{14.7\ \text{psi}}\times 1{,}000{,}000 = 1.0\ \text{ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801.

N-9742-28-0: Emergency Electrical Generator

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

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$\frac{0.000015\ \boldsymbol{lb-S}}{\boldsymbol{lb-fuel}} \times \frac{7.1\ \text{lb}}{\text{gal}} \times \frac{64\ \text{lb}-\text{SO}_2}{32\ \text{lb}-\text{S}} \times \frac{1\ \text{MMBtu}}{9{,}051\ \text{scf}} \times \frac{1\ \text{gal}}{0.137\ \text{MMBtu}} \times \frac{\text{lb}-\text{mol}}{64\ \text{lb}-\text{SO}_2} \times \frac{10.73\ \text{psi}-\text{ft}^3}{\text{lb}-\text{mol}-{}^\circ\text{R}} \times \frac{520^\circ\text{R}}{14.7\ \text{psi}} \times 1{,}000{,}000 = 1.0\ \text{ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801.

N-9742-29-0: Naphtha Storage Tank #1

Sulfur compound emissions are not expected from this emission unit; therefore, compliance with District Rule 4801 requirements is expected.

N-9742-30-0: Naphtha Storage Tank #2

Sulfur compound emissions are not expected from this emission unit; therefore, compliance with District Rule 4801 requirements is expected.

N-9742-31-0: Slop Storage Tank #1

Sulfur compound emissions are not expected from this emission unit; therefore, compliance with District Rule 4801 requirements is expected.

N-9742-32-0: Slop Storage Tank #2

Sulfur compound emissions are not expected from this emission unit; therefore, compliance with District Rule 4801 requirements is expected.

Rule 7012 Hexavalent Chromium – Cooling Towers

This rule is applicable to cooling towers that use chromium containing compounds for treating cooling tower water. The proposed cooling tower does not use chromium containing compounds for treatment. The following condition will be included on the permit for the cooling tower:

- *No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]*

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.

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

The engine powering the fire pump is subject to the requirements of this regulation. The following analysis is applicable to that engine (N-9742-27-0).

Emergency Operating Requirements:

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

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

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.
Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the fire pump engine permit (N-9742-27-0):

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

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a PM_{10} emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation;

c. Hours of operation for emission testing;
d. Initial start-up hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

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

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions will be listed on the fire pump engine permit (N-9742-27-0):

- *{3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]*

- *{3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]*

<u>PM Emissions and Hours of Operation Requirements for New Diesel Engines:</u>

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

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the fire pump engine permit (N-9742-27-0):

- {*edited 3486} Emissions from this IC engine shall not exceed 0.087 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]*

- *{3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 100 hours per calendar year. [District Rule 4702 and 17 CCR 93115]*

The engine powering a generator is also subject to the requirements of this regulation. The following analysis is applicable to the engine powering a generator (N-9742-28-0).

Title 17 CCR Section 93115 Requirements for New Emergency IC Engines Powering Electrical Generators	Proposed Method of Compliance with Title 17 CCR Section 93115 Requirements
Emergency engine(s) must be fired on CARB diesel fuel, or an approved alternative diesel fuel.	The applicant has proposed the use of CARB certified diesel fuel. The proposed permit condition, requiring the use of CARB certified diesel fuel, is included on the permit. • {4258} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801, and 17 CCR 93115]
The engine(s) must meet the emission standards in Table 1 of the ATCM for the specific power rating and model year of the proposed engine.	The applicant has proposed the use of an engine that is certified to the latest EPA Tier Certification standards for the applicable horsepower range, guaranteeing compliance with the emission standards of the ATCM. Additionally, the proposed diesel PM emissions rate is less than or equal to 0.15 g/bhp-hr.

The engine may not be operated more than 50 hours per year for maintenance and testing purposes unless the PM emissions are ≤ 0.01 g/bhp-hr, then the engine is allowed 100 hours per year. Emissions from this engine are certified at 0.022 g/bhp-hr, therefore the engine is allowed 50 hours.	The following conditions will be included on the permit: • {4772} Emissions from this IC engine shall not exceed 0.022 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102, and 17 CCR 93115] • {4920} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rules 2201, 4102, and 4702, and 17 CCR 93115]
Engines, with a PM10 emissions rate greater than 0.01 g/bhp-hr and located at schools, may not be operated for maintenance and testing whenever there is a school sponsored activity on the grounds. Additionally, engines located within 500 feet of school grounds may not be operated for maintenance and testing between 7:30 AM and 3:30 PM	The District has verified that this engine is not located within 500' of a school.
A non-resettable hour meter with a minimum display capability of 9,999 hours shall be installed upon engine installation, or by no later than January 1, 2005, on all engines subject to all or part of the requirements of sections 93115.6, 93115.7, or 93115.8(a) unless the District determines on a case-by-case basis that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history.	The following condition will be included on the permit: • {4749} This engine shall be equipped with a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District determines that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history. [District Rule 4702 and 17 CCR 93115]
An owner or operator shall maintain monthly records of the following: emergency use hours of operation; maintenance and testing hours of operation; hours of operation for	The following condition will be included on the permit: • {3496} 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

emission testing; initial start-up testing hours; hours of operation for all other uses; and the type of fuel used. All records shall be retained for a minimum of 36 months.	operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

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.

<u>District is a Responsible Agency</u>

It is determined that another agency has prepared an environmental review document for the project. The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). As a Responsible Agency, the District is limited to mitigating or avoiding impacts for which it has statutory authority. The District does not have statutory authority for regulating greenhouse gas emissions. The District has determined that the applicant is responsible for implementing greenhouse gas mitigation measures, if any, imposed by the Lead Agency.

District CEQA Findings

The City of Riverbank (City) is the public agency having principal responsibility for approving the 2014 Riverbank Army Ammunition Plant Specific Plan Project. As such, the City served as the Lead Agency for the project. The City approved the project and adopted a Statement of Overriding Consideration (SOC). Subsequently, the City determined the Project to be part of the Riverbank Army Ammunition Plant Specific Plan and prepared an addendum to the EIR in August of 2023. Additionally, the City approved the project in September 2023.

Pursuant to CEQA Guidelines §15250, the District is a Responsible Agency for the ATC project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). As a Responsible Agency, the District complies with CEQA by considering the EIR and Addendum prepared by the Lead Agency, and reaching its own conclusion on whether and how to approve the project involved (CEQA Guidelines §15096). The District has considered the EIR and Addendum certified by the City and prepared findings pursuant to CEQA. As a single purpose agency, the District lacks the Lead Agency's broader scope of authority over the project and does not believe that it should overrule the decisions made by the Lead Agency. Accordingly, after considering the Lead Agency's EIR, Addendum, the SOC, and the substantial evidence the Lead Agency relied on in adopting the SOC, the District finds that it had no basis on which to disagree with the SOC and evidence relied on therein. The District therefore adopts the Lead Agency's SOC by reference as its own.

Furthermore, the Districts engineering evaluation of the project (this document) demonstrates that the District would impose permit conditions. Thus, the District concludes that through a combination of project design elements and permit conditions, project specific stationary source emissions will be reduced to less than significant levels.

Indemnification Agreement/Letter of Credit Determination

The District is the Responsible Agency for this project. This type of operation is of public concern. Therefore, an indemnification agreement is required for this project.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue Authorities to Construct N-9742-20-0 through '-32-0 subject to the permit conditions on the attached draft ATCs in Appendix A.

X. Billing Information

Annual Permit Fees			
Permit Number	**Fee Schedule**	**Fee Description**	**Annual Fee**
N-9742-20-0	3020-02-H	88.6 MMBtu/hr	$1,238
N-9742-21-0	3020-02-H	187.8 MMBtu/hr	$1,238
N-9742-22-0	3020-02-H	59 MMBtu/hr	$1,238
N-9742-23-0	3020-02-G	7.6 MMBtu/hr	$980
N-9742-24-0	3020-02-F	3.8 MMBtu/hr (7.6 MMBtu/hr ÷ 2)	$731
N-9742-25-0	3020-01-E	200 to < 400 HP	$495
N-9742-26-0	3020-02-H	79.17 MMBtu/hr	$1,238
N-9742-27-0	3020-02-D	687 BHP IC Engine	$577
N-9742-28-0	3020-02-F	1,341 BHP IC Engine	$900
N-9742-29-0	3020-05-E	203,700 gallons	$296
N-9742-30-0	3020-05-E	203,700 gallons	$296
N-9742-31-0	3020-05-E	153,000 gallons	$296
N-9742-32-0	3020-05-E	153,000 gallons	$296

Appendixes

A: Draft Authorities to Construct
B: Process Diagram
C: Engine Data Sheet
D: BreezeTanks ESP Results
E.1: BACT Guideline 1.8.5 and Top-Down Analysis for 19.5 MMBtu/hr Process Heater
E.2: BACT Analysis for Process Heaters rated > 20 MMBtu/hr (non-hydrogen production unit)
E.3 BACT Analysis for Hydrogen Production Unit
E.4: BACT Analysis for Chemical Plant Valves and Connectors
E.5: BACT Analysis for Chemical Plants Pumps and Compressor Seals
E.6: BACT Analysis for Hydrogen Production Unit Vents and Wastewater Treatment Plant Vents
E.7: BACT Guideline 1.1.2 and Top-Down BACT Analysis for 59 MMBtu/hr Boiler
E.8: BACT Guideline 7.1.10 and Top-Down BACT Analysis for Material Transfer Operation
E.9: BACT Guideline 3.1.4 and Top-Down BACT Analysis for Emergency Fire Pump Engine
E.10: BACT Guideline 3.1.1 and Top-Down BACT Analysis for Emergency Generator Engine
E.11: BACT Guideline 7.3.3 and Top-Down BACT Analysis for Organic Liquid Storage Tanks
F: HAP Emissions
G: Copy of US EPA Protocol for Equipment Leak Emissions Table 2-10 formulas
H: Risk Management Review and Ambient Air Quality Analysis Results
I: Quarterly Net Emission Change

APPENDIX A
Draft Authorities to Construct

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-20-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
HYDROFLEX FUEL PRODUCTION UNIT CONSISTING OF A HYDROGENATION REACTOR, DEWAXING REACTOR, GAS AND LIQUID SEPARATION EQUIPMENT, FIXED-BED CATALYST VESSELS, SOUR GAS TREATMENT EQUIPMENT, A 19.5 MMBTU/HR NATURAL GAS-FIRED PROCESS HEATER WITH AN OXIDATION CATALYST, ULTRA LOW-NOX BURNER AND SELECTIVE CATALYTIC REDUCTION, A 27.6 MMBTU/HR NATURAL GAS FIRED PROCESS HEATER WITH AN OXIDATION CATALYST, ULTRA LOW-NOX BURNER AND SELECTIVE CATALYTIC REDUCTION, AND A 41.5 MMBTU/HR NATURAL GAS-FIRED PROCESS HEATER WITH AN OXIDATION CATALYST, ULTRA LOW-NOX BURNER AND SELECTIVE CATALYTIC REDUCTION SYSTEM; OR EQUIVALENT

CONDITIONS

1. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
2. {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]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. Each of the three process heaters shall only be fired on PUC quality natural gas. [District Rules 2201, 4305, 4306, and 4320]
5. For each process heater, the exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
6. For each of the three process heaters, the emission control system shall be in operation and emissions shall be minimized insofar as technologically possible during startup and shutdown of the unit. [District Rules 2201, 4305, 4306, and 4320]

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
N-9742-20-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

7. The total combined duration of startup and shutdowns for the 19.5 MMBtu/hr process heater shall not exceed 8 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 8 hours and the duration of each individual shutdown event shall not exceed 2 hours.The total combined duration of startup and shutdowns for the 19.5 MMBtu/hr process heater shall not exceed 8 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. [District Rules 2201, 4305, 4306, and 4320]

8. Except during startup and shutdown, emissions from the 19.5 MMBtu/hr process heater shall not exceed 5 ppmvd NOx @ 3% O2 or 0.0061 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

9. During startup and shutdown, emissions from the 19.5 MMBtu/hr process heater shall not exceed 50 ppmvd NOx @ 3% O2 or 0.061 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

10. Emissions from the 19.5 MMBtu/hr process heater shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.00285 lb-SOx/MMBtu, 0.00055 lb-VOC/MMBtu, 0.003 lb-PM10/MMBtu, and 5 ppmvd NH3 @ 3% O2 or 0.0022 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

11. The total combined duration of startup and shutdowns for the 27.6 MMBtu/hr process heater shall not exceed 8 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 8 hours and the duration of each individual shutdown event shall not exceed 2 hours. [District Rules 2201, 4305, 4306, and 4320]

12. Except during startup and shutdown, emissions from the 27.6 MMBtu/hr process heater shall not exceed 2.5 ppmvd NOx @ 3% O2 or 0.003 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

13. During startup and shutdown, emissions from the 27.6 MMBtu/hr process heater shall not exceed 50 ppmvd NOx @ 3% O2 or 0.061 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

14. Emissions from the 27.6 MMBtu/hr process heater shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.00285 lb-SOx/MMBtu, 0.00055 lb-VOC/MMBtu, 0.003 lb-PM10/MMBtu, and 5 ppmvd NH3 @ 3% O2 or 0.0022 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

15. The total combined duration of startup and shutdowns for the 41.5 MMBtu/hr process heater shall not exceed 8 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 8 hours and the duration of each individual shutdown event shall not exceed 2 hours. [District Rules 2201, 4305, 4306, and 4320]

16. Except during startup and shutdown, emissions from the 41.5 MMBtu/hr process heater shall not exceed 2.5 ppmvd NOx @ 3% O2 or 0.003 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

17. During startup and shutdown, emissions from the 41.5 MMBtu/hr process heater shall not exceed 50 ppmvd NOx @ 3% O2 or 0.061 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

18. Emissions from the 41.5 MMBtu/hr process heater shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.00285 lb-SOx/MMBtu, 0.00055 lb-VOC/MMBtu, 0.003 lb-PM10/MMBtu, and 5 ppmvd NH3 @ 3% O2 or 0.0022 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

19. Total fugitive VOC emissions from the hydroflex unit shall not exceed 19.1 lb/day and 6,918 lb/rolling 12-month period. [District Rule 2201]

20. Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]

21. Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rule 2201]

22. Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]

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CONDITIONS CONTINUE ON NEXT PAGE

23. For each process heater, source testing to measure NOx, CO, VOC, and NH3 emissions during steady state operation shall be conducted within 60 days of startup and at least once every twelve (12) months thereafter. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 2201, 4305, 4306, and 4320]

24. The following test methods shall be used: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (lb/MMBtu) - EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4; SOx - EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content - EPA Method 11 or 15; ammonia - BAAQMD ST1B and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rules 2201, 4305, 4306, and 4320]

25. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 4305, 4306, and 4320]

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

27. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]

28. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

29. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

30. For each process heater, the permittee shall monitor and record the stack concentration of NOx, CO, NH3 and O2 at least once during each month in which source testing is not performed. NOx, CO and O2 monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH3 monitoring shall be conducted utilizing gas detection tubes (Draeger brand or District approved equivalent). Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless it has been performed within the last month. [District Rules 4305, 4306, and 4320]

31. If either the NOx, CO or NH3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

32. All NOx, CO, O2 and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NOx, CO and O2 analyzer as well as the NH3 emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

33. Ammonia emissions readings shall be conducted at the time the NOx, CO and O2 readings are taken. The readings shall be converted to ppmvd @ 3% O2. [District Rules 4305, 4306, and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

34. For each process heater, permittee shall determine sulfur content of combusted gas annually or shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320]

35. The permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx, CO and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 4305, 4306, and 4320]

36. The operator shall not use any component that leaks in excess of the leak limits of this permit, except as follows. A component identified as leaking in excess of the leak limits of this permit may be used provided it has been identified with a tag for repair, has been repaired, or is awaiting re-inspection after repair, within the applicable time period specified within Rule 4455. [District Rules 2201 and 4405]

37. Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere. [District Rule 4455]

38. The owner or operator shall audio-visually inspect (by hearing and sight) all accessible operating pumps, compressors and pressure relief devices for leaks at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. [District Rule 4455]

39. Any audio-visual inspection of all accessible operating pumps, compressors, and pressure relief devices in service that indicates a leak that cannot be immediately repaired to meet the leak requirements of this permit shall be inspected to determine the gaseous leak concentration using an instrument in accordance with EPA Method 21 not later than 24 hours after conducting the audio-visual inspection. If the gas leak concentration is greater than 50,000 ppmv (as methane), the leak must be repaired within 2 calendar days. If the gas leak concentration is greater than the gas leak concentration is greater than 10,000 ppmv but equal to or less than 50,000 ppmv (as methane), the leak must be repaired 3 calendar days. If the leak is greater than the leak concentrations allowed in this permit but less than or equal to 10,000 ppmv (as methane), then the leak must be repaired within 7 calendar days. [District Rule 4455]

40. The operator shall inspect all components at least once every calendar quarter using an instrument in accordance with EPA Method 21, except for inaccessible components and unsafe-to-monitor components, or pipes. [District Rule 4455]

41. The operator shall inspect, immediately after placing into service, all new, replaced, or repaired fittings, flanges, and threaded connections using an instrument in accordance with EPA Method 21. [District Rule 4455]

42. The operator shall inspect all inaccessible components at least once every 12 months using an instrument in accordance with EPA Method 21. [District Rule 4455]

43. The operator shall inspect all unsafe-to-monitor components during each turnaround using an instrument in accordance with EPA Method 21. [District Rule 4455]

44. The operator shall perform an audio-visual inspection on all pipes for leaks at least every 12 months. Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this permit shall be inspected using an instrument in accordance with EPA Method 21 within 24 hours after conducting the audio-visual inspection. If there is a visible mist or continuous flow of liquid that is not seal lubricant from the pipe, the leak must be fixed within 2 calendar days of detection. If there is a liquid leak, except seal lubricant, that is not a visible mist or continuous flow and drips liquid at a rate of more than three drops per minute, the leak shall be fixed within 3 calendar days of detection. [District Rule 4455]

45. The operator shall initially inspect a process pressure relief device that releases to the atmosphere as soon as practicable but no later than 24 hours after the time of release. The operator shall re-inspect the process pressure relief device using an instrument in accordance with EPA Method 21 no earlier than 24 hours after the initial inspection but no later than 15 calendar days after the date of the release to insure that the process pressure relief device is operating properly and is leak free. If the pressure relief device is found to be leaking at either inspection, the pressure relief device leak shall be treated as if the leak was found during quarterly inspections. [District Rule 4455]

46. Except for process pressure relief devices, a component shall be inspected using an instrument in accordance with EPA Method 21 within 15 calendar days after repairing the leak or replacing the component. [District Rule 4455]

CONDITIONS CONTINUE ON NEXT PAGE

55. All major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator and District personnel to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but no later than 24 hours after discovery. [District Rule 4455]

56. The operator shall submit an Operator Management Plan for approval to the APCO. The operator shall describe in the Operator Management Plan all components Subject to Rule 4455 or exempt pursuant to Subject 4.0. The plan shall contain a descriptions and procedures that the operator will use to comply with the requirements of Rule 4455. The Plan shall include, at a minimum, all of the following information: 1) Identification and description of any known hazard that might affect the safety of an inspector; 2) Diagrams, charts, spreadsheets, or other methods approved by the APCO which describe the following: 2a) Except for pipes, the number of components that are subject to Rule 4455 by component type and type of service (liquid or gas); 2b) Except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components that are subject to Rule 4455 including the reasons for such designation; 2c) Except for pipes, the location of components that are subject to this rule (components may be grouped together functionally by process unit or facility description; 2d) Except for pipes components exempt pursuant to Section 4.2 (except for components buried below ground) may be described by grouping them functionally by process unit or facility description. The results of any laboratory testing or other pertinent information to demonstrate compliance with the exemption criteria for components shall be submitted with the Operator Management Plan; 3) Detailed schedule of inspection to be conducted as required by Rule 4455; 4) Include the compliance plan for process pressure relief devices as required by Rule 4455; 5) Specify whether a qualified contractor or in-house team will perform inspections; 6) Establish an employee training program for inspecting, repairing, and recordkeeping procedures; 6a) Specify the training standards for personnel performing inspections and repairs; 6b) document the leak detection training using instruments in accordance with EPA Method 21. The operator shall maintain records of the Operator management plan and training records at the facility. Copies of such records shall be made available to the APCO, ARB, and US EPA upon request. [District Rule 4455]

57. By January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any changes to the existing Operator Management Plan. [District Rule 4455]

58. The District shall provide written notice of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such Plan. If the District fails to respond in writing within 60 days after the date of receiving the Plan, it shall be deemed approved. No provision of the Plan, approved or not, shall conflict with or take precedence over any provision of Rule 4455. [District Rule 4455]

59. The operator shall maintain an inspection log containing the following: 1) Total number of components inspected, and total number and percentage of leaking components found by component type; 2) Location, type, name or description of each leaking component, and description of any unit where the leaking component is found; 3) Date of leak detection and method of leak detection; 4) For gaseous leaks, the concentration in ppmv, and for liquid leaks, whether the liquid leak is a major leak (a visible mist or continuous flow of liquid that is not seal lubricant) or a minor leak (a liquid leak, except seal lubricant, that is not a major liquid leak and drips liquid at a rate of more than three drops per minute); 5) Date of repair, replacement, or removal from operation of leaking components; 6) Identification and location of essential component and critical components found leaking that cannot be repaired until the next process turnaround or not later than one year after leak detection, whichever comes earlier; 7) Methods used to minimize the leak from essential components and critical components that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes later; 8) After the component is repaired or replaced, the date of re-inspection and the leak concentration in ppmv; 9) Inspectors name, business mailing address, and business telephone number; and 10) The facility operator responsible for inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log. [District Rule 4455]

60. Records of leaks detected by quarterly or annual operator inspection and each subsequent repair and re-inspection shall be submitted to the APCO, ARB, or USA upon request. [District Rule 4455]

61. Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of the current calibration gas certification from the vendor of said calibration gas, analyzer reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, caliber gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4455]

CONDITIONS CONTINUE ON NEXT PAGE

62. The operator shall notify the District, by telephone or other methods approved by the District, of any process pressure relief device release. [District Rule 4455]

63. The operator shall submit a written report to the District within 30 calendar days following the notification of a process pressure release device release. The report shall include the following: 1) Process pressure release device type, size and location; 2) Date, time, and duration of process pressure relief device release; 3) Types of VOC release and individual amounts, in pounds, including supporting calculations; 4) Cause of the pressure release device release; and 5) Corrective actions taken to prevent a subsequent pressure release device release. [District Rule 4455]

64. The operator shall keep records of the process parameters monitored for pressure release devices. [District Rule 4455]

65. Measurements of gaseous leak concentrations using EPA Method 21 shall be made using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with US EPA Method 21 or the manufacturer's instructions, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. [District Rule 4455]

66. After June 30, 2024, all leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two calendar days of initial OGI leak detection, or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component do determine compliance with the leak thresholds and repair timeframes specified in Table 5 of Rule 4455. [District Rule 4455]

67. For each process heater, the owner or operator shall maintain records of the date, duration of each startup and shutdown event (hour/event), total duration of startup and shutdown time (hours/day), and total duration of startup and shutdown time per year (hours/year). The annual records shall be updated at least on a monthly basis. [District Rules 2201, 4305, 4306, and 4320]

68. The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]

69. All records shall be retained for a minimum of five years and shall be made available to the District, ARB, or US EPA upon request. [District Rules 1070, 2201, 4305, 4306, 4320, and 4455]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-21-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
HYDROGEN PRODUCTION UNIT CONSISTING OF A HYDROTREATER, PRE-REFORMER, REFORMER, SHIFT CONVERTERS, AND PRESSURE SWING ADSORBER WITH A 184 MMBTU/HR PROCESS GAS AND NATURAL GAS-FIRED HEATER WITH A CO CATALYST, LOW-NOX BURNER, AND SELECTIVE CATALYTIC REDUCTION SYSTEM; OR EQUIVALENT. HYDROGEN PRODUCTION UNIT GAS IS VENTED TO A SHARED THERMAL OXIDIZER (RTO #1 SHARED WITH N-9742-24-0) WITH A 7.6 MMBTU/HR NATURAL GAS-FIRED BURNER

CONDITIONS

1. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
2. {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]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. For the process heater and the regenerative thermal oxidizer, 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]
5. For the process heater, the emission control system shall be in operation and emissions shall be minimized insofar as technologically possible during startup and shutdown of the unit. [District Rules 2201, 4305, 4306, and 4320]
6. The process heater shall only be fired on PUC quality natural gas and process gas. [District Rules 2201, 4305, 4306, and 4320]
7. The sulfur content of the process gas supplied to the process heater shall not exceed 1.75 grains/100 dscf. [District Rule 2201]

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

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Brian Clements, Director of Permit Services
N-9742-21-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

8. The total combined duration of startup and shutdowns for the process heater shall not exceed 12 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 12 hours and the duration of each individual shutdown event shall not exceed 2 hours. [District Rules 2201, 4305, 4306, and 4320]
9. Except during startup and shutdown, emissions from the process heater shall not exceed 2.5 ppmvd NOx @ 3% O2 or 0.003 lb-NOx/MMBtu. [[District Rule 2201]
10. During startup and shutdown, emissions from the process heater shall not exceed 0.14 lb-NOx/MMBtu. [District Rule 2201]
11. Emissions from the process heater shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.0127 lb-SOx/MMBtu, 0.000275 lb-VOC/MMBtu, 0.0038 lb-PM10/MMBtu, and 5 ppmvd NH3 @ 3% O2 or 0.002 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306, and 4320]
12. The regenerative thermal oxidizer shall only be fired on PUC-Quality natural gas as a supplemental fuel. [District Rule 2201]
13. The VOC control efficiency of the regenerative thermal oxidizer shall be at least 99% by weight. [District Rule 2201]
14. Natural gas combustion emissions from the regenerative thermal oxidizer serving the material transfer operations shall not exceed any of the following: 5 ppmvd NOx @ 3% O2 or 0.0062 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0038 lb-CO/MMBtu, and 0.0055 lb-VOC/MMBtu. [District Rule 2201]
15. The heat input from the process gas into the regenerative thermal oxidizer shall not exceed 270 MMBtu/day and shall not exceed 270 MMBtu/rolling 12-month period. [District Rule 2201]
16. Process gas combustion emissions from the regenerative thermal oxidizer serving the hydrogen production unit and the wastewater treatment plant (N-9742-24) shall not exceed any of the following: 5 ppmv NOx @ 3% O2 or 0.0061 lb-NOx/MMBtu, 0.0106 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0035 lb-CO/MMBtu, and 0.0106 lb-VOC/MMBtu. [District Rule 2201]
17. The sulfur content of process gas routed to the regenerative thermal oxidizer shall not exceed 1.75 grains/100 scf. [District Rule 2201]
18. Total fugitive VOC emissions from the hydrogen production unit shall not exceed 8.2 lb/day and 3,031 lb/rolling 12-month period. [District Rule 2201]
19. Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]
20. Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rule 2201]
21. Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]
22. For the process heater, source testing to measure NOx, CO, VOC, and NH3 emissions during steady state operation shall be conducted within 60 days of startup and at least once every twelve (12) months thereafter. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 2201, 4305, 4306, and 4320]
23. The following test methods shall be used for process heater testing: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (lb/MMBtu) - EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4; SOx - EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content - EPA Method 11 or 15; ammonia - BAAQMD ST1B and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rules 2201, 4305, 4306, and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

24. Fuel H_2S, total sulfur, and methane content for the process gas routed to the process heater shall be determined annually using the following test methods H_2S: ASTM D6228; total sulfur: ASTM D1072; ASTM D3246, or ASTM D6228; and methane content: ASTM D1945. The operator shall keep records of the process gas testing results. [District Rules 2201, 4305, 4306, and 4320]

25. Source testing to measure NOx, VOC (at thermal oxidizer inlet), VOC (at thermal oxidizer outlet), and VOC control efficiency of the thermal oxidizer shall be conducted within 60 days of startup and annually thereafter. [District Rule 2201]

26. The following test methods shall be used for testing of the regenerative thermal oxidizer: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; VOC (ppmv or lb/MMBtu) - EPA Method 18 or EPA Method 25; Stack gas oxygen (O_2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4 and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201]

27. Fuel H_2S, total sulfur, and methane content for the process gas routed to the regenerative thermal oxidizer shall be determined annually using the following test methods H_2S: ASTM D6228; total sulfur: ASTM D1072; ASTM D3246, or ASTM D6228; and methane content: ASTM D1945. The operator shall keep records of the process gas testing results. [District Rule 2201]

28. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 2201, 4305, 4306, and 4320]

29. For the process heater, the source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

30. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 2201, 4305, 4306 and 4320]

31. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

32. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

33. For the process heater, the permittee shall monitor and record the stack concentration of NOx, CO, NH_3 and O_2 at least once during each month in which source testing is not performed. NOx, CO and O_2 monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH_3 monitoring shall be conducted utilizing gas detection tubes (Draeger brand or District approved equivalent). Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless it has been performed within the last month. [District Rules 4305, 4306, and 4320]

34. If either the NOx, CO or NH_3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

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CONDITIONS CONTINUE ON NEXT PAGE

35. All NOx, CO, O2 and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NOx, CO and O2 analyzer as well as the NH3 emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

36. Ammonia emissions readings shall be conducted at the time the NOx, CO and O2 readings are taken. The readings shall be converted to ppmvd @ 3% O2. [District Rules 4305, 4306, and 4320]

37. The permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx, CO and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 4305, 4306, and 4320]

38. The regenerative thermal oxidizer shall be operated with a combustion chamber temperature of no less than 1400 degrees F and the retention time shall be no less than 0.5 seconds. A continuous temperature monitoring and recording device shall be used and kept in good working order. [District Rule 2201]

39. The regenerative thermal oxidizer shall be heated to proper operating temperature prior to any process air entering the oxidizer. [District Rule]

40. The operator shall not use any component that leaks in excess of the leak limits of this permit, except as follows. A component identified as leaking in excess of the leak limits of this permit may be used provided it has been identified with a tag for repair, has been repaired, or is awaiting re-inspection after repair, within the applicable time period specified within Rule 4455. [District Rules 2201 and 4405]

41. Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere. [District Rule 4455]

42. The owner or operator shall audio-visually inspect (by hearing and sight) all accessible operating pumps, compressors and pressure relief devices for leaks at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. [District Rule 4455]

43. Any audio-visual inspection of all accessible operating pumps, compressors, and pressure relief devices in service that indicates a leak that cannot be immediately repaired to meet the leak requirements of this permit shall be inspected to determine the gaseous leak concentration using an instrument in accordance with EPA Method 21 not later than 24 hours after conducting the audio-visual inspection. If the gas leak concentration is greater than 50,000 ppmv (as methane), the leak must be repaired within 2 calendar days. If the gas leak concentration is greater than the gas leak concentration is greater than 10,000 ppmv but equal to or less than 50,000 ppmv (as methane), the leak must be repaired 3 calendar days. If the leak is greater than the leak concentrations allowed in this permit but less than or equal to 10,000 ppmv (as methane), then the leak must be repaired within 7 calendar days. [District Rule 4455]

44. The operator shall inspect all components at least once every calendar quarter using an instrument in accordance with EPA Method 21, except for inaccessible components and unsafe-to-monitor components, or pipes. [District Rule 4455]

45. The operator shall inspect, immediately after placing into service, all new, replaced, or repaired fittings, flanges, and threaded connections using an instrument in accordance with EPA Method 21. [District Rule 4455]

46. The operator shall inspect all inaccessible components at least once every 12 months using an instrument in accordance with EPA Method 21. [District Rule 4455]

47. The operator shall inspect all unsafe-to-monitor components during each turnaround using an instrument in accordance with EPA Method 21. [District Rule 4455]

CONDITIONS CONTINUE ON NEXT PAGE

48. The operator shall perform an audio-visual inspection on all pipes for leaks at least every 12 months. Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this permit shall be inspected using an instrument in accordance with EPA Method 21 within 24 hours after conducting the audio-visual inspection. If there is a visible mist or continuous flow of liquid that is not seal lubricant from the pipe, the leak must be fixed within 2 calendar days of detection. If there is a liquid leak, except seal lubricant, that is not a visible mist or continuous flow and drips liquid at a rate of more than three drops per minute, the leak shall be fixed within 3 calendar days of detection. [District Rule 4455]

49. The operator shall initially inspect a process pressure relief device that releases to the atmosphere as soon as practicable but no later than 24 hours after the time of release. The operator shall re-inspect the process pressure relief device using an instrument in accordance with EPA Method 21 no earlier than 24 hours after the initial inspection but no later than 15 calendar days after the date of the release to insure that the process pressure relief device is operating properly and is leak free. If the pressure relief device is found to be leaking at either inspection, the pressure relief device leak shall be treated as if the leak was found during quarterly inspections. [District Rule 4455]

50. Except for process pressure relief devices, a component shall be inspected using an instrument in accordance with EPA Method 21 within 15 calendar days after repairing the leak or replacing the component. [District Rule 4455]

51. A District inspection in no way fulfills any of the mandatory inspection requirements placed upon the operator and cannot be used or counted as an inspection required of an operator. Any attempt by an operator to count such District inspections as part of the mandatory operator's inspections is considered a willful circumvention of the Rule 4455 and is a violation of Rule 4455. [District Rule 4455]

52. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag. The tag shall include the following information: 1) Date and time of leak detection; 2) Date and time of leak measurement; 3) for gas leaks, indicate the leak concentration in ppmv; 4) for liquid leaks, indicate whether the leak is a Major leak (a leak with visible mist or a continuous flow that is not seal lubricant) or a minor leak (a liquid leak that is not a Major leak, but is in excess of three drops per minute); and 5) For essential components, unsafe-to monitor components, and critical components, indicate so on the tag. The tag shall remain affixed to the component until all of the following conditions are met: 1) the leaking component has been repaired or replace; 2) The component has been re-inspected using an instrument in accordance with EPA Method 21; and 3) The component is found to be in compliance with the leak requirements of this permit. [District Rule 4455]

53. The operator shall minimize all component leaks immediately to the extent possible, but not later than one hour after detection of the leaks in order to stop or reduce leakage to the atmosphere. If the leak has been minimized but the leak still exceeds the applicable leak standards in this permit, the operator shall comply with at least one of the following as soon as possible: 1) Repair or replace the leaking component; or 2) Vent the leaking component to a closed vent system; or 3) Remove the leaking component from service. The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in Table 3 of Rule 4455. The start of the repair period shall be the time of the initial leak detection. [District Rule 4455]

54. If a leaking component is an essential component or a critical component and which cannot be immediately shutdown for repairs, the operator shall: 1) Minimize the leak within one hour after detection; and 2) If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of this permit, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 4455]

CONDITIONS CONTINUE ON NEXT PAGE

55. For any component that has incurred five repair actions for major gas leaks (> 10,000 ppmv) or major liquid leaks (a visible mist or continuous flow of liquid that is not seal lubricant), or a combination of major gas leaks and major liquid leaks in a continuous 12 month period, the operator shall comply with at least one of the following: 1) Replace or retrofit the component with the control technology specified in Table 4 of Rule 4455 and notify the APCO in writing prior to replacing or retrofitting the component; or 2) Replace the component with Achieved-in-Practice Best Available Control Technology (BACT) equipment, as determined in accordance with District Rule 2201 and as approved by the APCO in writing; or 3) Vent the component to an APCO approved closed vent system or 4) Remove the component from operation. For any component that is accessible, is not unsafe-to-monitor, is not an essential component, and is not a critical component, the operator shall perform one of the above four actions as soon as practicable, but no later than 12 months after the date of detection of the fifth major leak in a continuous 12-month period. For any inaccessible component, unsafe-to-monitor component, essential component, or critical component, the operator shall perform one of the above four actions as soon as practicable but not later than the next turnaround or not later than 2 years after the date of detection of the fifth major component leak within a continuous 12-month period. An entire compressor or pump need not be replaced provided the compressor parts or pump parts that incurred five repair action are brought into compliance. [District Rule 4455]

56. The operator shall monitor process pressure relief devices using electronic process control instrumentation that allows for real time continuous parameter monitoring or by using telltale indicators for the process pressure relief device where parameter monitoring is not feasible. [District Rule 4455]

57. The operator shall submit a compliance plan as part of the Operator Management Plan containing an inventory of process pressure relief devices by size, set pressure and location, and the type of monitoring system used. If applicable, the operator shall indicate the process parameter selected for continuous monitoring and justification for such selection. [District Rule 4455]

58. After the release from process pressure relief device in excess of 500 pounds of VOC in a continuous 24-hour period, the operator shall immediately conduct a failure analysis and implement corrective actions as soon as practicable, but no later than 30 days, to prevent the reoccurrence of such release. [District Rule 4455]

59. All major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator and District personnel to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but no later than 24 hours after discovery. [District Rule 4455]

60. The operator shall submit an Operator Management Plan for approval to the APCO. The operator shall describe in the Operator Management Plan all components Subject to Rule 4455 or exempt pursuant to Subject 4.0. The plan shall contain a descriptions and procedures that the operator will use to comply with the requirements of Rule 4455. The Plan shall include, at a minimum, all of the following information: 1) Identification and description of any known hazard that might affect the safety of an inspector; 2) Diagrams, charts, spreadsheets, or other methods approved by the APCO which describe the following: 2a) Except for pipes, the number of components that are subject to Rule 4455 by component type and type of service (liquid or gas); 2b) Except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components that are subject to Rule 4455 including the reasons for such designation; 2c) Except for pipes, the location of components that are subject to this rule (components may be grouped together functionally by process unit or facility description; 2d) Except for pipes components exempt pursuant to Section 4.2 (except for components buried below ground) may be described by grouping them functionally by process unit or facility description. The results of any laboratory testing or other pertinent information to demonstrate compliance with the exemption criteria for components shall be submitted with the Operator Management Plan; 3) Detailed schedule of inspection to be conducted as required by Rule 4455; 4) Include the compliance plan for process pressure relief devices as required by Rule 4455; 5) Specify whether a qualified contractor or in-house team will perform inspections; 6) Establish an employee training program for inspecting, repairing, and recordkeeping procedures; 6a) Specify the training standards for personnel performing inspections and repairs; 6b) document the leak detection training using instruments in accordance with EPA Method 21. The operator shall maintain records of the Operator management plan and training records at the facility. Copies of such records shall be made available to the APCO, ARB, and US EPA upon request. [District Rule 4455]

61. By January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any changes to the existing Operator Management Plan. [District Rule 4455]

CONDITIONS CONTINUE ON NEXT PAGE

62. The District shall provide written notice of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such Plan. If the District fails to respond in writing within 60 days after the date of receiving the Plan, it shall be deemed approved. No provision of the Plan, approved or not, shall conflict with or take precedence over any provision of Rule 4455. [District Rule 4455]

63. The operator shall maintain an inspection log containing the following: 1) Total number of components inspected, and total number and percentage of leaking components found by component type; 2) Location, type, name or description of each leaking component, and description of any unit where the leaking component is found; 3) Date of leak detection and method of leak detection; 4) For gaseous leaks, the concentration in ppmv, and for liquid leaks, whether the liquid leak is a major leak (a visible mist or continuous flow of liquid that is not seal lubricant) or a minor leak (a liquid leak, except seal lubricant, that is not a major liquid leak and drips liquid at a rate of more than three drops per minute); 5) Date of repair, replacement, or removal from operation of leaking components; 6) Identification and location of essential component and critical components found leaking that cannot be repaired until the next process turnaround or not later than one year after leak detection, whichever comes earlier; 7) Methods used to minimize the leak from essential components and critical components that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes later; 8) After the component is repaired or replaced, the date of re-inspection and the leak concentration in ppmv; 9) Inspectors name, business mailing address, and business telephone number; and 10) The facility operator responsible for inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log. [District Rule 4455]

64. Records of leaks detected by quarterly or annual operator inspection and each subsequent repair and re-inspection shall be submitted to the APCO, ARB, or USA upon request. [District Rule 4455]

65. Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of the current calibration gas certification from the vendor of said calibration gas, analyzer reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, caliber gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4455]

66. The operator shall notify the District, by telephone or other methods approved by the District, of any process pressure relief device release. [District Rule 4455]

67. The operator shall submit a written report to the District within 30 calendar days following the notification of a process pressure release device release. The report shall include the following: 1) Process pressure release device type, size and location; 2) Date, time, and duration of process pressure relief device release; 3) Types of VOC release and individual amounts, in pounds, including supporting calculations; 4) Cause of the pressure release device release; and 5) Corrective actions taken to prevent a subsequent pressure release device release. [District Rule 4455]

68. The operator shall keep records of the process parameters monitored for pressure release devices. [District Rule 4455]

69. Measurements of gaseous leak concentrations using EPA Method 21 shall be made using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with US EPA Method 21 or the manufacturer's instructions, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. [District Rule 4455]

70. After June 30, 2024, all leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two calendar days of initial OGI leak detection, or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component do determine compliance with the leak thresholds and repair timeframes specified in Table 5 of Rule 4455. [District Rule 4455]

71. For the process heater, the owner or operator shall maintain records of the date, duration of each startup and shutdown event (hour/event), total duration of startup and shutdown time (hours/day), and total duration of startup and shutdown time per year (hours/year). The annual records shall be updated at least on a monthly basis. [District Rules 2201, 4305, 4306, and 4320]

72. The permittee shall keep a record of the regenerative thermal oxidizer temperature readings collected from the data recorder on a daily basis. [District Rule 2201]

73. The permittee shall keep a record of the quantity of process gas (in MMBtu) processed each day by the regenerative thermal oxidizer and a record of the cumulative quantity of process gas (in MMBtu) processed in each rolling 12-month period by the regenerative thermal oxidizer. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

74. The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]

75. All records shall be retained for a minimum of five years and shall be made available to the District, ARB, or US EPA upon request. [District Rules 2201, 4305, 4306, 4320,and 4455]

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San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-22-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
59 MMBTU/HR NATURAL GAS-FIRED AUXILIARY BOILER WITH CO CATALYST AND LOW NOX BURNER AND SELECTIVE CATALYTIC REDUCTION (SCR) OR EQUIVALENT

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
3. {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]
4. The boiler shall only be fired on PUC-quality natural gas. [District Rules 2201, 4305, 4306, and 4320]
5. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [40 CFR 60.48c(g)]
6. The emission control system shall be in operation and emissions shall be minimized insofar as technologically possible during startup and shutdown of the unit. [District Rules 2201, 4305, 4306 and 4320]
7. The total combined duration of startup and shutdowns for the boiler shall not exceed 8 hours in any one day and shall not exceed 200 hours in any rolling 12-month period. The duration of each individual startup event shall not exceed 8 hours and the duration of each individual shutdown event shall not exceed 2 hours [District Rules 2201, 4305, 4306, and 4320]
8. Except during startup and shutdown, emissions from the boiler shall not exceed 2.5 ppmvd NOx @ 3% O2 or 0.003 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST 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

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Brian Clements, Director of Permit Services
N-9742-22-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

9. During startup and shutdown, emissions from the boiler shall not exceed 50 ppmvd @ 3% O2 or 0.062 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

10. Emissions from the boiler shall not exceed any of the following limits: 25 ppmvd CO @ 3% O2 or 0.018 lb-CO/MMBtu, 0.00285 lb-SOx/MMBtu, 0.00055 lb-VOC/MMBtu, 0.003 lb-PM10/MMBtu, and 10 ppmvd NH3 @ 3% O2 or 0.0045 lb-NH3/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

11. Source testing to measure natural gas-combustion NOx, CO, VOC and ammonia slip emissions shall be conducted within 60 days of startup and at least once every twelve (12) months thereafter (no more than 30 days before or after the required annual source test date). After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months (no more than 30 days before or after the required 36-month source test date). If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 2201, 4305, 4306, and 4320]

12. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

13. {4352} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]

14. The following test methods shall be used: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (lb/MMBtu) - EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4; SOx - EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content - EPA Method 11 or 15; ammonia - BAAQMD ST1B and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rules 2201, 4305, 4306, and 4320]

15. {4350} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

16. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 2201, 4305, 4306, and 4320]

17. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

18. {4319} The permittee shall monitor and record the stack concentration of NOx, CO, NH3 and O2 at least once during each month in which source testing is not performed. NOx, CO and O2 monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH3 monitoring shall be conducted utilizing Draeger 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 it has been performed within the last month. [District Rules 4305, 4306 and 4320]

19. {4320} If the NOx, CO or NH3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

20. {4321} All NOx, CO, O2 and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NOx, CO and O2 analyzer as well as the NH3 emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320]

21. {4322} Ammonia emission readings shall be conducted at the time the NOx, CO and O2 readings are taken. The readings shall be converted to ppmvd @ 3% O2. [District Rules 4305, 4306 and 4320]

22. The permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx, CO and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 2201, 4305, 4306 and 4320]

23. {4356} Permittee shall determine sulfur content of combusted gas annually or shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320]

24. The owner or operator shall maintain records of the amount of fuel combusted during each calendar month in this unit. [40 CFR 60.48c(g)]

25. The owner or operator shall maintain records of the date, duration of each startup and shutdown event (hour/event), total duration of startup and shutdown time (hours/day), and total duration of startup and shutdown time per year (hours/year). The annual records shall be updated at least on a monthly basis [District Rules 2201, 4305, 4306, and 4320]

26. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, 4305, 4306 and 4320, and 40 CFR 60.48c(i)]

San Joaquin Valley Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-23-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
MATERIAL TRANSFER OPERATION (RECEIVING OF FEEDSTOCKS AND OFFLOADING OF PRODUCTS VIA A LOADING RACK TO AND FROM TRUCKS AND RAILCARS) VENTED TO A THERMAL OXIDIZER (RTO #2) WITH A 7.6 MMBTU/HR NATURAL GAS FIRED BURNER

CONDITIONS

1. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
2. {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]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. For the regenerative thermal oxidizer, 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]
5. Organic liquid loading operations shall be bottom loaded (submerged pipe fill loading). [District Rule 4624]
6. The regenerative thermal oxidizer shall only be fired on PUC-Quality natural gas as a supplemental fuel. [District Rule 2201]
7. The VOC control efficiency of the regenerative thermal oxidizer shall be at least 99% by weight. [District Rule 2201]
8. Natural gas combustion emissions from the regenerative thermal oxidizer serving the material transfer operations shall not exceed any of the following: 5 ppmvd NOx @ 3% O2 or 0.0062 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0038 lb-CO/MMBtu, and 0.0055 lb-VOC/MMBtu. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST 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
N-9742-23-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

9. The heat input from the process gas (not including the supplemental natural gas) routed to the regenerative thermal oxidizer shall not exceed 792 MMBtu/day and shall not exceed 1,122 MMBtu/rolling 12-month period. [District Rule 2201]

10. Process gas combustion emissions from the regenerative thermal oxidizer serving the material transfer operations shall not exceed any of the following: 5 ppmv NOx @ 3% O2 or 0.0058 lb-NOx/MMBtu, 0.0106 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0035 lb-CO/MMBtu, and 0.0106 lb-VOC/MMBtu. [District Rule 2201]

11. The sulfur content of process gas routed to the regenerative thermal oxidizer shall not exceed 1.75 grains/100 dscf. [District Rule 2201]

12. The quantity of disconnects associated with the transfer of feedstocks shall not exceed 120 in any one day and 20,000 in any rolling 12-month period. [District Rule 2201]

13. Emissions from disconnects associated with the transfer of feedstocks shall not exceed 0.021 lb-VOC/disconnect. [District Rule 2201]

14. The quantity of disconnects associated with the transfer of renewable diesel and sustainable aviation fuel shall not exceed 120 in any one day and 20,000 in any rolling 12-month period. [District Rule 2201]

15. Emissions from disconnects associated with the transfer of renewable diesel and sustainable aviation fuel shall not exceed 0.017 lb-VOC/disconnect. [District Rule 2201]

16. The quantity of disconnects associated with the transfer of naphtha shall not exceed 6 in any one day and 757 in any rolling 12-month period. [District Rule 2201]

17. Emissions from disconnects associated with the transfer of naphtha shall not exceed 0.017 lb-VOC/disconnect. [District Rule 2201]

18. VOC emissions from organic liquid loading operations shall not exceed 0.015 pound per 1,000 gallons of organic liquid loaded. [District Rule 4624]

19. Total fugitive VOC emissions from the material transfer operations shall not exceed 1.0 lb/day and 374 lb/rolling 12-month period. [District Rule 2201]

20. Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]

21. Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rule 2201]

22. Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]

23. Source testing to demonstrate compliance with the VOC limit (lb/1000 gal) shall be performed within 60 days of startup and at least once every 60 months thereafter. Source testing shall be performed using 40 CFR 60.503 "Test Methods and Procedures" and EPA Methods 2A, 2B, 25A and 25B and ARB Method 422, or ARB Test Procedure TP-203.1. [District Rules 2201 and 4624]

24. Source testing to measure NOx, VOC (at thermal oxidizer inlet), VOC (at thermal oxidizer outlet), and VOC control efficiency of the thermal oxidizer shall be conducted within 60 days of startup and every 60 months thereafter. [District Rule 2201]

25. The following test methods shall be used for testing of the regenerative thermal oxidizer: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; VOC (ppmv or lb/MMBtu) - EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4 and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

26. Fuel H2S, total sulfur, and methane content for the process gas routed to the regenerative thermal oxidizer shall be determined annually using the following test methods H2S: ASTM D6228; total sulfur: ASTM D1072; ASTM D3246, or ASTM D6228; and methane content: ASTM D1945. The operation shall keep records of the results of the annual testing of the process gas. [District Rule 2201]

27. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rule 2201]

28. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

29. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

30. The regenerative thermal oxidizer shall be operated with a combustion chamber temperature of no less than 1400 degrees F and the retention time shall be no less than 0.5 seconds. A continuous temperature monitoring and recording device shall be used and kept in good working order. [District Rule 2201]

31. The regenerative thermal oxidizer shall be heated to proper operating temperature prior to any process air entering the oxidizer. [District Rule 2201]

32. The vapor collection and control system associated with this permit shall operate such that the pressure in the delivery tank being loaded does not exceed 18 inches water column pressure and 6 inches water column vacuum. [District Rule 4624]

33. The loading rack(s) shall be equipped with dry break couplers and the transfer rack and vapor collection system shall be designed such that there are no leaks and no excess liquid drainage at disconnect. [District Rules 2201 and 4624]

34. The operator of an organic liquid transfer facility must inspect the vapor collection system and vapor disposal system, and each transfer rack handling organic liquids for leaks during transfer at least once every quarter using a portable hydrocarbon detection instrument in accordance with EPA Method 21. [District Rule 4624]

35. All equipment that are found leaking shall be repaired or replaced within 72 hours. If the leaking component cannot be repaired or replaced within 72 hours, the component shall be taken out of service until such time the component is repaired or replaced. The repaired or replaced equipment shall be re-inspected the first time the equipment is in operation after the repair or replacement. [District Rule 4624]

36. Except for inaccessible components and unsafe to monitor components, the owner or operator shall audio-visually inspect (by hearing and by sight) all hatches, pressure-relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours. Owners or operators shall audio-visually inspect all pipes for leaks or indications of leaks at least once every 12 months. [District Rule 4623]

37. Any component with an audio-visual inspection that indicates a leak shall be tested using US EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance with the repair timeframes specified in this permit. [District Rule 4624]

38. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag. The tag shall include 1) Date and time of leak detection, 2) Date and time of leak measurement, 3) For gaseous leaks, the leak concentration in ppmv, and 4) for liquid leaks, the dripping rate of the liquid. The tag shall remain affixed to the component until all of the following conditions are met: 1) The leaking component has been repaired or replaced, 2) The component has been re-inspected using a portable hydrocarbon detection instrument in accordance with EPA Method 21, and 3) The component is found to be in compliance with the requirements of District Rule 4624. [District Rule 4624]

CONDITIONS CONTINUE ON NEXT PAGE

39. The operator shall maintain an inspection log containing, at a minimum, the following: 1) Total number of components inspected and total number and percentage of leaking components found during inspection; 2) Location, type, name, or description of each leaking component and description of any unit where the leaking component is found, 3) Date of leak detection and method of leak detection, 4) For gas leaks, record the leak concentration in ppmv, and for liquid leaks record the volume, 5) Date of repair, replacement, or removal from operation of leaking components, 6) After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv, 7) Inspector's name, business mailing address, and business telephone number, 8) The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log, 9) Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components including a copy of the gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4624]

40. The operator shall keep records of the daily liquid throughput and the results of any required leak inspections. [District Rule 4624]

41. The permittee shall keep a record of the regenerative thermal oxidizer temperature readings collected from the data recorder on a daily basis. [District Rule 2201]

42. The permittee shall keep a record of the quantity of process gas (in MMBtu) processed each day and a record of the cumulative quantity of process gas (in MMBtu) processed in each rolling 12-month period. [District Rule 2201]

43. The permittee shall keep a record of the quantity of disconnects in each day and on a rolling 12-month basis for the following; 1) the transfer of feedstocks; 2) the transfer renewable diesel and sustainable aviation fuel; and 3) for the transfer of naphtha. [District Rule 2201]

44. The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]

45. All records shall be retained for a minimum of five years and shall be made readily available to the APCO, ARB, or EPA upon request. [District Rules 2201 and 4624]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-24-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
WASTEWATER TREATMENT UNIT VENTED TO A SHARED THERMAL OXIDIZER (RTO #1 SHARED WITH N-9742-21-0) WITH A 7.6 MMBTU/HR NATURAL GAS-FIRED BURNER

CONDITIONS

1. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
2. {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]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. For the regenerative thermal oxidizer, 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]
5. The regenerative thermal oxidizer shall only be fired on PUC-Quality natural gas as a supplemental fuel. [District Rule 2201]
6. The VOC control efficiency of the regenerative thermal oxidizer shall be at least 99% by weight. [District Rule 2201]
7. Natural gas combustion emissions from the regenerative thermal oxidizer serving the material transfer operations shall not exceed any of the following: 5 ppmvd NOx @ 3% O2 or 0.0062 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0038 lb-CO/MMBtu, and 0.0055 lb-VOC/MMBtu. [District Rule 2201]
8. The heat input from the process gas into the regenerative thermal oxidizer shall not exceed 270 MMBtu/day and shall not exceed 270 MMBtu/rolling 12-month period. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST 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
N-9742-24-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

9. Process gas combustion emissions from the regenerative thermal oxidizer serving the hydrogen production unit and the wastewater treatment plant (N-9742-24) shall not exceed any of the following: 5 ppmv NOx @ 3% O2 or 0.0061 lb-NOx/MMBtu, 0.0106 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 0.0035 lb-CO/MMBtu, and 0.0106 lb-VOC/MMBtu. [District Rule 2201]

10. The sulfur content of process gas routed to the regenerative thermal oxidizer shall not exceed 1.75 grains/100 scf. [District Rule 2201]

11. Total fugitive VOC emissions from the hydrogen production unit shall not exceed 1.4 lb/day and 535 lb/rolling 12-month period. [District Rule 2201]

12. Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]

13. Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rule 2201]

14. Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]

15. Source testing to measure NOx, VOC (at thermal oxidizer inlet), VOC (at thermal oxidizer outlet), and VOC control efficiency of the thermal oxidizer shall be conducted within 60 days of startup and annually thereafter. [District Rule 2201]

16. The following test methods shall be used for testing of the regenerative thermal oxidizer: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; VOC (ppmv or lb/MMBtu) - EPA Method 18 or EPA Method 25; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4 and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201]

17. Fuel H2S, total sulfur, and methane content for the process gas routed to the regenerative thermal oxidizer shall be determined annually using the following test methods H2S: ASTM D6228; total sulfur: ASTM D1072; ASTM D3246, or ASTM D6228; and methane content: ASTM D1945. The operator shall keep records of the process gas testing results. [District Rule 2201]

18. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rules 2201]

19. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 2201]

20. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

21. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

22. The regenerative thermal oxidizer shall be operated with a combustion chamber temperature of no less than 1400 degrees F and the retention time shall be no less than 0.5 seconds. A continuous temperature monitoring and recording device shall be used and kept in good working order. [District Rule 2201]

23. The regenerative thermal oxidizer shall be heated to proper operating temperature prior to any process air entering the oxidizer. [District Rule]

24. The operator shall not use any component that leaks in excess of the leak limits of this permit, except as follows. A component identified as leaking in excess of the leak limits of this permit may be used provided it has been identified with a tag for repair, has been repaired, or is awaiting re-inspection after repair, within the applicable time period specified within Rule 4455. [District Rules 2201 and 4405]

CONDITIONS CONTINUE ON NEXT PAGE

25. Each hatch shall be closed at all times except during sampling or adding of process material through the hatch, or during attended repair, replacement, or maintenance operations, provided such activities are done as expeditiously as possible and with minimal spillage of material and VOC emissions to the atmosphere. [District Rule 4455]

26. The owner or operator shall audio-visually inspect (by hearing and sight) all accessible operating pumps, compressors and pressure relief devices for leaks at least once every 24 hours, except when operators do not report to the facility for that given 24 hours. [District Rule 4455]

27. Any audio-visual inspection of all accessible operating pumps, compressors, and pressure relief devices in service that indicates a leak that cannot be immediately repaired to meet the leak requirements of this permit shall be inspected to determine the gaseous leak concentration using an instrument in accordance with EPA Method 21 not later than 24 hours after conducting the audio-visual inspection. If the gas leak concentration is greater than 50,000 ppmv (as methane), the leak must be repaired within 2 calendar days. If the gas leak concentration is greater than the gas leak concentration is greater than 10,000 ppmv but equal to or less than 50,000 ppmv (as methane), the leak must be repaired 3 calendar days. If the leak is greater than the leak concentrations allowed in this permit but less than or equal to 10,000 ppmv (as methane), then the leak must be repaired within 7 calendar days. [District Rule 4455]

28. The operator shall inspect all components at least once every calendar quarter using an instrument in accordance with EPA Method 21, except for inaccessible components and unsafe-to-monitor components, or pipes. [District Rule 4455]

29. The operator shall inspect, immediately after placing into service, all new, replaced, or repaired fittings, flanges, and threaded connections using an instrument in accordance with EPA Method 21. [District Rule 4455]

30. The operator shall inspect all inaccessible components at least once every 12 months using an instrument in accordance with EPA Method 21. [District Rule 4455]

31. The operator shall inspect all unsafe-to-monitor components during each turnaround using an instrument in accordance with EPA Method 21. [District Rule 4455]

32. The operator shall perform an audio-visual inspection on all pipes for leaks at least every 12 months. Any visual inspection of pipes that indicates a leak that cannot be immediately repaired to meet the leak standards of this permit shall be inspected using an instrument in accordance with EPA Method 21 within 24 hours after conducting the audio-visual inspection. If there is a visible mist or continuous flow of liquid that is not seal lubricant from the pipe, the leak must be fixed within 2 calendar days of detection. If there is a liquid leak, except seal lubricant, that is not a visible mist or continuous flow and drips liquid at a rate of more than three drops per minute, the leak shall be fixed within 3 calendar days of detection. [District Rule 4455]

33. The operator shall initially inspect a process pressure relief device that releases to the atmosphere as soon as practicable but no later than 24 hours after the time of release. The operator shall re-inspect the process pressure relief device using an instrument in accordance with EPA Method 21 no earlier than 24 hours after the initial inspection but no later than 15 calendar days after the date of the release to insure that the process pressure relief device is operating properly and is leak free. If the pressure relief device is found to be leaking at either inspection, the pressure relief device leak shall be treated as if the leak was found during quarterly inspections. [District Rule 4455]

34. Except for process pressure relief devices, a component shall be inspected using an instrument in accordance with EPA Method 21 within 15 calendar days after repairing the leak or replacing the component. [District Rule 4455]

35. A District inspection in no way fulfills any of the mandatory inspection requirements placed upon the operator and cannot be used or counted as an inspection required of an operator. Any attempt by an operator to count such District inspections as part of the mandatory operator's inspections is considered a willful circumvention of the Rule 4455 and is a violation of Rule 4455. [District Rule 4455]

36. Upon detection of a leaking component, the operator shall affix to that component a weatherproof readily visible tag. The tag shall include the following information: 1) Date and time of leak detection; 2) Date and time of leak measurement; 3) for gas leaks, indicate the leak concentration in ppmv; 4) for liquid leaks, indicate whether the leak is a Major leak (a leak with visible mist or a continuous flow that is not seal lubricant) or a minor leak (a liquid leak that is not a Major leak, but is in excess of three drops per minute); and 5) For essential components, unsafe-to monitor components, and critical components, indicate so on the tag. The tag shall remain affixed to the component until all of the following conditions are met: 1) the leaking component has been repaired or replace; 2) The component has been re-inspected using an instrument in accordance with EPA Method 21; and 3) The component is found to be in compliance with the leak requirements of this permit. [District Rule 4455]

CONDITIONS CONTINUE ON NEXT PAGE

37. The operator shall minimize all component leaks immediately to the extent possible, but not later than one hour after detection of the leaks in order to stop or reduce leakage to the atmosphere. If the leak has been minimized but the leak still exceeds the applicable leak standards in this permit, the operator shall comply with at least one of the following as soon as possible: 1) Repair or replace the leaking component; or 2) Vent the leaking component to a closed vent system; or 3) Remove the leaking component from service. The leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in Table 3 of Rule 4455. The start of the repair period shall be the time of the initial leak detection. [District Rule 4455]

38. If a leaking component is an essential component or a critical component and which cannot be immediately shutdown for repairs, the operator shall: 1) Minimize the leak within one hour after detection; and 2) If the leak has been minimized, but the leak still exceeds any of the applicable leak standards of this permit, the essential component or critical component shall be repaired or replaced to eliminate the leak during the next process unit turnaround, but in no case later than one year from the date of the original leak detection, whichever comes earlier. [District Rule 4455]

39. For any component that has incurred five repair actions for major gas leaks (> 10,000 ppmv) or major liquid leaks (a visible mist or continuous flow of liquid that is not seal lubricant), or a combination of major gas leaks and major liquid leaks in a continuous 12 month period, the operator shall comply with at least one of the following: 1) Replace or retrofit the component with the control technology specified in Table 4 of Rule 4455 and notify the APCO in writing prior to replacing or retrofitting the component; or 2) Replace the component with Achieved-in-Practice Best Available Control Technology (BACT) equipment, as determined in accordance with District Rule 2201 and as approved by the APCO in writing; or 3) Vent the component to an APCO approved closed vent system or 4) Remove the component from operation. For any component that is accessible, is not unsafe-to-monitor, is not an essential component, and is not a critical component, the operator shall perform one of the above four actions as soon as practicable, but no later than 12 months after the date of detection of the fifth major leak in a continuous 12-month period. For any inaccessible component, unsafe-to-monitor component, essential component, or critical component, the operator shall perform one of the above four actions as soon as practicable but not later than the next turnaround or not later than 2 years after the date of detection of the fifth major component leak within a continuous 12-month period. An entire compressor or pump need not be replaced provided the compressor parts or pump parts that incurred five repair action are brought into compliance. [District Rule 4455]

40. The operator shall monitor process pressure relief devices using electronic process control instrumentation that allows for real time continuous parameter monitoring or by using telltale indicators for the process pressure relief device where parameter monitoring is not feasible. [District Rule 4455]

41. The operator shall submit a compliance plan as part of the Operator Management Plan containing an inventory of process pressure relief devices by size, set pressure and location, and the type of monitoring system used. If applicable, the operator shall indicate the process parameter selected for continuous monitoring and justification for such selection. [District Rule 4455]

42. After the release from process pressure relief device in excess of 500 pounds of VOC in a continuous 24-hour period, the operator shall immediately conduct a failure analysis and implement corrective actions as soon as practicable, but no later than 30 days, to prevent the reoccurrence of such release. [District Rule 4455]

43. All major components and critical components shall be physically identified clearly and visibly for inspection, repair, and recordkeeping purposes. The physical identification shall consist of labels, tags, manufacturer's nameplate identifier, serial number, or model number, or other system approved by the APCO that enables an operator and District personnel to locate each individual component. The operator shall replace tags or labels that become missing or unreadable as soon as practicable but no later than 24 hours after discovery. [District Rule 4455]

CONDITIONS CONTINUE ON NEXT PAGE

44. The operator shall submit an Operator Management Plan for approval to the APCO. The operator shall describe in the Operator Management Plan all components Subject to Rule 4455 or exempt pursuant to Subject 4.0. The plan shall contain a descriptions and procedures that the operator will use to comply with the requirements of Rule 4455. The Plan shall include, at a minimum, all of the following information: 1) Identification and description of any known hazard that might affect the safety of an inspector; 2) Diagrams, charts, spreadsheets, or other methods approved by the APCO which describe the following: 2a) Except for pipes, the number of components that are subject to Rule 4455 by component type and type of service (liquid or gas); 2b) Except for pipes, the number and types of major components, inaccessible components, unsafe-to-monitor components, critical components, and essential components that are subject to Rule 4455 including the reasons for such designation; 2c) Except for pipes, the location of components that are subject to this rule (components may be grouped together functionally by process unit or facility description; 2d) Except for pipes components exempt pursuant to Section 4.2 (except for components buried below ground) may be described by grouping them functionally by process unit or facility description. The results of any laboratory testing or other pertinent information to demonstrate compliance with the exemption criteria for components shall be submitted with the Operator Management Plan; 3) Detailed schedule of inspection to be conducted as required by Rule 4455; 4) Include the compliance plan for process pressure relief devices as required by Rule 4455; 5) Specify whether a qualified contractor or in-house team will perform inspections; 6) Establish an employee training program for inspecting, repairing, and recordkeeping procedures; 6a) Specify the training standards for personnel performing inspections and repairs; 6b) document the leak detection training using instruments in accordance with EPA Method 21. The operator shall maintain records of the Operator management plant and training records at the facility. Copies of such records shall be made available to the APCO, ARB, and US EPA upon request. [District Rule 4455]

45. By January 30 of each year, the operator shall submit to the APCO for approval, in writing, an annual report indicating any changes to the existing Operator Management Plan. [District Rule 4455]

46. The District shall provide written notice of the approval or incompleteness of a new or revised Operator Management Plan within 60 days of receiving such Plan. If the District fails to respond in writing within 60 days after the date of receiving the Plan, it shall be deemed approved. No provision of the Plan, approved or not, shall conflict with or take precedence over any provision of Rule 4455. [District Rule 4455]

47. The operator shall maintain an inspection log containing the following: 1) Total number of components inspected, and total number and percentage of leaking components found by component type; 2) Location, type, name or description of each leaking component, and description of any unit where the leaking component is found; 3) Date of leak detection and method of leak detection; 4) For gaseous leaks, the concentration in ppmv, and for liquid leaks, whether the liquid leak is a major leak (a visible mist or continuous flow of liquid that is not seal lubricant) or a minor leak (a liquid leak, except seal lubricant, that is not a major liquid leak and drips liquid at a rate of more than three drops per minute); 5) Date of repair, replacement, or removal from operation of leaking components; 6) Identification and location of essential component and critical components found leaking that cannot be repaired until the next process turnaround or not later than one year after leak detection, whichever comes earlier; 7) Methods used to minimize the leak from essential components and critical components that cannot be repaired until the next process unit turnaround or not later than one year after leak detection, whichever comes later; 8) After the component is repaired or replaced, the date of re-inspection and the leak concentration in ppmv; 9) Inspectors name, business mailing address, and business telephone number; and 10) The facility operator responsible for inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log. [District Rule 4455]

48. Records of leaks detected by quarterly or annual operator inspection and each subsequent repair and re-inspection shall be submitted to the APCO, ARB, or USA upon request. [District Rule 4455]

49. Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components, including a copy of the current calibration gas certification from the vendor of said calibration gas, analyzer reading of calibration gas before adjustment, instrument reading of calibration gas after adjustment, caliber gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4455]

50. The operator shall notify the District, by telephone or other methods approved by the District, of any process pressure relief device release. [District Rule 4455]

CONDITIONS CONTINUE ON NEXT PAGE

51. The operator shall submit a written report to the District within 30 calendar days following the notification of a process pressure release device release. The report shall include the following: 1) Process pressure release device type, size and location; 2) Date, time, and duration of process pressure relief device release; 3) Types of VOC release and individual amounts, in pounds, including supporting calculations; 4) Cause of the pressure release device release; and 5) Corrective actions taken to prevent a subsequent pressure release device release. [District Rule 4455]

52. The operator shall keep records of the process parameters monitored for pressure release devices. [District Rule 4455]

53. Measurements of gaseous leak concentrations using EPA Method 21 shall be made using an appropriate portable hydrocarbon detection instrument calibrated with methane. The instrument shall be calibrated in accordance with US EPA Method 21 or the manufacturer's instructions, as appropriate, not more than 30 days prior to its use. The operator shall record the calibration date of the instrument. [District Rule 4455]

54. After June 30, 2024, all leaks detected with the use of an OGI instrument shall be measured using EPA Reference Method 21 within two calendar days of initial OGI leak detection, or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component do determine compliance with the leak thresholds and repair timeframes specified in Table 5 of Rule 4455. [District Rule 4455]

55. The permittee shall keep a record of the regenerative thermal oxidizer temperature readings collected from the data recorder on a daily basis. [District Rule 2201]

56. The permittee shall keep a record of the quantity of process gas (in MMBtu) processed each day by the regenerative thermal oxidizer and a record of the cumulative quantity of process gas (in MMBtu) processed in each rolling 12-month period by the regenerative thermal oxidizer. [District Rule 2201]

57. The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]

58. All records shall be retained for a minimum of five years and shall be made available to the District, ARB, or US EPA upon request. [District Rules 2201 and 4455]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-25-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
10,200 GALLONS PER MINUTE THREE-CELL COOLING TOWER WITH A DRIFT ELIMINATOR

CONDITIONS

1. {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]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]
4. The cooling tower shall be equipped with a drift eliminator that reduces drift to less than or equal to 0.0005%. [District Rule 2201]
5. PM10 emissions from the cooling tower shall not exceed 0.4 pounds in any one day. [District Rule 2201]
6. Compliance with the daily emissions limitation shall be demonstrated on a quarterly basis using the daily PM10 emission rate calculated as follows: blowdown water TDS (ppmv) ÷ 10^6 x cooling water recirculation rate (gal/day) x design drift rate (%) ÷ 100 x water density (lb/gal). [District Rules 1070 and 2201]
7. Total Dissolved Solids (TDS) in the blowdown water shall be sampled and analyzed using a conductivity analyzer at least quarterly. [District Rule 2201]
8. The water recirculation rate shall be measured and recorded at least quarterly. [District Rule 2201]
9. The operator shall maintain records of all circulating water tests performed. Records shall be maintained for at least 5 years and shall be made available to the District upon request. [District Rule 2201]

YOU MUST 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
N-9742-25-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-26-0 **ISSUANCE DATE:** DRAFT

DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
79.17 MMBTU/HR PROCESS GAS-FIRED EMERGENCY FLARE

CONDITIONS

1. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
2. {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]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {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]
5. This flare shall only be operated during an emergency. An emergency is any situation or condition arising from a sudden or reasonably unforeseeable and unpreventable event beyond the control of the operator. Examples include, but are not limited 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 quality as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered an emergency. [District Rule 4311]
6. The emergency flare shall only be fired on PUC-Quality natural gas as a supplemental fuel. [District Rule 2201]
7. The heat input for the emergency flare shall not exceed 1,900 MMBtu in any one day and shall not exceed 7,400 MMBtu in any rolling 12-month period. [District Rules 2201 and 4102]

CONDITIONS CONTINUE ON NEXT PAGE

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Brian Clements, Director of Permit Services
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8. Emissions from the emergency flare shall not exceed any of the following: 0.0068 lb-NOx/MMBtu, 0.0152 lb-SOx/MMBtu, 0.05 lb-PM10/MMBtu, 0.37 lb-CO/MMBtu, and 0.14 lb-VOC/MMBtu. [District Rule 2201]
9. The flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311]
10. 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]
11. 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]
12. The owner or operator shall keep a record of the duration of flare operation, the amount of gas burned, and the nature of the emergency situation that required flaring to occur. [District Rule 4311]
13. The owner or operator shall keep a record of all flare monitoring data required by this permit. [District Rule 4311]
14. The operator shall keep a record of the daily heat input to the flare and shall keep a record of the cumulative rolling 12-month heat input to the flare. [District Rule 2201]
15. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available to the District, ARB, or EPA upon request. [District Rule 2201]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-27-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
687 BHP (INTERMITTENT) CLARKE MODEL C18H0 TIER 3 CERTIFIED DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIREWATER PUMP

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
3. {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]
4. {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]
5. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]
6. {4749} This engine shall be equipped with a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District determines that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history. [District Rule 4702 and 17 CCR 93115]
7. Emissions from this engine shall not exceed any of the following limits: 2.65 g-NOx/bhp-hr, 0.92 g-CO/bhp-hr, or 0.06 g-VOC/bhp-hr. [District Rule 2201 and 17 CCR 93115]
8. PM10 emission rate from this engine shall not exceed 0.087 g/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 17 CCR 93115]

CONDITIONS CONTINUE ON NEXT PAGE

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Samir Sheikh, Executive Director / APCO

DRAFT

Brian Clements, Director of Permit Services
N-9742-27-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

Conditions for N-9742-27-0 (continued)

9. The engine shall be operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood. [District Rule 4702 and 17 CCR 93115]

10. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems". Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 100 hours per calendar year. [District Rules 2201, 4102 and 4702, and 17 CCR 93115]

11. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rules 2201 and 4702 and 17 CCR 93115]

12. {4263} The permittee shall maintain monthly records of the type of fuel purchased. [District Rule 4702 and 17 CCR 93115]

13. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-28-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
1,341 BHP (INTERMITTENT) CUMMINS MODEL DQFAD TIER 4F CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. {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]
3. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. {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]
5. {4749} This engine shall be equipped with a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District determines that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history. [District Rule 4702 and 17 CCR 93115]
6. {4258} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801, and 17 CCR 93115]
7. Emissions from this IC engine shall not exceed any of the following limits: 0.5 g-NOx/bhp-hr, 2.0 g-CO/bhp-hr, or 0.14 g-VOC/bhp-hr. [District Rule 2201 and 17 CCR 93115]
8. Emissions from this IC engine shall not exceed 0.022 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102, and 17 CCR 93115]

CONDITIONS CONTINUE ON NEXT PAGE

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Samir Sheikh, Executive Director / APCO

DRAFT

Brian Clements, Director of Permit Services
N-9742-28-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

9. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

10. {3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

11. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702 and 17 CCR 93115]

12. {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702 and 17 CCR 93115]

13. {3496} 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, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

14. {4920} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rules 2201, 4102, and 4702, and 17 CCR 93115]

15. {4263} The permittee shall maintain monthly records of the type of fuel purchased. [District Rule 4702 and 17 CCR 93115]

16. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-29-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
203,700 GALLON NAPHTHA STORAGE TANK WITH AN INTERNAL FLOATING ROOF A MECHANICAL-SHOE PRIMARY SEAL AND A WIPER SECONDARY SEAL

CONDITIONS

1. {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]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Only Naphtha shall be stored in this tank. The true vapor pressure of the Naphtha shall not exceed 11 psia. [District Rules 2201 and 4623, and 40 CFR 60.]
4. VOC emissions from this tank shall not exceed 3.9 lb in any one day and shall not exceed 1,421 lb in any one rolling 12-month period. [District Rule 2201]
5. The quantity of naphtha loaded into this tank shall not exceed 203,700 gallons in any one day and shall not exceed 10,567,956 gallons in any rolling 12-month period. [District Rule 2201]
6. Total combined fugitive VOC emissions from components such as valves, flanges, connectors, pump seals, etc., associated with tanks N-9742-29, '-30, '-31, and '-32, shall not exceed 1.0 lb/day and 375 lb/rolling 12-month period. [District Rule 2201]
7. Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

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Samir Sheikh, Executive Director / APCO

DRAFT

Brian Clements, Director of Permit Services
N-9742-29-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

8. Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]
9. Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rules 2201 and 4623]
10. Gaps between the tank shell and the primary seal shall not exceed 1 1/2 inches. [District Rule 4623]
11. The cumulative length of all gaps between the tank shell and the primary seal greater than 1/2 inch shall not exceed 10% of the circumference of the tank. [District Rule 4623]
12. The cumulative length of all primary seal gaps greater than 1/8 inch shall not exceed 30% of the circumference of the tank. [District Rule 4623]
13. No continuous gap in the primary seal greater than 1/8 inch wide shall exceed 10% of the tank circumference. [District Rule 4623]
14. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. [District Rule 4623]
15. The cumulative length all gaps between the tank shell and the secondary seal, greater than 1/8 inch shall not exceed 5% of the tank circumference. [District Rule 4623]
16. The metallic shoe-type seal shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 6 inches above the stored liquid surface. [District Rule 4623]
17. The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell shall be no greater than 3 inches for a length of at least 18 inches in the vertical plane above the liquid. [District Rule 4623]
18. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. [District Rule 4623]
19. The secondary seal shall allow easy insertion of probes of up to 1 1/2 inches in width in order to measure gaps in the primary seal. [District Rule 4623]
20. The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. [District Rule 4623]
21. The internal floating roof shall be floating on the surface of the stored liquid at all times (i.e., off the roof leg supports) except during the initial fill until the roof is lifted off the leg supports and when the tank is completely emptied and subsequently refilled, and for tank interior cleaning, and during tank repair and maintenance activities. When the roof is resting on the leg supports the processes of filling or emptying and refilling shall be continuous and shall be accomplished as rapidly as possible. Whenever the permittee intends to land the roof on its legs, the permittee shall notify the APCO in writing at least five calendar days prior to performing the work. The tank must be in compliance with this rule before it may land the roof on its legs. [District Rules 2020, 2201, and 4623, and 40 CFR 60.112b(a)(1)(i)]
22. All openings in the roof used for sampling and gauging, except pressure-vacuum valves which shall be set to within 10% of the maximum allowable working pressure of the roof, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal or lid that shall be in a closed position at all times, with no visible gaps and be gas tight, except when the device or appurtenance is in use. [District Rule 4623]
23. A leak-free condition is defined as a condition without a gas or liquid leak as defined in this permit. [District Rule 4623]
24. Each opening in a non-contact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents shall provide a projection below the liquid surface. [District Rule 4623 and 40 CFR 60.112b(a)(1)(iii)]

CONDITIONS CONTINUE ON NEXT PAGE

25. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains shall be equipped with a cover, or a lid shall be maintained in a closed position at all times (i.e. no visible gaps) except when the device is in use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted in place except when they are in use. [District Rule 4623 and 40 CFR 60.112b(a)(1)(iv)]

26. Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the leg roof supports. [District Rule 4623 and 40 CFR 60.112b(a)(1)(v)]

27. Rim vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. [District Rule 4623 and 40 CFR 60.112b(a)(1)(vi)]

28. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90 percent of the opening. The fabric cover must be impermeable. [District Rule 4623 and 40 CFR 60.112b(a)(1)(vii)]

29. Each penetration of the internal floating roof that allows for the passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable. [District Rule 4623 and 40 CFR 60.112b(a)(1)(viii)]

30. Each penetration of the internal floating roof that allows for the passage of a ladder shall have a gasketed sliding cover. [40 CFR 60.112b(a)(1)(ix)]

31. All slotted sampling or gauging wells shall provide a projection below the liquid surface. [District Rule 4623]

32. The gap between the pole wiper and the slotted guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed one-eighth inch. [District Rule 4623]

33. The owner or operator shall notify the APCO in writing at least three days prior to performing tank degassing and interior tank cleaning activities. The written notification shall include the following: 1) The PTO number and physical location of the tank being degassed, 2) The date and time that tank degassing and cleaning activities will begin, 3) The degassing method to be used, 4) The method that will be used to clean the tank, including any solvents to be used, and 5) The method to be used to dispose of the removed sludge including methods that will be used to control emissions during transport. [District Rule 4623]

34. The operator shall maintain records of tank cleaning activities for a period of 5 years and present said records to the APCO upon request. [District Rule 4623]

35. The process of tank degassing shall be accomplished by emptying the tank of organic liquid having a TVP of 0.1 psia or greater and minimizing organic vapors in the tank vapor space by one of the following methods: 1) Exhaust VOCs contained in the tank vapor space to an APCO-approved vapor recovery system until the organic vapor concentration is 5,000 ppmv or less, or is 10 percent or less of the lower explosion limit (LEL), whichever is less; or 2) Displace VOCs contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable liquid until 90 percent or more of the maximum operating level of the tank is filled. Suitable liquids are organic liquids having a TVP of less than 0.1 psia, water, clean produced water, or produced water derived from crude oil having a TVP less than 0.5 psia; or 3) Displace VOC contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable gas. Degassing shall continue until the operator has achieved a vapor displacement equivalent to at least 2.3 times the tank capacity. Suitable gases are air, nitrogen, carbon dioxide, or natural gas containing less than 10 percent VOC by weight. [District Rule 4623]

36. During degassing, the operator shall discharge or displace organic vapors contained in the tank vapor space to an APCO-approved vapor recovery system that is leak free and routes vapors to a VOC control device that reduced the inlet VOC emissions by at least 95 percent by weight. [District Rule 4623]

37. To facilitate connection to an external APCO-approved vapor recovery system during degassing, a suitable fitting such as a manway may be temporarily removed for a period of time not to exceed 1 hour. [District Rule 4623]

38. This tank shall be in compliance with the applicable requirements of District Rule 4623 at all times during draining, degassing, and refilling the tank with an organic liquid having a TVP of 0.1 psia or greater. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

39. During tank cleaning operations, draining and refilling of this tank shall occur as a continuous process and shall proceed as rapidly as practicable while the roof is not floating on the surface of the stored liquid. [District Rule 4623]

40. Gap seal requirements shall not apply while the roof is resting on its legs, and during the processes of draining, degassing, or refilling the tank. A leak-free condition will not be required if the operator is draining or refilling this tank in a continuous, expeditious manner. [District Rule 4623]

41. After a tank has been degassed pursuant to the requirements of this permit, vapor control requirements are not applicable until an organic liquid having a TVP of 0.1 psia or greater is placed, held, or stored in this tank. [District Rule 4623]

42. While performing tank cleaning activities, operators may only use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 degrees F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams of VOC per liter or less. [District Rule 4623]

43. Steam cleaning shall only be allowed at locations where wastewater treatment facilities are limited, or during the months of December through March. [District Rule 4623]

44. During sludge removal, the operator shall control emissions from the sludge receiving vessel by operating an APCO-approved vapor control device that reduces emissions of organic vapors by at least 95%. [District Rule 4623]

45. The permittee shall only transport removed sludge in closed, liquid leak-free containers. [District Rule 4623]

46. The permittee shall store removed sludge, until final disposal, in vapor leak-free containers, or in tanks complying with the vapor control requirements of District Rule 4623. Sludge that is to be used to manufacture roadmix, as defined in District Rule 2020, is not required to be stored in this manner. Roadmix manufacturing operations exempt pursuant to District Rule 2020 shall maintain documentation of their compliance with Rule 2020, and shall readily make said documentation available for District inspection upon request. [District Rule 4623]

47. A leak discovered during operator or District inspection shall be repaired within the following timeframes: within 14 calendar days of discovery for gas leaks less than or equal to 10,000 ppmv, within 2 calendar days of discovery for gas leaks greater than 10,000 ppmv, and within 2 calendar days of discovery for liquid leaks. [District Rule 4623]

48. The operator shall perform periodic component leak inspections once each calendar quarter, except for inaccessible components, unsafe to monitor components and floating roof tanks including their deck fittings and components. Internal floating roof tanks shall be inspected once every 60 months. [District Rule 4623]

49. For periodic component leak inspections, all components shall be tested for leaks of total hydrocarbons in units of parts per million volume (ppmv) in accordance with US EPA Reference Method 21. [District Rule 4623]

50. For periodic component leak inspections, inaccessible components and unsafe to monitor components shall be inspected once every 12 months per US EPA Reference Method 21. [District Rule 4623]

51. For periodic component leak inspections, except for inaccessible components, unsafe to monitor components, and floating roof tanks including deck fittings and components, owners or operators shall audio-visually inspect (by hearing and sight) all hatches, pressure-vacuum relief valves, pressure relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours. [District Rule 4623]

52. For periodic component leak inspections, any audio-visual inspection specified that indicates a leak shall be tested using EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance the leak repair timeframes specified within this permit. [District Rule 4623]

53. For periodic component leak inspections, an operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 24 hours, and leaks shall be repaired in accordance the leak repair timeframes specified within this permit. [District Rule 4623]

54. A District inspection does not fulfill the periodic component leak inspection requirements and cannot be used or counted as an inspection required of the operator. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

55. For periodic leak inspections, upon detection of a component with a leak concentration measured above the limits in this permit, the operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of the leak detection measurement and the measured leak concentration. The tag shall remain affixed to the leaking component until it has been successfully repaired or replaced, after which the tag shall be removed. Successful repair shall be confirmed by re-measuring the components using EPA Reference Method 21 to determine that the component is below the minimum leak threshold after repair or replacement. [District Rule 4623]

56. For periodic leak inspections, excluding tanks, components or component parts which incur five repair actions within a rolling 12-month period shall be replaced with a compliant component in working order and must be re-measured using EPA Reference Method 21, to determine that the component is below the minimum leak threshold. A record of the replacement shall be maintained in a log at the facility, and shall be made available upon request to the APCO. [District Rule 4623]

57. For periodic leak inspections, the operator shall attempt to minimize all component leaks to the extent possible immediately after detection, but no later than one hour after detection of the leak in order to stop or reduce leakage to the atmosphere. [District Rule 4623]

58. For periodic leak inspections, if the leak has been minimized but the leak still exceeds the applicable leak standards in this permit, the operator shall comply with at least one of the following as soon as practicable, but no later than the time period for repairing the leak as specified in this permit: 1) Repair or replace the leaking component; or 2) Vent the leaking component to a VOC control system as defined in Section 3.1 of District Rule 4623 (6/15/23); or 3) Remove the leaking component from operation. [District Rule 4623]

59. For periodic leak inspections, the leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in this permit. The start of the repair period shall be the time of the initial leak detection. [District Rule 4623]

60. The owner or operator shall submit a tank inspection plan to the APCO for approval. The plan shall include an inventory of the tanks subject to this rule and a tank inspection schedule. A copy of the operator's tank safety procedures shall be made available to the APCO upon request. The tank inventory shall include tank's identification number, PTO number, maximum tank capacity, dimensions of tank (height and diameter), organic liquid stored, type of primary and secondary seal, type of floating roof (internal or external floating roof), construction date of tank, and location of tank. Any revision to a previously approved tank inspection schedule shall be submitted to the APCO for approval prior to conducting an inspection. [District Rule 4623]

61. For newly constructed, repaired, or rebuilt internal floating roof tanks, the permittee shall visually inspect the internal floating roof, and its appurtenant parts, fittings, etc. and measure the gaps of the primary seal and/or secondary seal prior to filling the tank for newly constructed, repair, or rebuilt internal floating roof tanks. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to filling the tank. [District Rule 4623 and 40 CFR 60.113b(a)(1)]

62. The operator shall visually inspect, through the manholes, roof hatches, or other opening on the fixed roof, the internal floating roof and its appurtenant parts, fittings, etc., and the primary seal and/or secondary seal at least once every 12 months after the tank is initially filled with an organic liquid. There should be no visible organic liquid on the roof, tank walls, or anywhere. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of vapors. Any defects found are violations of this rule. [District Rule 4623 and 40 CFR 60.113b(a)(2)]

63. The permittee shall conduct actual gap measurements of the primary seal and/or secondary seal at least once every 60 months. Other than the gap criteria specified by this permit, no holes, tears, or other openings are allowed that would permit the escape of hydrocarbon vapors. Any defects found shall constitute a violation of this rule. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

64. If any failure (i.e. visible organic liquid on the internal floating roof, tank walls or anywhere, holes or tears in the seal fabric) is detected during 12 month visual inspection, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If the detected failure cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the APCO in the inspection report. Such a request must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible. [40 CFR 60.113b(a)(2)]

65. The permittee shall notify the District in writing at least 30 days prior to conduct the visual inspection of the storage vessel, so the District can arrange an observer. [40 CFR 60.113b(a)(5)]

66. The permittee shall furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specification of 40 CFR Part 60.112b(a)(1) and 40 CFR Part 60.113b(a)(1) within 15 days after the initial startup of the equipment. [40 CFR 60.115b(a)(1)]

67. The permittee shall submit the reports of the floating roof tank inspections to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Rule 4623, Sections 5.2 through 5.5. The inspection report for tanks that that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and made available upon request by the APCO. The inspection report shall contain all necessary information to demonstrate compliance with the provisions of this rule, including the following: 1) Date the storage vessel was emptied, date of inspection and names and titles of company personnel doing the inspection. 2) Tank identification number and Permit to Operate number. 3) Observed condition of each component of the control equipment (seals, internal floating roof, and fittings). 4) Measurements of the gaps between the tank shell and primary and secondary seals. 5) Leak free status of the tank and floating roof deck fittings. Records of the leak-free status shall include the vapor concentration values measured in parts per million by volume (ppmv). 6) Data, supported by calculations, demonstrating compliance with the requirements specified in Sections 5.4 and 5.5.2.4.3 of Rule 4623. 7) Nature of defects and any corrective actions or repairs performed on the tank in order to comply with rule 4623 and the date(s) such actions were taken. [District Rule 4623 and 40 CFR 60.115b(a)]

68. The operator shall visually inspect the internal floating roof, the primary seal and/or secondary seal, gaskets, slotted membrane and/or sleeve seals each time the storage tank is emptied and degassed. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to refilling the tank. [40 CFR 60.113b(a)(4)]

69. The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel, and these records shall be kept for the life of the source. [40 CFR 60.116b(b)]

70. The operator shall keep an accurate record of each organic liquid stored in the tank, including storage temperature, TVP, and monthly throughput. [District Rule 4623]

71. The operator shall maintain an inspection log containing, at a minimum, the following: 1) Total number of components inspected and total number and percentage of leaking components found during inspection; 2) Location, type, name, or description of each leaking component and description of any unit where the leaking component is found, 3) Date of leak detection and method of leak detection, 4) For gas leaks, record the leak concentration in ppmv, and for liquid leaks record the volume, 5) Date of repair, replacement, or removal from operation of leaking components, 6) After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv, 7) Inspector's name, business mailing address, and business telephone number, 8) The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log, 9) Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components including a copy of the gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4623]

72. The permittee shall maintain records of the volatile organic liquid stored, the period of storage, and TVP of that volatile organic liquid during the respective storage period. TVP shall be determined using the data on the reid vapor pressure (highest receipt or highest tank sample results) and actual storage temperature. [District Rule 2201 and 40 CFR 60.116b(c)]

CONDITIONS CONTINUE ON NEXT PAGE

73. The permittee shall maintain the records of the internal floating roof landing activities that are performed pursuant to Rule 4623, Section 5.3.1.3 and 5.4.3. The records shall include information on the TVP, API gravity, and type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. [District Rule 4623]

74. The permittee shall keep daily records and annual records on a rolling 12-month period of the quantity of organic liquid loaded into the tank, in gallons. [District Rule 2201]

75. The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]

76. All records shall be maintained on site for a period of at least five years and shall be made available for District, ARB, and EPA inspection upon request. [District Rules 1070, 2201 and 4623, and 40 CFR 60.116b(a)]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-30-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
203,700 GALLON NAPHTHA STORAGE TANK WITH AN INTERNAL FLOATING ROOF A MECHANICAL-SHOE PRIMARY SEAL AND A WIPER SECONDARY SEAL

CONDITIONS

1. {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]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Only Naphtha shall be stored in this tank. The true vapor pressure of the Naphtha shall not exceed 11 psia. [District Rules 2201 and 4623, and 40 CFR 60.]
4. VOC emissions from this tank shall not exceed 3.9 lb in any one day and shall not exceed 1,421 lb in any one rolling 12-month period. [District Rule 2201]
5. The quantity of naphtha loaded into this tank shall not exceed 203,700 gallons in any one day and shall not exceed 10,567,956 gallons in any rolling 12-month period. [District Rule 2201]
6. Total combined fugitive VOC emissions from components such as valves, flanges, connectors, pump seals, etc., associated with tanks N-9742-29, '-30, '-31, and '-32, shall not exceed 1.0 lb/day and 375 lb/rolling 12-month period. [District Rule 2201]
7. Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST 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
N-9742-30-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

8. Component gas leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]
9. Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rules 2201 and 4623]
10. Gaps between the tank shell and the primary seal shall not exceed 1 1/2 inches. [District Rule 4623]
11. The cumulative length of all gaps between the tank shell and the primary seal greater than 1/2 inch shall not exceed 10% of the circumference of the tank. [District Rule 4623]
12. The cumulative length of all primary seal gaps greater than 1/8 inch shall not exceed 30% of the circumference of the tank. [District Rule 4623]
13. No continuous gap in the primary seal greater than 1/8 inch wide shall exceed 10% of the tank circumference. [District Rule 4623]
14. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. [District Rule 4623]
15. The cumulative length all gaps between the tank shell and the secondary seal, greater than 1/8 inch shall not exceed 5% of the tank circumference. [District Rule 4623]
16. The metallic shoe-type seal shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 6 inches above the stored liquid surface. [District Rule 4623]
17. The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell shall be no greater than 3 inches for a length of at least 18 inches in the vertical plane above the liquid. [District Rule 4623]
18. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. [District Rule 4623]
19. The secondary seal shall allow easy insertion of probes of up to 1 1/2 inches in width in order to measure gaps in the primary seal. [District Rule 4623]
20. The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. [District Rule 4623]
21. The internal floating roof shall be floating on the surface of the stored liquid at all times (i.e., off the roof leg supports) except during the initial fill until the roof is lifted off the leg supports and when the tank is completely emptied and subsequently refilled, and for tank interior cleaning, and during tank repair and maintenance activities. When the roof is resting on the leg supports the processes of filling or emptying and refilling shall be continuous and shall be accomplished as rapidly as possible. Whenever the permittee intends to land the roof on its legs, the permittee shall notify the APCO in writing at least five calendar days prior to performing the work. The tank must be in compliance with this rule before it may land the roof on its legs. [District Rules 2020, 2201, and 4623, and 40 CFR 60.112b(a)(1)(i)]
22. All openings in the roof used for sampling and gauging, except pressure-vacuum valves which shall be set to within 10% of the maximum allowable working pressure of the roof, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal or lid that shall be in a closed position at all times, with no visible gaps and be gas tight, except when the device or appurtenance is in use. [District Rule 4623]
23. A leak-free condition is defined as a condition without a gas or liquid leak as defined in this permit. [District Rule 4623]
24. Each opening in a non-contact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents shall provide a projection below the liquid surface. [District Rule 4623 and 40 CFR 60.112b(a)(1)(iii)]

CONDITIONS CONTINUE ON NEXT PAGE

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26. Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the leg roof supports. [District Rule 4623 and 40 CFR 60.112b(a)(1)(v)]

27. Rim vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. [District Rule 4623 and 40 CFR 60.112b(a)(1)(vi)]

28. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90 percent of the opening. The fabric cover must be impermeable. [District Rule 4623 and 40 CFR 60.112b(a)(1)(vii)]

29. Each penetration of the internal floating roof that allows for the passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable. [District Rule 4623 and 40 CFR 60.112b(a)(1)(viii)]

30. Each penetration of the internal floating roof that allows for the passage of a ladder shall have a gasketed sliding cover. [40 CFR 60.112b(a)(1)(ix)]

31. All slotted sampling or gauging wells shall provide a projection below the liquid surface. [District Rule 4623]

32. The gap between the pole wiper and the slotted guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed one-eighth inch. [District Rule 4623]

33. The owner or operator shall notify the APCO in writing at least three days prior to performing tank degassing and interior tank cleaning activities. The written notification shall include the following: 1) The PTO number and physical location of the tank being degassed, 2) The date and time that tank degassing and cleaning activities will begin, 3) The degassing method to be used, 4) The method that will be used to clean the tank, including any solvents to be used, and 5) The method to be used to dispose of the removed sludge including methods that will be used to control emissions during transport. [District Rule 4623]

34. The operator shall maintain records of tank cleaning activities for a period of 5 years and present said records to the APCO upon request. [District Rule 4623]

35. The process of tank degassing shall be accomplished by emptying the tank of organic liquid having a TVP of 0.1 psia or greater and minimizing organic vapors in the tank vapor space by one of the following methods: 1) Exhaust VOCs contained in the tank vapor space to an APCO-approved vapor recovery system until the organic vapor concentration is 5,000 ppmv or less, or is 10 percent or less of the lower explosion limit (LEL), whichever is less; or 2) Displace VOCs contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable liquid until 90 percent or more of the maximum operating level of the tank is filled. Suitable liquids are organic liquids having a TVP of less than 0.1 psia, water, clean produced water, or produced water derived from crude oil having a TVP less than 0.5 psia; or 3) Displace VOC contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable gas. Degassing shall continue until the operator has achieved a vapor displacement equivalent to at least 2.3 times the tank capacity. Suitable gases are air, nitrogen, carbon dioxide, or natural gas containing less than 10 percent VOC by weight. [District Rule 4623]

36. During degassing, the operator shall discharge or displace organic vapors contained in the tank vapor space to an APCO-approved vapor recovery system that is leak free and routes vapors to a VOC control device that reduced the inlet VOC emissions by at least 95 percent by weight. [District Rule 4623]

37. To facilitate connection to an external APCO-approved vapor recovery system during degassing, a suitable fitting such as a manway may be temporarily removed for a period of time not to exceed 1 hour. [District Rule 4623]

38. This tank shall be in compliance with the applicable requirements of District Rule 4623 at all times during draining, degassing, and refilling the tank with an organic liquid having a TVP of 0.1 psia or greater. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

39. During tank cleaning operations, draining and refilling of this tank shall occur as a continuous process and shall proceed as rapidly as practicable while the roof is not floating on the surface of the stored liquid. [District Rule 4623]

40. Gap seal requirements shall not apply while the roof is resting on its legs, and during the processes of draining, degassing, or refilling the tank. A leak-free condition will not be required if the operator is draining or refilling this tank in a continuous, expeditious manner. [District Rule 4623]

41. After a tank has been degassed pursuant to the requirements of this permit, vapor control requirements are not applicable until an organic liquid having a TVP of 0.1 psia or greater is placed, held, or stored in this tank. [District Rule 4623]

42. While performing tank cleaning activities, operators may only use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 degrees F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams of VOC per liter or less. [District Rule 4623]

43. Steam cleaning shall only be allowed at locations where wastewater treatment facilities are limited, or during the months of December through March. [District Rule 4623]

44. During sludge removal, the operator shall control emissions from the sludge receiving vessel by operating an APCO-approved vapor control device that reduces emissions of organic vapors by at least 95%. [District Rule 4623]

45. The permittee shall only transport removed sludge in closed, liquid leak-free containers. [District Rule 4623]

46. The permittee shall store removed sludge, until final disposal, in vapor leak-free containers, or in tanks complying with the vapor control requirements of District Rule 4623. Sludge that is to be used to manufacture roadmix, as defined in District Rule 2020, is not required to be stored in this manner. Roadmix manufacturing operations exempt pursuant to District Rule 2020 shall maintain documentation of their compliance with Rule 2020, and shall readily make said documentation available for District inspection upon request. [District Rule 4623]

47. A leak discovered during operator or District inspection shall be repaired within the following timeframes: within 14 calendar days of discovery for gas leaks less than or equal to 10,000 ppmv, within 2 calendar days of discovery for gas leaks greater than 10,000 ppmv, and within 2 calendar days of discovery for liquid leaks. [District Rule 4623]

48. The operator shall perform periodic component leak inspections once each calendar quarter, except for inaccessible components, unsafe to monitor components and floating roof tanks including their deck fittings and components. Internal floating roof tanks shall be inspected once every 60 months. [District Rule 4623]

49. For periodic component leak inspections, all components shall be tested for leaks of total hydrocarbons in units of parts per million volume (ppmv) in accordance with US EPA Reference Method 21. [District Rule 4623]

50. For periodic component leak inspections, inaccessible components and unsafe to monitor components shall be inspected once every 12 months per US EPA Reference Method 21. [District Rule 4623]

51. For periodic component leak inspections, except for inaccessible components, unsafe to monitor components, and floating roof tanks including deck fittings and components, owners or operators shall audio-visually inspect (by hearing and sight) all hatches, pressure-vacuum relief valves, pressure relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours. [District Rule 4623]

52. For periodic component leak inspections, any audio-visual inspection specified that indicates a leak shall be tested using EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance the leak repair timeframes specified within this permit. [District Rule 4623]

53. For periodic component leak inspections, an operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 24 hours, and leaks shall be repaired in accordance the leak repair timeframes specified within this permit. [District Rule 4623]

54. A District inspection does not fulfill the periodic component leak inspection requirements and cannot be used or counted as an inspection required of the operator. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

55. For periodic leak inspections, upon detection of a component with a leak concentration measured above the limits in this permit, the operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of the leak detection measurement and the measured leak concentration. The tag shall remain affixed to the leaking component until it has been successfully repaired or replaced, after which the tag shall be removed. Successful repair shall be confirmed by re-measuring the components using EPA Reference Method 21 to determine that the component is below the minimum leak threshold after repair or replacement. [District Rule 4623]

56. For periodic leak inspections, excluding tanks, components or component parts which incur five repair actions within a rolling 12-month period shall be replaced with a compliant component in working order and must be re-measured using EPA Reference Method 21, to determine that the component is below the minimum leak threshold. A record of the replacement shall be maintained in a log at the facility, and shall be made available upon request to the APCO. [District Rule 4623]

57. For periodic leak inspections, the operator shall attempt to minimize all component leaks to the extent possible immediately after detection, but no later than one hour after detection of the leak in order to stop or reduce leakage to the atmosphere. [District Rule 4623]

58. For periodic leak inspections, if the leak has been minimized but the leak still exceeds the applicable leak standards in this permit, the operator shall comply with at least one of the following as soon as practicable, but no later than the time period for repairing the leak as specified in this permit: 1) Repair or replace the leaking component; or 2) Vent the leaking component to a VOC control system as defined in Section 3.1 of District Rule 4623 (6/15/23); or 3) Remove the leaking component from operation. [District Rule 4623]

59. For periodic leak inspections, the leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in this permit. The start of the repair period shall be the time of the initial leak detection. [District Rule 4623]

60. The owner or operator shall submit a tank inspection plan to the APCO for approval. The plan shall include an inventory of the tanks subject to this rule and a tank inspection schedule. A copy of the operator's tank safety procedures shall be made available to the APCO upon request. The tank inventory shall include tank's identification number, PTO number, maximum tank capacity, dimensions of tank (height and diameter), organic liquid stored, type of primary and secondary seal, type of floating roof (internal or external floating roof), construction date of tank, and location of tank. Any revision to a previously approved tank inspection schedule shall be submitted to the APCO for approval prior to conducting an inspection. [District Rule 4623]

61. For newly constructed, repaired, or rebuilt internal floating roof tanks, the permittee shall visually inspect the internal floating roof, and its appurtenant parts, fittings, etc. and measure the gaps of the primary seal and/or secondary seal prior to filling the tank for newly constructed, repair, or rebuilt internal floating roof tanks. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to filling the tank. [District Rule 4623 and 40 CFR 60.113b(a)(1)]

62. The operator shall visually inspect, through the manholes, roof hatches, or other opening on the fixed roof, the internal floating roof and its appurtenant parts, fittings, etc., and the primary seal and/or secondary seal at least once every 12 months after the tank is initially filled with an organic liquid. There should be no visible organic liquid on the roof, tank walls, or anywhere. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of vapors. Any defects found are violations of this rule. [District Rule 4623 and 40 CFR 60.113b(a)(2)]

63. The permittee shall conduct actual gap measurements of the primary seal and/or secondary seal at least once every 60 months. Other than the gap criteria specified by this permit, no holes, tears, or other openings are allowed that would permit the escape of hydrocarbon vapors. Any defects found shall constitute a violation of this rule. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

64. If any failure (i.e. visible organic liquid on the internal floating roof, tank walls or anywhere, holes or tears in the seal fabric) is detected during 12 month visual inspection, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If the detected failure cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the APCO in the inspection report. Such a request must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible. [40 CFR 60.113b(a)(2)]

65. The permittee shall notify the District in writing at least 30 days prior to conduct the visual inspection of the storage vessel, so the District can arrange an observer. [40 CFR 60.113b(a)(5)]

66. The permittee shall furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specification of 40 CFR Part 60.112b(a)(1) and 40 CFR Part 60.113b(a)(1) within 15 days after the initial startup of the equipment. [40 CFR 60.115b(a)(1)]

67. The permittee shall submit the reports of the floating roof tank inspections to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Rule 4623, Sections 5.2 through 5.5. The inspection report for tanks that that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and made available upon request by the APCO. The inspection report shall contain all necessary information to demonstrate compliance with the provisions of this rule, including the following: 1) Date the storage vessel was emptied, date of inspection and names and titles of company personnel doing the inspection. 2) Tank identification number and Permit to Operate number. 3) Observed condition of each component of the control equipment (seals, internal floating roof, and fittings). 4) Measurements of the gaps between the tank shell and primary and secondary seals. 5) Leak free status of the tank and floating roof deck fittings. Records of the leak-free status shall include the vapor concentration values measured in parts per million by volume (ppmv). 6) Data, supported by calculations, demonstrating compliance with the requirements specified in Sections 5.4 and 5.5.2.4.3 of Rule 4623. 7) Nature of defects and any corrective actions or repairs performed on the tank in order to comply with rule 4623 and the date(s) such actions were taken. [District Rule 4623 and 40 CFR 60.115b(a)]

68. The operator shall visually inspect the internal floating roof, the primary seal and/or secondary seal, gaskets, slotted membrane and/or sleeve seals each time the storage tank is emptied and degassed. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to refilling the tank. [40 CFR 60.113b(a)(4)]

69. The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel, and these records shall be kept for the life of the source. [40 CFR 60.116b(b)]

70. The operator shall keep an accurate record of each organic liquid stored in the tank, including storage temperature, TVP, and monthly throughput. [District Rule 4623]

71. The operator shall maintain an inspection log containing, at a minimum, the following: 1) Total number of components inspected and total number and percentage of leaking components found during inspection; 2) Location, type, name, or description of each leaking component and description of any unit where the leaking component is found, 3) Date of leak detection and method of leak detection, 4) For gas leaks, record the leak concentration in ppmv, and for liquid leaks record the volume, 5) Date of repair, replacement, or removal from operation of leaking components, 6) After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv, 7) Inspector's name, business mailing address, and business telephone number, 8) The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log, 9) Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components including a copy of the gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4623]

72. The permittee shall maintain records of the volatile organic liquid stored, the period of storage, and TVP of that volatile organic liquid during the respective storage period. TVP shall be determined using the data on the reid vapor pressure (highest receipt or highest tank sample results) and actual storage temperature. [District Rule 2201 and 40 CFR 60.116b(c)]

CONDITIONS CONTINUE ON NEXT PAGE

73. The permittee shall maintain the records of the internal floating roof landing activities that are performed pursuant to Rule 4623, Section 5.3.1.3 and 5.4.3. The records shall include information on the TVP, API gravity, and type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. [District Rule 4623]

74. The permittee shall keep daily records and annual records on a rolling 12-month period of the quantity of organic liquid loaded into the tank, in gallons. [District Rule 2201]

75. The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]

76. All records shall be maintained on site for a period of at least five years and shall be made available for District, ARB, and EPA inspection upon request. [District Rules 1070, 2201 and 4623, and 40 CFR 60.116b(a)]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-31-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
153,300 GALLON SLOP STORAGE TANK WITH AN INTERNAL FLOATING ROOF A MECHANICAL-SHOE PRIMARY SEAL AND A WIPER SECONDARY SEAL

CONDITIONS

1. {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]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Only off-specification product (aka Slop) shall be stored in this tank. The true vapor pressure of the Slop shall not exceed 0.5 psia. [District Rules 2201 and 4623, and 40 CFR 60 Subpart Kb]
4. VOC emissions from this tank shall not exceed 0.1 lb in any one day and shall not exceed 26 lb in any rolling 12-month period. [District Rule 2201]
5. The quantity of slop loaded into this tank shall not exceed 153,300 gallons in any one day and shall not exceed 360,255 gallons in any rolling 12-month period. [District Rule 2201]
6. Total combined fugitive VOC emissions from components such as valves, flanges, connectors, pump seals, etc., associated with tanks N-9742-29, '-30, '-31, and '-32, shall not exceed 1.0 lb/day and 375 lb/rolling 12-month period. [District Rule 2201]
7. Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST 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
N-9742-31-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

8. Component leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]

9. Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rules 2201 and 4623]

10. Gaps between the tank shell and the primary seal shall not exceed 1 1/2 inches. [District Rule 4623]

11. The cumulative length of all gaps between the tank shell and the primary seal greater than 1/2 inch shall not exceed 10% of the circumference of the tank. [District Rule 4623]

12. The cumulative length of all primary seal gaps greater than 1/8 inch shall not exceed 30% of the circumference of the tank. [District Rule 4623]

13. No continuous gap in the primary seal greater than 1/8 inch wide shall exceed 10% of the tank circumference. [District Rule 4623]

14. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. [District Rule 4623]

15. The cumulative length all gaps between the tank shell and the secondary seal, greater than 1/8 inch shall not exceed 5% of the tank circumference. [District Rule 4623]

16. The metallic shoe-type seal shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 6 inches above the stored liquid surface. [District Rule 4623]

17. The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell shall be no greater than 3 inches for a length of at least 18 inches in the vertical plane above the liquid. [District Rule 4623]

18. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. [District Rule 4623]

19. The secondary seal shall allow easy insertion of probes of up to 1 1/2 inches in width in order to measure gaps in the primary seal. [District Rule 4623]

20. The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. [District Rule 4623]

21. The internal floating roof shall be floating on the surface of the stored liquid at all times (i.e., off the roof leg supports) except during the initial fill until the roof is lifted off the leg supports and when the tank is completely emptied and subsequently refilled, and for tank interior cleaning, and during tank repair and maintenance activities. When the roof is resting on the leg supports the processes of filling or emptying and refilling shall be continuous and shall be accomplished as rapidly as possible. Whenever the permittee intends to land the roof on its legs, the permittee shall notify the APCO in writing at least five calendar days prior to performing the work. The tank must be in compliance with this rule before it may land the roof on its legs. [District Rules 2020, 2201 and 4623]

22. All openings in the roof used for sampling and gauging, except pressure-vacuum valves which shall be set to within 10% of the maximum allowable working pressure of the roof, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal or lid that shall be in a closed position at all times, with no visible gaps and be gas tight, except when the device or appurtenance is in use. [District Rule 4623]

23. A leak-free condition is defined as a condition without a gas or liquid leak as defined in this permit. [District Rule 4623]

24. Each opening in a non-contact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents shall provide a projection below the liquid surface. [District Rule 4623]

25. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains shall be equipped with a cover, or a lid shall be maintained in a closed position at all times (i.e. no visible gaps) except when the device is in use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted in place except when they are in use. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

26. Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the leg roof supports. [District Rule 4623]

27. Rim vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. [District Rule 4623]

28. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90 percent of the opening. The fabric cover must be impermeable. [District Rule 4623]

29. Each penetration of the internal floating roof that allows for the passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable. [District Rule 4623]

30. All slotted sampling or gauging wells shall provide a projection below the liquid surface. [District Rule 4623]

31. The gap between the pole wiper and the slotted guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed one-eighth inch. [District Rule 4623]

32. The owner or operator shall notify the APCO in writing at least three days prior to performing tank degassing and interior tank cleaning activities. The written notification shall include the following: 1) The PTO number and physical location of the tank being degassed, 2) The date and time that tank degassing and cleaning activities will begin, 3) The degassing method to be used, 4) The method that will be used to clean the tank, including any solvents to be used, and 5) The method to be used to dispose of the removed sludge including methods that will be used to control emissions during transport. [District Rule 4623]

33. The operator shall maintain records of tank cleaning activities for a period of 5 years and present said records to the APCO upon request. [District Rule 4623]

34. The process of tank degassing shall be accomplished by emptying the tank of organic liquid having a TVP of 0.1 psia or greater and minimizing organic vapors in the tank vapor space by one of the following methods: 1) Exhaust VOCs contained in the tank vapor space to an APCO-approved vapor recovery system until the organic vapor concentration is 5,000 ppmv or less, or is 10 percent or less of the lower explosion limit (LEL), whichever is less; or 2) Displace VOCs contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable liquid until 90 percent or more of the maximum operating level of the tank is filled. Suitable liquids are organic liquids having a TVP of less than 0.1 psia, water, clean produced water, or produced water derived from crude oil having a TVP less than 0.5 psia; or 3) Displace VOC contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable gas. Degassing shall continue until the operator has achieved a vapor displacement equivalent to at least 2.3 times the tank capacity. Suitable gases are air, nitrogen, carbon dioxide, or natural gas containing less than 10 percent VOC by weight. [District Rule 4623]

35. During degassing, the operator shall discharge or displace organic vapors contained in the tank vapor space to an APCO-approved vapor recovery system that is leak free and routes vapors to a VOC control device that reduced the inlet VOC emissions by at least 95 percent by weight. [District Rule 4623]

36. To facilitate connection to an external APCO-approved vapor recovery system during degassing, a suitable fitting such as a manway may be temporarily removed for a period of time not to exceed 1 hour. [District Rule 4623]

37. This tank shall be in compliance with the applicable requirements of District Rule 4623 at all times during draining, degassing, and refilling the tank with an organic liquid having a TVP of 0.1 psia or greater. [District Rule 4623]

38. During tank cleaning operations, draining and refilling of this tank shall occur as a continuous process and shall proceed as rapidly as practicable while the roof is not floating on the surface of the stored liquid. [District Rule 4623]

39. Gap seal requirements shall not apply while the roof is resting on its legs, and during the processes of draining, degassing, or refilling the tank. A leak-free condition will not be required if the operator is draining or refilling this tank in a continuous, expeditious manner. [District Rule 4623]

40. After a tank has been degassed pursuant to the requirements of this permit, vapor control requirements are not applicable until an organic liquid having a TVP of 0.1 psia or greater is placed, held, or stored in this tank. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

41. While performing tank cleaning activities, operators may only use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 degrees F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams of VOC per liter or less. [District Rule 4623]
42. Steam cleaning shall only be allowed at locations where wastewater treatment facilities are limited, or during the months of December through March. [District Rule 4623]
43. During sludge removal, the operator shall control emissions from the sludge receiving vessel by operating an APCO-approved vapor control device that reduces emissions of organic vapors by at least 95%. [District Rule 4623]
44. The permittee shall only transport removed sludge in closed, liquid leak-free containers. [District Rule 4623]
45. The permittee shall store removed sludge, until final disposal, in vapor leak-free containers, or in tanks complying with the vapor control requirements of District Rule 4623. Sludge that is to be used to manufacture roadmix, as defined in District Rule 2020, is not required to be stored in this manner. Roadmix manufacturing operations exempt pursuant to District Rule 2020 shall maintain documentation of their compliance with Rule 2020, and shall readily make said documentation available for District inspection upon request. [District Rule 4623]
46. A leak discovered during operator or District inspection shall be repaired within the following timeframes: within 14 calendar days of discovery for gas leaks less than or equal to 10,000 ppmv, within 2 calendar days of discovery for gas leaks greater than 10,000 ppmv, and within 2 calendar days of discovery for liquid leaks. [District Rule 4623]
47. The operator shall perform periodic component leak inspections once each calendar quarter, except for inaccessible components, unsafe to monitor components and floating roof tanks including their deck fittings and components. Internal floating roof tanks shall be inspected once every 60 months. [District Rule 4623]
48. For periodic component leak inspections, all components shall be tested for leaks of total hydrocarbons in units of parts per million volume (ppmv) in accordance with US EPA Reference Method 21. [District Rule 4623]
49. For periodic component leak inspections, inaccessible components and unsafe to monitor components shall be inspected once every 12 months per US EPA Reference Method 21. [District Rule 4623]
50. For periodic component leak inspections, except for inaccessible components, unsafe to monitor components, and floating roof tanks including deck fittings and components, owners or operators shall audio-visually inspect (by hearing and sight) all hatches, pressure-vacuum relief valves, pressure relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours. [District Rule 4623]
51. For periodic component leak inspections, any audio-visual inspection specified that indicates a leak shall be tested using EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance the leak repair timeframes specified within this permit. [District Rule 4623]
52. For periodic component leak inspections, an operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 24 hours, and leaks shall be repaired in accordance the leak repair timeframes specified within this permit. [District Rule 4623]
53. A District inspection does not fulfill the periodic component leak inspection requirements and cannot be used or counted as an inspection required of the operator. [District Rule 4623]
54. For periodic leak inspections, upon detection of a component with a leak concentration measured above the limits in this permit, the operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of the leak detection measurement and the measured leak concentration. The tag shall remain affixed to the leaking component until it has been successfully repaired or replaced, after which the tag shall be removed. Successful repair shall be confirmed by re-measuring the components using EPA Reference Method 21 to determine that the component is below the minimum leak threshold after repair or replacement. [District Rule 4623]
55. For periodic leak inspections, excluding tanks, components or component parts which incur five repair actions within a rolling 12-month period shall be replaced with a compliant component in working order and must be re-measured using EPA Reference Method 21, to determine that the component is below the minimum leak threshold. A record of the replacement shall be maintained in a log at the facility, and shall be made available upon request to the APCO. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

56. For periodic leak inspections, the operator shall attempt to minimize all component leaks to the extent possible immediately after detection, but no later than one hour after detection of the leak in order to stop or reduce leakage to the atmosphere. [District Rule 4623]

57. For periodic leak inspections, if the leak has been minimized but the leak still exceeds the applicable leak standards in this permit, the operator shall comply with at least one of the following as soon as practicable, but no later than the time period for repairing the leak as specified in this permit: 1) Repair or replace the leaking component; or 2) Vent the leaking component to a VOC control system as defined in Section 3.1 of District Rule 4623 (6/15/23); or 3) Remove the leaking component from operation. [District Rule 4623]

58. For periodic leak inspections, the leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in this permit. The start of the repair period shall be the time of the initial leak detection. [District Rule 4623]

59. The owner or operator shall submit a tank inspection plan to the APCO for approval. The plan shall include an inventory of the tanks subject to this rule and a tank inspection schedule. A copy of the operator's tank safety procedures shall be made available to the APCO upon request. The tank inventory shall include tank's identification number, PTO number, maximum tank capacity, dimensions of tank (height and diameter), organic liquid stored, type of primary and secondary seal, type of floating roof (internal or external floating roof), construction date of tank, and location of tank. Any revision to a previously approved tank inspection schedule shall be submitted to the APCO for approval prior to conducting an inspection. [District Rule 4623]

60. For newly constructed, repaired, or rebuilt internal floating roof tanks, the permittee shall visually inspect the internal floating roof, and its appurtenant parts, fittings, etc. and measure the gaps of the primary seal and/or secondary seal prior to filling the tank for newly constructed, repair, or rebuilt internal floating roof tanks. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to filling the tank. [District Rule 4623]

61. The operator shall visually inspect, through the manholes, roof hatches, or other opening on the fixed roof, the internal floating roof and its appurtenant parts, fittings, etc., and the primary seal and/or secondary seal at least once every 12 months after the tank is initially filled with an organic liquid. There should be no visible organic liquid on the roof, tank walls, or anywhere. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of vapors. Any defects found are violations of this rule. [District Rule 4623]

62. The permittee shall conduct actual gap measurements of the primary seal and/or secondary seal at least once every 60 months. Other than the gap criteria specified by this permit, no holes, tears, or other openings are allowed that would permit the escape of hydrocarbon vapors. Any defects found shall constitute a violation of this rule. [District Rule 4623]

63. The permittee shall submit the reports of the floating roof tank inspections to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Rule 4623, Sections 5.2 through 5.5. The inspection report for tanks that that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and made available upon request by the APCO. The inspection report shall contain all necessary information to demonstrate compliance with the provisions of this rule, including the following: 1) Date the storage vessel was emptied, date of inspection and names and titles of company personnel doing the inspection. 2) Tank identification number and Permit to Operate number. 3) Observed condition of each component of the control equipment (seals, internal floating roof, and fittings). 4) Measurements of the gaps between the tank shell and primary and secondary seals. 5) Leak free status of the tank and floating roof deck fittings. Records of the leak-free status shall include the vapor concentration values measured in parts per million by volume (ppmv). 6) Data, supported by calculations, demonstrating compliance with the requirements specified in Sections 5.4 and 5.5.2.4.3 of Rule 4623. 7) Nature of defects and any corrective actions or repairs performed on the tank in order to comply with rule 4623 and the date(s) such actions were taken. [District Rule 4623]

64. The operator shall keep an accurate record of each organic liquid stored in the tank, including storage temperature, TVP, and monthly throughput. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

65. The operator shall maintain an inspection log containing, at a minimum, the following: 1) Total number of components inspected and total number and percentage of leaking components found during inspection; 2) Location, type, name, or description of each leaking component and description of any unit where the leaking component is found, 3) Date of leak detection and method of leak detection, 4) For gas leaks, record the leak concentration in ppmv, and for liquid leaks record the volume, 5) Date of repair, replacement, or removal from operation of leaking components, 6) After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv, 7) Inspector's name, business mailing address, and business telephone number, 8) The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log, 9) Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components including a copy of the gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4623]

66. The permittee shall maintain records of the volatile organic liquid stored, the period of storage, and TVP of that volatile organic liquid during the respective storage period. TVP shall be determined using the data on the reid vapor pressure (highest receipt or highest tank sample results) and actual storage temperature. [District Rule 2201]

67. The permittee shall maintain the records of the internal floating roof landing activities that are performed pursuant to Rule 4623, Section 5.3.1.3 and 5.4.3. The records shall include information on the TVP, API gravity, and type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. [District Rule 4623]

68. The permittee shall keep daily records and annual records on a rolling 12-month period of the quantity of organic liquid loaded into the tank, in gallons. [District Rule 2201]

69. The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]

70. All records shall be maintained on site for a period of at least five years and shall be made available for District, ARB, and EPA inspection upon request. [District Rules 1070, 2201 and 4623]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-9742-32-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: AEMETIS ADVANCED PRODUCTS RIVERBANK INC
MAILING ADDRESS: 20400 STEVENS CREEK BLVD, SUITE 700
CUPERTINO, CA 95014

LOCATION: 5300 CLAUS RD
RIVERBANK, CA 95357

EQUIPMENT DESCRIPTION:
300,300 GALLON SLOP STORAGE TANK WITH AN INTERNAL FLOATING ROOF A MECHANICAL-SHOE PRIMARY SEAL AND A WIPER SECONDARY SEAL

CONDITIONS

1. {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]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Only off-specification product (aka Slop) shall be stored in this tank. The true vapor pressure of the Slop shall not exceed 0.5 psia. [District Rules 2201 and 4623, and 40 CFR 60 Subpart Kb]
4. VOC emissions from this tank shall not exceed 0.1 lb in any one day and shall not exceed 30 lb in any rolling 12-month period. [District Rule 2201]
5. The quantity of slop loaded into this tank shall not exceed 303,000 gallons in any one day and shall not exceed 705,705 gallons in any rolling 12-month period. [District Rule 2201]
6. Total combined fugitive VOC emissions from components such as valves, flanges, connectors, pump seals, etc., associated with tanks N-9742-29, '-30, '-31, and '-32, shall not exceed 1.0 lb/day and 375 lb/rolling 12-month period. [District Rule 2201]
7. Fugitive VOC emissions from components shall be calculated using the component count, using the leak concentration limit for each type of component, and using the equations from EPA Document "Protocol for Equipment Leak Emission Rates (EPA 453/R-95-017, Nov 1995) Table 2-10, "Petroleum Industry Leak Rate Screening Value Correlations". [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST 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
N-9742-32-0 : Sep 26 2023 11:29AM -- HARADERJ : Joint Inspection NOT Required

8. Component leaks shall be defined as any measurement that results in a gas leak concentration using EPA method 21 that exceeds the following: 100 ppmv for valves (in light liquid or gas service); 500 ppmv for pumps and compressor seals; and 100 ppmv for flanges. [District Rule 2201]
9. Component liquid leaks shall be defined as any leak as a dripping rate of more than three drops per minute. [District Rules 2201 and 4623]
10. Gaps between the tank shell and the primary seal shall not exceed 1 1/2 inches. [District Rule 4623]
11. The cumulative length of all gaps between the tank shell and the primary seal greater than 1/2 inch shall not exceed 10% of the circumference of the tank. [District Rule 4623]
12. The cumulative length of all primary seal gaps greater than 1/8 inch shall not exceed 30% of the circumference of the tank. [District Rule 4623]
13. No continuous gap in the primary seal greater than 1/8 inch wide shall exceed 10% of the tank circumference. [District Rule 4623]
14. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. [District Rule 4623]
15. The cumulative length all gaps between the tank shell and the secondary seal, greater than 1/8 inch shall not exceed 5% of the tank circumference. [District Rule 4623]
16. The metallic shoe-type seal shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 6 inches above the stored liquid surface. [District Rule 4623]
17. The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell shall be no greater than 3 inches for a length of at least 18 inches in the vertical plane above the liquid. [District Rule 4623]
18. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. [District Rule 4623]
19. The secondary seal shall allow easy insertion of probes of up to 1 1/2 inches in width in order to measure gaps in the primary seal. [District Rule 4623]
20. The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. [District Rule 4623]
21. The internal floating roof shall be floating on the surface of the stored liquid at all times (i.e., off the roof leg supports) except during the initial fill until the roof is lifted off the leg supports and when the tank is completely emptied and subsequently refilled, and for tank interior cleaning, and during tank repair and maintenance activities. When the roof is resting on the leg supports the processes of filling or emptying and refilling shall be continuous and shall be accomplished as rapidly as possible. Whenever the permittee intends to land the roof on its legs, the permittee shall notify the APCO in writing at least five calendar days prior to performing the work. The tank must be in compliance with this rule before it may land the roof on its legs. [District Rules 2020, 2201 and 4623]
22. All openings in the roof used for sampling and gauging, except pressure-vacuum valves which shall be set to within 10% of the maximum allowable working pressure of the roof, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal or lid that shall be in a closed position at all times, with no visible gaps and be gas tight, except when the device or appurtenance is in use. [District Rule 4623]
23. A leak-free condition is defined as a condition without a gas or liquid leak as defined in this permit. [District Rule 4623]
24. Each opening in a non-contact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents shall provide a projection below the liquid surface. [District Rule 4623]
25. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains shall be equipped with a cover, or a lid shall be maintained in a closed position at all times (i.e. no visible gaps) except when the device is in use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted in place except when they are in use. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

26. Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the leg roof supports. [District Rule 4623]

27. Rim vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. [District Rule 4623]

28. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90 percent of the opening. The fabric cover must be impermeable. [District Rule 4623]

29. Each penetration of the internal floating roof that allows for the passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable. [District Rule 4623]

30. All slotted sampling or gauging wells shall provide a projection below the liquid surface. [District Rule 4623]

31. The gap between the pole wiper and the slotted guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed one-eighth inch. [District Rule 4623]

32. The owner or operator shall notify the APCO in writing at least three days prior to performing tank degassing and interior tank cleaning activities. The written notification shall include the following: 1) The PTO number and physical location of the tank being degassed, 2) The date and time that tank degassing and cleaning activities will begin, 3) The degassing method to be used, 4) The method that will be used to clean the tank, including any solvents to be used, and 5) The method to be used to dispose of the removed sludge including methods that will be used to control emissions during transport. [District Rule 4623]

33. The operator shall maintain records of tank cleaning activities for a period of 5 years and present said records to the APCO upon request. [District Rule 4623]

34. The process of tank degassing shall be accomplished by emptying the tank of organic liquid having a TVP of 0.1 psia or greater and minimizing organic vapors in the tank vapor space by one of the following methods: 1) Exhaust VOCs contained in the tank vapor space to an APCO-approved vapor recovery system until the organic vapor concentration is 5,000 ppmv or less, or is 10 percent or less of the lower explosion limit (LEL), whichever is less; or 2) Displace VOCs contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable liquid until 90 percent or more of the maximum operating level of the tank is filled. Suitable liquids are organic liquids having a TVP of less than 0.1 psia, water, clean produced water, or produced water derived from crude oil having a TVP less than 0.5 psia; or 3) Displace VOC contained in the tank vapor space to an APCO-approved vapor recovery system by filling the tank with a suitable gas. Degassing shall continue until the operator has achieved a vapor displacement equivalent to at least 2.3 times the tank capacity. Suitable gases are air, nitrogen, carbon dioxide, or natural gas containing less than 10 percent VOC by weight. [District Rule 4623]

35. During degassing, the operator shall discharge or displace organic vapors contained in the tank vapor space to an APCO-approved vapor recovery system that is leak free and routes vapors to a VOC control device that reduced the inlet VOC emissions by at least 95 percent by weight. [District Rule 4623]

36. To facilitate connection to an external APCO-approved vapor recovery system during degassing, a suitable fitting such as a manway may be temporarily removed for a period of time not to exceed 1 hour. [District Rule 4623]

37. This tank shall be in compliance with the applicable requirements of District Rule 4623 at all times during draining, degassing, and refilling the tank with an organic liquid having a TVP of 0.1 psia or greater. [District Rule 4623]

38. During tank cleaning operations, draining and refilling of this tank shall occur as a continuous process and shall proceed as rapidly as practicable while the roof is not floating on the surface of the stored liquid. [District Rule 4623]

39. Gap seal requirements shall not apply while the roof is resting on its legs, and during the processes of draining, degassing, or refilling the tank. A leak-free condition will not be required if the operator is draining or refilling this tank in a continuous, expeditious manner. [District Rule 4623]

40. After a tank has been degassed pursuant to the requirements of this permit, vapor control requirements are not applicable until an organic liquid having a TVP of 0.1 psia or greater is placed, held, or stored in this tank. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

41. While performing tank cleaning activities, operators may only use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 degrees F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams of VOC per liter or less. [District Rule 4623]

42. Steam cleaning shall only be allowed at locations where wastewater treatment facilities are limited, or during the months of December through March. [District Rule 4623]

43. During sludge removal, the operator shall control emissions from the sludge receiving vessel by operating an APCO-approved vapor control device that reduces emissions of organic vapors by at least 95%. [District Rule 4623]

44. The permittee shall only transport removed sludge in closed, liquid leak-free containers. [District Rule 4623]

45. The permittee shall store removed sludge, until final disposal, in vapor leak-free containers, or in tanks complying with the vapor control requirements of District Rule 4623. Sludge that is to be used to manufacture roadmix, as defined in District Rule 2020, is not required to be stored in this manner. Roadmix manufacturing operations exempt pursuant to District Rule 2020 shall maintain documentation of their compliance with Rule 2020, and shall readily make said documentation available for District inspection upon request. [District Rule 4623]

46. A leak discovered during operator or District inspection shall be repaired within the following timeframes: within 14 calendar days of discovery for gas leaks less than or equal to 10,000 ppmv, within 2 calendar days of discovery for gas leaks greater than 10,000 ppmv, and within 2 calendar days of discovery for liquid leaks. [District Rule 4623]

47. The operator shall perform periodic component leak inspections once each calendar quarter, except for inaccessible components, unsafe to monitor components and floating roof tanks including their deck fittings and components. Internal floating roof tanks shall be inspected once every 60 months. [District Rule 4623]

48. For periodic component leak inspections, all components shall be tested for leaks of total hydrocarbons in units of parts per million volume (ppmv) in accordance with US EPA Reference Method 21. [District Rule 4623]

49. For periodic component leak inspections, inaccessible components and unsafe to monitor components shall be inspected once every 12 months per US EPA Reference Method 21. [District Rule 4623]

50. For periodic component leak inspections, except for inaccessible components, unsafe to monitor components, and floating roof tanks including deck fittings and components, owners or operators shall audio-visually inspect (by hearing and sight) all hatches, pressure-vacuum relief valves, pressure relief devices, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours. [District Rule 4623]

51. For periodic component leak inspections, any audio-visual inspection specified that indicates a leak shall be tested using EPA Reference Method 21 within 24 hours, and the leak shall be repaired in accordance the leak repair timeframes specified within this permit. [District Rule 4623]

52. For periodic component leak inspections, an operator shall inspect all new, replaced, or repaired fittings, flanges, and threaded connections within 24 hours, and leaks shall be repaired in accordance the leak repair timeframes specified within this permit. [District Rule 4623]

53. A District inspection does not fulfill the periodic component leak inspection requirements and cannot be used or counted as an inspection required of the operator. [District Rule 4623]

54. For periodic leak inspections, upon detection of a component with a leak concentration measured above the limits in this permit, the operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of the leak detection measurement and the measured leak concentration. The tag shall remain affixed to the leaking component until it has been successfully repaired or replaced, after which the tag shall be removed. Successful repair shall be confirmed by re-measuring the components using EPA Reference Method 21 to determine that the component is below the minimum leak threshold after repair or replacement. [District Rule 4623]

55. For periodic leak inspections, excluding tanks, components or component parts which incur five repair actions within a rolling 12-month period shall be replaced with a compliant component in working order and must be re-measured using EPA Reference Method 21, to determine that the component is below the minimum leak threshold. A record of the replacement shall be maintained in a log at the facility, and shall be made available upon request to the APCO. [District Rule 4623]

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CONDITIONS CONTINUE ON NEXT PAGE

56. For periodic leak inspections, the operator shall attempt to minimize all component leaks to the extent possible immediately after detection, but no later than one hour after detection of the leak in order to stop or reduce leakage to the atmosphere. [District Rule 4623]

57. For periodic leak inspections, if the leak has been minimized but the leak still exceeds the applicable leak standards in this permit, the operator shall comply with at least one of the following as soon as practicable, but no later than the time period for repairing the leak as specified in this permit: 1) Repair or replace the leaking component; or 2) Vent the leaking component to a VOC control system as defined in Section 3.1 of District Rule 4623 (6/15/23); or 3) Remove the leaking component from operation. [District Rule 4623]

58. For periodic leak inspections, the leak rate measured after leak minimization has been performed shall be the leak rate used to determine the repair period specified in this permit. The start of the repair period shall be the time of the initial leak detection. [District Rule 4623]

59. The owner or operator shall submit a tank inspection plan to the APCO for approval. The plan shall include an inventory of the tanks subject to this rule and a tank inspection schedule. A copy of the operator's tank safety procedures shall be made available to the APCO upon request. The tank inventory shall include tank's identification number, PTO number, maximum tank capacity, dimensions of tank (height and diameter), organic liquid stored, type of primary and secondary seal, type of floating roof (internal or external floating roof), construction date of tank, and location of tank. Any revision to a previously approved tank inspection schedule shall be submitted to the APCO for approval prior to conducting an inspection. [District Rule 4623]

60. For newly constructed, repaired, or rebuilt internal floating roof tanks, the permittee shall visually inspect the internal floating roof, and its appurtenant parts, fittings, etc. and measure the gaps of the primary seal and/or secondary seal prior to filling the tank for newly constructed, repair, or rebuilt internal floating roof tanks. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to filling the tank. [District Rule 4623]

61. The operator shall visually inspect, through the manholes, roof hatches, or other opening on the fixed roof, the internal floating roof and its appurtenant parts, fittings, etc., and the primary seal and/or secondary seal at least once every 12 months after the tank is initially filled with an organic liquid. There should be no visible organic liquid on the roof, tank walls, or anywhere. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of vapors. Any defects found are violations of this rule. [District Rule 4623]

62. The permittee shall conduct actual gap measurements of the primary seal and/or secondary seal at least once every 60 months. Other than the gap criteria specified by this permit, no holes, tears, or other openings are allowed that would permit the escape of hydrocarbon vapors. Any defects found shall constitute a violation of this rule. [District Rule 4623]

63. The permittee shall submit the reports of the floating roof tank inspections to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Rule 4623, Sections 5.2 through 5.5. The inspection report for tanks that that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and made available upon request by the APCO. The inspection report shall contain all necessary information to demonstrate compliance with the provisions of this rule, including the following: 1) Date the storage vessel was emptied, date of inspection and names and titles of company personnel doing the inspection. 2) Tank identification number and Permit to Operate number. 3) Observed condition of each component of the control equipment (seals, internal floating roof, and fittings). 4) Measurements of the gaps between the tank shell and primary and secondary seals. 5) Leak free status of the tank and floating roof deck fittings. Records of the leak-free status shall include the vapor concentration values measured in parts per million by volume (ppmv). 6) Data, supported by calculations, demonstrating compliance with the requirements specified in Sections 5.4 and 5.5.2.4.3 of Rule 4623. 7) Nature of defects and any corrective actions or repairs performed on the tank in order to comply with rule 4623 and the date(s) such actions were taken. [District Rule 4623]

64. The operator shall keep an accurate record of each organic liquid stored in the tank, including storage temperature, TVP, and monthly throughput. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

65. The operator shall maintain an inspection log containing, at a minimum, the following: 1) Total number of components inspected and total number and percentage of leaking components found during inspection; 2) Location, type, name, or description of each leaking component and description of any unit where the leaking component is found, 3) Date of leak detection and method of leak detection, 4) For gas leaks, record the leak concentration in ppmv, and for liquid leaks record the volume, 5) Date of repair, replacement, or removal from operation of leaking components, 6) After the component is repaired or is replaced, the date of re-inspection and the leak concentration in ppmv, 7) Inspector's name, business mailing address, and business telephone number, 8) The facility operator responsible for the inspection and repair program shall sign and date the inspection log certifying the accuracy of the information recorded in the log, 9) Records of each calibration of the portable hydrocarbon detection instrument utilized for inspecting components including a copy of the gas certification from the vendor of said calibration gas cylinder, the date of calibration, concentration of calibration gas, instrument reading of calibration gas after adjustment, calibration gas expiration date, and calibration gas cylinder pressure at the time of calibration. [District Rule 4623]

66. The permittee shall maintain records of the volatile organic liquid stored, the period of storage, and TVP of that volatile organic liquid during the respective storage period. TVP shall be determined using the data on the reid vapor pressure (highest receipt or highest tank sample results) and actual storage temperature. [District Rule 2201]

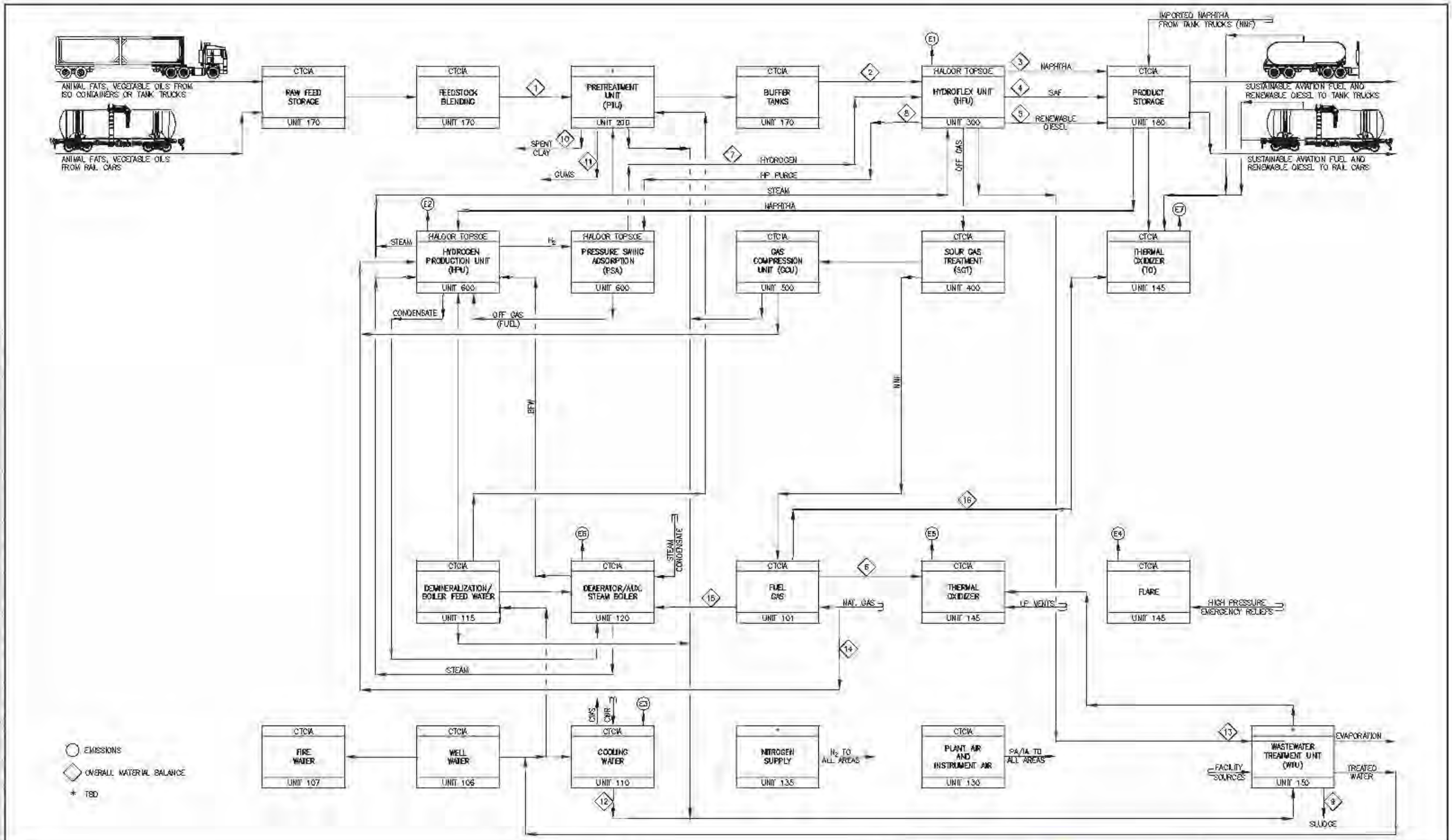
67. The permittee shall maintain the records of the internal floating roof landing activities that are performed pursuant to Rule 4623, Section 5.3.1.3 and 5.4.3. The records shall include information on the TVP, API gravity, and type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. [District Rule 4623]

68. The permittee shall keep daily records and annual records on a rolling 12-month period of the quantity of organic liquid loaded into the tank, in gallons. [District Rule 2201]

69. The permittee shall maintain records sufficient to demonstrate compliance with each emission limit. These records shall contain each calculated emission quantity as well as each process variable used in the respective calculations/modeling. [District Rule 2201]

70. All records shall be maintained on site for a period of at least five years and shall be made available for District, ARB, and EPA inspection upon request. [District Rules 1070, 2201 and 4623]

APPENDIX B
Process Diagram



NOTES:

NO.	DATE	REVISION – DESCRIPTION	BY	CHKD.	APPV.
0	06 SEP 2022	ISSUED FOR USE	LM	AC	JRD

CTCI Americas, Inc.

DWN. BY: LM	DATE: 11/08/2021	DSGN. APPV.:	DATE:
CHK. BY: AC	DATE: 11/10/2021	APPV. BY: JRD	DATE: 12/09/2021
PROJECT NO. 21S4825A	UNIT NO.	SCALE: NTS	

AEMETIS

OVERALL BLOCK FLOW DIAGRAM
CARBON ZERO 1 PROJECT
RIVERBANK, CALIFORNIA

DWG. NO. XC41-0000-0001 SHEET 1/1 REV. NO. 0

APPENDIX C
Engine Data Sheet

CLARKE®

C18H0 MODELS

UFAD12	UFAD20	UFAD58	UFAC18
UFAD18	UFAD38	UFAD50	UFAC10
UFAD22	UFAD42	UFAD68	UFAC28
UFAD10	UFAD30	UFAA78	UFAC20
UFAD32	UFAD48	UFAD78	
UFAD28	UFAD40	UFAD70	

UL/FM - cUL APPROVED RATINGS BHP/kW

C18H0 MODEL ♦	RATED SPEED 1470		1760		1900		2100		EMISSIONS
UFAD12*	**450**	*335*							EPA Tier 3 Certified
UFAD18			**460**	*343*					EPA Tier 3 Certified
UFAD22*	**475**	*354*							EPA Tier 3 Certified
UFAD10					**488**	*364*	**488**	*364*	EPA Tier 3 Certified
UFAD32*	**491**	*366*							EPA Tier 3 Certified
UFAD28			**510**	*380*					EPA Tier 3 Certified
UFAD20					**525**	*392*	**525**	*392*	EPA Tier 3 Certified
UFAD38			**542**	*404*					EPA Tier 3 Certified
UFAD42	**570**	*425*							EPA Tier 3 Certified
UFAD30					**575**	*429*	**575**	*429*	EPA Tier 3 Certified
UFAD48			**600**	*447*					EPA Tier 3 Certified
UFAD40					**600**	*447*	**600**	*447*	EPA Tier 3 Certified
UFAD58			**650**	*485*					EPA Tier 3 Certified
UFAD50					**650**	*485*	**650**	*485*	EPA Tier 3 Certified
UFAD68			**687**	*512*					EPA Tier 3 Certified
UFAA78	**700**	*522*							Non-Emissionized
UFAD78			**700**	*522*					EPA Tier 3 Certified
UFAD70					**700**	*522*	**700**	*522*	EPA Tier 3 Certified
UFAC18			**755**	*563*					EPA Tier 2 Certified
UFAC10					**755**	*563*	**755**	*563*	EPA Tier 2 Certified
UFAC28			**800**	*596.5*					EPA Tier 2 Certified
UFAC20					**800**	*596.5*	**800**	*596.5*	EPA Tier 2 Certified

*Utilizes a single turbo base engine.

♦ All Models are available for export

ENGINE SPECIFICATIONS	
Number of Cylinders	6
Aspiration	TRWA
Rotation*	CW
Overall Dimensions - in. (mm)	66.1(1678) H X 79.6(2022) L X 45.2(1147) W
Crankshaft Centerline Height - in. (mm)	17.0 (432)
Weight - lb (kg)	4100 (1860)
Compression Ratio	16.3:1
Displacement - cu. in. (l)	1104 (18.1)
Engine Type	4 Stroke Cycle - Inline Construction

Abbreviations: TRWA - Turbocharged and Raw Water Aftercooled CW - Clockwise
*Rotation viewed from Heat Exchanger / Front of engine

CERTIFIED POWER RATING

- Each engine is factory tested to verify power and performance

c UL us LISTED NFPA FM APPROVED

ENGINE RATINGS BASELINES

- Engines are to be used for stationary emergency standby fire pump service only. Engines are to be tested in accordance with NFPA 25.
- Engines are rated at standard SAE conditions of 29.61 in. (752.1 mm) 77°F (25°C) inlet air temperature [approximates 300 ft. (91.4 m) above sea level] by the testing laboratory (see SAE Standard J 1349).
- A deduction of 3 percent from engine horsepower rating at standard SAE conditions shall be made for diesel engines for each 1000 ft. (305 m) altitude above 300 ft. (91.4 m)
- A deduction of 1 percent from engine horsepower rating as corrected to standard SAE conditions shall be made for diesel engines for every 10°F (5.6°C) above 77°F (25°C) ambient temperature.

APPENDIX D
Breeze Tanks ESP Results

TankSummaries for 2022 Annual
Site: Aemetis,
Equations for this site: After 2019 AP-42 revisions H/D ratio: Default 0.5

Tank ID	Tank Diameter (ft)	Tank Type	Product	RVP	Throughput (gal)	Bulk Liquid Temperature (degF)	Avg. Liquid Surface Temp. (degF)	Avg. TVP (psia)	Includes a landing loss?	Initial fill?	Includes a tank cleaning?	Number of Days	Estimated standing losses (lbs)	Estimated working losses (lbs)	Routine Emissions (lbs)	Non Routine Emissions (lbs)	Total estimated emissions (lbs)
Naphtha_Tk	33	cone-roof tank with IFR	Gasoline RVP_X	12.5	10568682.18	62.81179	63.64073	7.1172902	N	N	N	365	1360.37	60.40	1420.77	0	1420.77
Slop_Tk_1	33	cone-roof tank with IFR	Jet Fuel		360706.00	62.81179	63.64073	0.1375	N	N	N	365	23.61	2.36	25.96	0	25.96
Slop_Tk_2	42	cone-roof tank with IFR	Jet Fuel		706588.01	62.81179	63.64073	0.1375	N	N	N	365	26.63	3.63	30.25	0	30.25

APPENDIX E.1
BACT Guideline 1.8.5 and Top-Down BACT Analysis for 19.5 MMBtu/hr Process Heater

Back

Best Available Control Technology (BACT) Guideline 1.8.5
Last Update: 3/29/2023

Process heaters with heat input rate =< 20 MMBtu/hr**

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
NOx	9 ppmvd @ 3% O2 (0.011 lb/MMBtu)	5 ppmvd @ 3% O2 (0.0061 lb/MMBtu)	
SOx	PUC quality natural gas or propane with LPG backup		
PM10	PUC quality natural gas or propane with LPG backup		
CO	50 ppmvd @ 3% O2 (0.037 lb/MMBtu)		
VOC	PUC quality natural gas or propane with LPG backup		

***This guideline is applicable to units fired solely on natural gas from a PUC regulated source or propane/LPG. This guideline is not applicable to Refinery Units, Oilfield Steam Generators, or Electric Utility Steam Generating Units.*

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

This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.

Top-Down BACT Analysis

BACT Analysis for NOx Emissions:

a. Step 1 - Identify All Possible Control Technologies

The SJVAPCD BACT Clearinghouse guideline 1.8.5 (Last Updated 03/29/23), identifies achieved in practice and technologically feasible BACT control technologies for NOx from Process heaters =< 20 MMBtu/hr as follows:

1) 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu) - achieved in practice
2) 5 ppmvd @ 3% O_2 (0.0061 lb/MMBtu) – technologically feasible

b. Step 2 - Eliminate Technologically Infeasible Options

None of the above listed control technologies are technologically infeasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 5 ppmvd @ 3% O_2 (0.061 lb/MMBtu) - technologically feasible
2. 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu) - achieved in practice

d. Step 4 - Cost Effectiveness Analysis

The applicant is proposing a process heater with a NOx emission factor of 5 ppmvd @ 3% O_2, which is the most effective control technology identified in Step 3. Since the applicant is proposing the most effective control technology, a cost effective analysis is not required.

e. Step 5 - Select BACT

The applicant is proposing the most effective NOx control technology, therefore, BACT for NOx is satisfied.

APPENDIX E.2
BACT Analysis for 27.6 MMBtu/hr and 41.5 MMBtu/hr Process Heaters

San Joaquin Valley Air Pollution Control District

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

Emission Unit: Natural Gas-Fired Process Heater **Industry Type:** All

Equipment Rating: > 20 MMBtu/hr **Last Update:** TBD

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NOx	5 ppmvd @ 3% O_2	2.5 ppmvd @ 3% O_2	
SOx	Use of PUC-Quality Natural Gas		
PM10	Use of PUC-Quality Natural Gas		

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

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

Best Available Control Technology Analysis

Process Heaters > 20 MMBtu/hr (natural gas-fired)

Prepared by:
James Harader, Supervising Air Quality Engineer

Reviewed by:
Nick Peirce, Permit Services Manager

I. Introduction

The purpose of this analysis is to determine Best Available Control Technology (BACT) requirements for process heaters with a rating > 20 MMBtu/hr. This analysis will be limited to natural gas-fired units. The BACT Guideline for this source category will be developed and published under a separate project.

II. Source of emissions

Aemetis Riverbank is proposing three process heaters in this size range:

1. 27.6 MMBtu/hr Natural Gas-Fired Process Heater
   - Triggers BACT for NOx

2. 41.5 MMBtu/hr Natural Gas-Fired Process Heater
   - Triggers BACT for NOx, SOx, and PM_{10}

These emissions result from the combustion of gaseous fuels in the process heaters.

III. Top-Down BACT Analysis

BACT analysis for NOx Emissions

Step 1 - Identify All Possible NOx Control Technologies

The following BACT clearinghouse references were reviewed to determine the control technologies that have been required for NOx from process heaters.

– EPA RACT/BACT/LAER (RBLC) clearinghouse
– CARB BACT clearinghouse
– South Coast AQMD (SCAQMD) BACT clearinghouse
– Bay Area AQMD (BAAQMD) BACT clearinghouse
– Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
– San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse
– Monterey Bay Air Resources District (MBARD) BACT clearinghouse
– Santa Barbara County APCD (SBAPCD) BACT clearinghouse

The following table shows the results of the search of the EPA RBLC:

Non-Refinery Units from EPA RBLC		
RBLC ID Facility Name	**Fuel** Equipment Rating	**NOx Limit**
LA-0345 Nucor Steel Louisiana	**Natural Gas** 923 MMBtu/hr	0.007 lb/MMBtu
TX-0865 Equistar Chemicals	**Natural Gas and Process Gas** 202 MMBtu/hr	5 ppmvd @ 3% O_2
AR-0162 Energy Security Partners	**Fuel Gas** 391.5 MMBtu/hr	0.03 lb/MMBtu
TX-0933 Nacero Penwell	**Natural Gas and Fuel Gas** Not Provided	0.015 lb/MMBtu
LA-0346 IGP Methanol	**Not Identified** 522 MMBtu/hr	0.017 lb/MMBtu
SC-0182 Fiber Industries	**Not Identified** Not Provided	0.05 lb/MMBtu
LA-0291 Sasol Chemicals Unit #1	**Process Gas** 73.8 MMBtu/hr	0.038 lb/MMBtu
LA-0291 Sasol Chemicals Unit #2	**Process Gas** 424.8 MMBtu/hr	0.01 lb/MMBtu

The CARB BACT Clearinghouse was searched and applicable BACT Guidelines/Determinations were found from SCAQMD and BAAQMD. The requirements of these guidelines are discussed below.

South Coast BACT Requirements	
Category/Determination	**BACT Requirement for NOx**
Process Heater – Non Refinery BACT Guideline for Non-Major Pollution Facilities (page 104 of BACT Guidelines Part D)	Compliance with South Coast Rule 1146

Bay Area AQMD BACT Requirements*	
Category/Determination	**BACT Requirement for NOx**
Heater – Refinery Process ≥ 50 MMBtu/hr	• 5 ppmvd NOx @ 3% O_2 (Achieved in Practice)
Heater – Refinery Process, Natural or Induced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• 25 ppmvd NOx @ 3% O_2 (Achieved in Practice • 10 ppmvd NOx @ 3% O_2 (Technologically Feasible)
Heater – Refinery Process, Forced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• 20 ppmvd NOx @ 3% O_2 (Achieved in Practice • 10 ppmvd NOx @ 3% O_2 (Technologically Feasible)

*Bay Area AQMD only has BACT Guidelines listed for process heaters at Refineries. Although this BACT Guideline is not applicable to refinery units, refinery process heaters operate similarly to non-refinery process heaters. Therefore, the requirements have been included as a reference point for the emission levels that have been achieved in similar units to those being evaluated in this project.

Monterey Bay ARD, Sacramento Metro AQMD, Santa Barbara County APCD, and San Joaquin Valley APCD Clearinghouses do not include Guidelines that would apply to process heaters > 20 MMBtu/hr.

A review of District, State and Federal rules revealed the following requirements:

Rule	Requirements for NOx
SCAQMD Rule 1146 Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	**≥ 20 MMBtu/hr and ≤ 75 MMBtu/hr** 5 ppmvd @ 3% O_2 **> 75 MMBtu/hr** 5 ppmvd @ 3% O_2
BAAQMD Regulation 9 Rule 7 Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	**≥ 20 MMBtu/hr and ≤ 75 MMBtu/hr** 9 ppmvd @ 3% O_2 **> 75 MMBtu/hr** 5 ppmvd @ 3% O_2
SMAQMD Rule 411 NOx from Boilers, Process Heaters, and Steam Generators	**≥ 20 MMBtu/hr** 30 ppmvd @ 3% O_2
SBCAPCD Rule 342 Boilers, Steam Generators, and Process Heaters	**> 20 MMBtu/hr** 7 ppmvd @ 3% O_2

MBARD Rule 441 Boilers, Steam Generators, and Process Heaters	**<u>≥ 20 MMBtu/hr</u>** 9 ppmvd @ 3% O_2
SJVAPCD Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3	**<u>> 20 MMBtu/hr and ≤ 75 MMBtu/hr</u>** 7 ppmvd @ 3% O_2 **<u>> 75 MMBtu/hr</u>** 5 ppmvd @ 3% O_2
SJVAPCD Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters	**<u>> 20 MMBtu/hr and ≤ 75 MMBtu/hr</u>** 2.5 ppmvd @ 3% O_2 or pay Fees Pursuant to Section 5.3 of Rule 4320 **<u>> 75 MMBtu/hr</u>** 2.5 ppmvd @ 3% O_2 or pay Fees Pursuant to Section 5.3 of Rule 4320

A review of District permits for process heaters (non-refinery) equal to or greater than 20 MMBtu/hr revealed the following operations:

Facility Permit	**Permit Limit for NOx**
Valley Milk N-9149-9-2 24.3 MMBtu/hr natural gas-fired process heater	5 ppmvd @ 3% O_2
California Dairies N-9141-5-0 29.48 MMBtu/hr natural gas-fired process heater	5 ppmvd @ 3% O_2
Gill Ranch Storage, LLC C-7830-2-2 29.4 MMBtu/hr natural gas-fired process heater	9 ppmvd @ 3% O_2
Pacific Pipeline System, LLC S-83-7-11 33.75 MMBtu/hr natural gas-fired process heater	7 ppmvd @ 3% O_2
California Resources Elk Hills S-2234-247-4 68 MMBtu/hr natural gas-fired process heater	7 ppmvd @ 3% O_2

The following control options were identified based on the above information:

Option 1: 5 ppmvd NOx @ 3% O_2 for units rated > 20 MMBtu/hr

This control option is based upon South Coast AQMD Rule 1146 Requirements. Additionally, multiple units were identified above, throughout the size range, that are currently limited to and have demonstrated compliance with 5 ppmvd NOx. Therefore, this option is Achieved in Practice.

Option 2: 7 ppmvd NOx @ 3% O_2 for units rated > 20 MMBtu/hr and ≤ 75 MMBtu/hr, and 5 ppmvd NOx @ 3% O_2 for units rated > 75 MMBtu/hr

This control option is based upon the requirements of San Joaquin Valley Air Pollution Control District Rule 4306. This is the minimum level of control required to comply with San Joaquin Valley Air Pollution Control District Rules. These control levels have been met by multiple units; therefore, this option is Achieved in Practice. This option is less stringent than Option1 and will be removed from consideration.

Option 3: 2.5 ppmvd NOx @ 3% O_2 for units rated > 20 MMBtu/hr

This control option is based upon San Joaquin Valley Air Pollution Control District Rule 4320 requirements. No units were identified that are currently limited to or complying with this emission level. Since no units are currently permitted at this limit, this control option is considered to be Technologically Feasible.

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

All of the items listed in step 1 are technologically feasible. Therefore, none can be eliminated.

<u>Step 3 - Rank Remaining Control Technologies by Control effectiveness</u>

Rank	Capture and Control Efficiency	Status
1. 2.5 ppmvd NOx @ 3% O_2 for all units	N/A	Technologically Feasible
2. 5 ppmvd NOx @ 3% O_2 for all units	N/A	Achieved in Practice

Step 4 - Cost Effectiveness Analysis

The applicant is proposing the most stringent control requirement listed above, 2.5 ppmvd NOx @ 3% O_2. Therefore, a cost effective analysis is not required.

Step 5 - Select BACT

The applicant is proposing the most stringent control technology identified for NOx, 2.5 ppmvd @ 3% O_2, for each process heater rated > 20 MMBtu/hr. Therefore, BACT for NOx emissions is satisfied.

BACT analysis for SOx Emissions

Step 1 - Identify All Possible SOx Control Technologies

The following BACT clearinghouse references were reviewed to determine the control technologies that have been required for SOx from process heaters.

- EPA RACT/BACT/LAER (RBLC) clearinghouse
- CARB BACT clearinghouse
- South Coast AQMD (SCAQMD) BACT clearinghouse
- Bay Area AQMD (BAAQMD) BACT clearinghouse
- Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
- San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse
- Monterey Bay Air Resources District (MBARD) BACT clearinghouse
- Santa Barbara County APCD (SBAPCD) BACT clearinghouse

The following table shows the results of the search of the EPA RBLC:

Non-Refinery Units from EPA RBLC		
RBLC ID Facility Name	**Fuel** Equipment Rating	**SOx Limit**
LA-0345 Nucor Steel Louisiana	**Natural Gas** 923 MMBtu/hr	0.002 lb/MMBtu
TX-0865 Equistar Chemicals	**Natural Gas and Process Gas** 202 MMBtu/hr	None
AR-0162 Energy Security Partners	**Fuel Gas** 391.5 MMBtu/hr	0.0006 lb/MMBtu
TX-0933 Nacero Penwell	**Natural Gas and Fuel Gas** Not Provided	None

The CARB BACT Clearinghouse was searched and applicable BACT Guidelines/Determinations were found from SCAQMD and BAAQMD. The requirements of these guidelines are discussed below.

South Coast BACT Requirements	
Category/Determination	**BACT Requirement for SOx**
Process Heater – Non Refinery BACT Guideline for Non-Major Pollution Facilities (page 104 of BACT Guidelines Part D)	Natural Gas

Bay Area AQMD BACT Requirements*	
Category/Determination	**BACT Requirement for SOx**
Heater – Refinery Process ≥ 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel with ≤ 100 ppmv Total Reduced Sulfur (Achieved in Practice) • Natural Gas or Treated Refinery Gas Fuel with ≤ 50 ppmv Hydrogen Sulfide and ≤ 100 ppmv Total Reduced Sulfur (Technologically Feasible)
Heater – Refinery Process, Natural or Induced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel with ≤ 100 ppmv Total Reduced Sulfur (Achieved in Practice) • Natural Gas or Treated Refinery Gas Fuel with ≤ 50 ppmv Hydrogen Sulfide and ≤ 100 ppmv Total Reduced Sulfur (Technologically Feasible)
Heater – Refinery Process, Forced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel with ≤ 100 ppmv Total Reduced Sulfur (Achieved in Practice) • Natural Gas or Treated Refinery Gas Fuel with ≤ 50 ppmv Hydrogen Sulfide and ≤ 100 ppmv Total Reduced Sulfur (Technologically Feasible)

*Bay Area AQMD only has BACT Guidelines listed for process heaters at Refineries. Although this BACT Guideline is not applicable to refinery units, refinery process heaters operate similarly to non-refinery process heaters. Therefore, the requirements have been included as a reference point for the emission levels that have been achieved in similar units to those being evaluated in this project.

Monterey Bay ARD, Sacramento Metro AQMD, Santa Barbara County APCD, and San Joaquin Valley APCD Clearinghouses do not include Guidelines that would apply to process heaters > 20 MMBtu/hr.

A review of District, State and Federal rules revealed the following requirements:

Rule	Requirements for SOx
South Coast Rule 1146 Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	None
BAAQMD Regulation 9 Rule 7 Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	None
SMAQMD Rule 411 NOx from Boilers, Process Heaters, and Steam Generators	None
SBCAPCD Rule 342 Boilers, Steam Generators, and Process Heaters	None
MBARD Rule 441 Boilers, Steam Generators, and Process Heaters	None
SJVAPCD Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3	None
SJVAPCD Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters	• Fire exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or • Limit fuel sulfur content to no more than 5 grains of total sulfur per 100 scf; or • Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight or limits exhaust SO_2 to less than or equal to 9 ppmv @ 3% O_2

A review of District permits for process heaters (non-refinery) equal to or greater than 20 MMBtu/hr revealed the following operations:

Facility Permit	**Permit Limit for SOx**
Valley Milk N-9149-9-2 24.3 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel
California Dairies N-9141-5-0 29.48 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel
Gill Ranch Storage, LLC C-7830-2-2 29.4 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel
Pacific Pipeline System, LLC S-83-7-11 33.75 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel
California Resources Elk Hills S-2234-247-4 68 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel

The following control options were identified based on the above information:

Option 1: Use of PUC-Quality Natural Gas

This control option is based upon the requirements of San Joaquin Valley Air Pollution Control District Rule 4320. These control levels have been met by multiple units; therefore, this option is Achieved in Practice.

Step 2 - Eliminate Technologically Infeasible Options

All of the items listed in step 1 are technologically feasible. Therefore, none can be eliminated.

Step 3 - Rank Remaining Control Technologies by Control effectiveness

Rank	Capture and Control Efficiency	Status
1. Use of PUC-Quality Natural Gas	N/A	Achieved in Practice

Step 4 - Cost Effectiveness Analysis

The only control option listed is Achieved in Practice. Therefore, a cost effective analysis is not required.

Step 5 - Select BACT

The applicant is proposing the only control option listed for SOx, which is the use of PUC-Quality natural gas. Therefore, BACT for SOx emissions is satisfied.

BACT analysis for PM_{10} Emissions

Step 1 - Identify All Possible PM_{10} Control Technologies

The following BACT clearinghouse references were reviewed to determine the control technologies that have been required for PM_{10} from process heaters.

- EPA RACT/BACT/LAER (RBLC) clearinghouse
- CARB BACT clearinghouse
- South Coast AQMD (SCAQMD) BACT clearinghouse
- Bay Area AQMD (BAAQMD) BACT clearinghouse
- Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
- San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse
- Monterey Bay Air Resources District (MBARD) BACT clearinghouse
- Santa Barbara County APCD (SBAPCD) BACT clearinghouse

The following table shows the results of the search of the EPA RBLC:

Non-Refinery Units from EPA RBLC		
RBLC ID Facility Name	**Fuel** Equipment Rating	**PM_{10} Limit**
LA-0345 Nucor Steel Louisiana	**Natural Gas** 923 MMBtu/hr	0.006 lb/MMBtu
TX-0865 Equistar Chemicals	**Natural Gas and Process Gas** 202 MMBtu/hr	0.007 lb/MMBtu
AR-0162 Energy Security Partners	**Fuel Gas** 391.5 MMBtu/hr	0.0039 lb/MMBtu
TX-0933 Nacero Penwell	**Natural Gas and Fuel Gas** Not Provided	0.0075 lb/MMBtu
LA-0346 IGP Methanol	**Not Identified** 522 MMBtu/hr	0.0075 lb/MMBtu
SC-0182 Fiber Industries	**Not Identified** Not Provided	0.0076 lb/MMBtu

The CARB BACT Clearinghouse was searched and applicable BACT Guidelines/Determinations were found from SCAQMD and BAAQMD. The requirements of these guidelines are discussed below.

South Coast AQMD BACT Requirements	
Category/Determination	**BACT Requirement for PM_{10}**
Process Heater – Non Refinery BACT Guideline for Non-Major Pollution Facilities (page 104 of BACT Guidelines Part D)	Natural Gas

Bay Area AQMD BACT Requirements*	
Category/Determination	**BACT Requirement for PM_{10}**
Heater – Refinery Process ≥ 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel
Heater – Refinery Process, Natural or Induced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel
Heater – Refinery Process, Forced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel

*Bay Area AQMD only has BACT Guidelines listed for process heaters at Refineries. Although this BACT Guideline is not applicable to refinery units, refinery process heaters operate similarly to non-refinery process heaters. Therefore, the requirements have been included as a reference point for the emission levels that have been achieved in similar units to those being evaluated in this project.

Monterey Bay ARD, Sacramento Metro AQMD, Santa Barbara County APCD, and San Joaquin Valley APCD Clearinghouses do not include Guidelines that would apply to process heaters > 20 MMBtu/hr.

A review of District, State and Federal rules revealed the following requirements:

Rule	Requirements for PM_{10}
South Coast Rule 1146 Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	None
BAAQMD Regulation 9 Rule 7 Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	None
SMAQMD Rule 411 NOx from Boilers, Process Heaters, and Steam Generators	None
SBCAPCD Rule 342 Boilers, Steam Generators, and Process Heaters	None
MBARD Rule 441 Boilers, Steam Generators, and Process Heaters	None
SJVAPCD Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3	None
SJVAPCD Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters	• Fire exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or • Limit fuel sulfur content to no more than 5 grains of total sulfur per 100 scf; or • Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight or limits exhaust SO_2 to less than or equal to 9 ppmv @ 3% O_2

A review of District permits for process heaters (non-refinery) equal to or greater than 20 MMBtu/hr revealed the following operations:

Facility Permit	**Permit Limit for PM_{10}**
Valley Milk N-9149-9-2 24.3 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel
California Dairies N-9141-5-0 29.48 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel
Gill Ranch Storage, LLC C-7830-2-2 29.4 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel
Pacific Pipeline System, LLC S-83-7-11 33.75 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel
California Resources Elk Hills S-2234-247-4 68 MMBtu/hr natural gas-fired process heater	Use of PUC Natural Gas Fuel

The following control options were identified based on the above information:

Option 1: Use of PUC-Quality Natural Gas

This control option is based upon the requirements of San Joaquin Valley Air Pollution Control District Rule 4320. These control levels have been met by multiple units; therefore, this option is Achieved in Practice.

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

All of the items listed in step 1 are technologically feasible. Therefore, none can be eliminated.

Step 3 - Rank Remaining Control Technologies by Control effectiveness

Rank	Capture and Control Efficiency	Status
1. Use of PUC-Quality Natural Gas	N/A	Achieved in Practice

Step 4 - Cost Effectiveness Analysis

The only control option listed is Achieved in Practice. Therefore, a cost effective analysis is not required.

Step 5 - Select BACT

The applicant is proposing the only control option listed for PM_{10}, which is the use of PUC-Quality natural gas. Therefore, BACT for PM_{10} emissions is satisfied.

APPENDIX E.3

BACT Analysis for Hydrogen Production – Steam Hydrocarbon Reformer: Process Heater

San Joaquin Valley Air Pollution Control District

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

Emission Unit: Hydrogen Production - Steam Hydrocarbon Reformer: Process Heater

Industry Type: Hydrogen Production

Equipment Rating: Up to 60 tons of hydrogen production per day, 184 MMBtu/hr Process Heater

Last Update: TBD

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NOx	Process heater meeting a limit of 2.7 ppmv @ 3% O2	Process Heater meeting 2.5 ppmv @ 3% O_2	1) Hydrogen production via electrolysis 2) Hydrogen production via partial oxidation process ([1]), autothermal reforming or gasification
SOx	Process heater firing on a fuel meeting the District Rule 4320 fuel sulfur requirement of 5 grains S/100 dscf		
PM10	Process heater meeting a limit of 0.0039 lb/MMBtu		

([1]) Partial oxidation includes the Grannus Process™ (2023)

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

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

New BACT ANALYSIS
Hydrogen Production – Steam Hydrocarbon Reformer: Process Heater

Facility Name: Aemetis Advanced Products Riverbank

Engineer: James Harader
Lead Engineer: Nick Peirce

Project #: N-9742, N-1224324

I. PROPOSAL

The proposed hydrogen production plant steam-naphtha reformer includes an 184 MMBtu/hr process heater fired on off-gas from the pressure swing adsorber. The process heater creates the steam uses in the steam-naphtha reformer. This new-BACT analysis will address the hydrogen production plant and the main emission unit associated with the hydrogen production process, the 184 MMBtu/hr process heater.

II. PROCESS DESCRIPTION

<u>Hydrogen Production Background</u>:

Hydrogen is a common raw material for many types of products. It is used in processes like energy storage, thermal heating, industrial processes (e.g., manufacture of polymers, methanol), transportation, electricity production, synthesis of synthetic fuels, upgrading oil, and ammonia/fertilizer production. However, to be of use in the proposed process, it first must be separated into pure H2 in order for it to be used as a building block for the proposed sustainable aviation fuel and renewable diesel products.

<u>Proposed Hydrogen Production Method</u>:

Most hydrogen produced today in the United States is performed via steam-methane reforming, a mature production process in which high-temperature steam (700°C–1,000°C) is used to produce hydrogen from a methane source, such as natural gas. In steam-methane reforming, methane reacts with steam in the presence of a catalyst to produce hydrogen, CO, and a relatively small amount of CO2. This method is endothermic (i.e., heat must be supplied to the process for the reaction to proceed).

In a subsequent process called the “water-gas shift reaction,” the carbon monoxide (CO) and steam are reacted using a catalyst to produce CO2 and more hydrogen. In a final process step called “pressure-swing adsorption” process, the CO2 and other impurities are removed from the gas stream leaving essentially pure hydrogen.

Steam-methane reforming reaction
$CH_4 + H_2O$ (+ heat) → $CO + 3H_2$

Water-gas shift reaction
$CO + H_2O$ → $CO_2 + H_2$ (+ small amount of heat)

Alternatively, other hydrocarbons, such as naphtha, may be used as feedstock rather than methane using a similar steam reforming process. For the proposed hydrogen plant, waste naphtha generated by the proposed HydroFlex fuel production operation will be reformed into hydrogen to be used to hydrogenate the feedstocks such as vegetable oils and animal fats.

Steam-hydrocarbon reforming is an endothermic process, meaning it requires heat to be input into the process. For this type of process, heat is input in the form of steam. The steam for the steam-hydrocarbon reforming reaction is generated by the 184 MMBtu/hr process heater that is fired on off-gas from the pressure swing adsorber. The "off gas" is a mixture of unreacted hydrocarbons (naptha, methane, etc.) from the Hydrogen production operation.

BACT is triggered for NOx, SOx and PM_{10} from the process heater that generates steam for the steam-hydrocarbon reforming process.

III. Top-Down BACT Analysis

BACT analysis for NOx Emissions

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

The following BACT clearinghouse references were reviewed to determine the control technologies that have been required for NOx from hydrogen plant process heaters.

- EPA RACT/BACT/LAER (RBLC) clearinghouse
- CARB BACT clearinghouse
- South Coast AQMD (SCAQMD) BACT clearinghouse
- Bay Area AQMD (BAAQMD) BACT clearinghouse
- Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
- San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse
- Monterey Bay Air Resources District (MBARD) BACT clearinghouse
- Santa Barbara County APCD (SBAPCD) BACT clearinghouse

The following table shows the results of the search of the EPA RBLC:

Hydrogen Production – Process Heaters > 20 MMBtu/hr from EPA RBLC		
RBLC ID Facility Name	**Fuel** Equipment Rating	**NOx Limit**
TX-0865 Equistar Chemicals	**Natural Gas and Process Gas** 202 MMBtu/hr	5 ppmvd @ 3% O_2 (0.006 lb/MMBtu)
AR-0162 Energy Security Partners	**Fuel Gas** 391.5 MMBtu/hr	0.03 lb/MMBtu
TX-0933 Nacero Penwell	**Natural Gas and Fuel Gas** Not Provided	0.015 lb/MMBtu
LA-0346 IGP Methanol	**Not Identified** 522 MMBtu/hr	0.017 lb/MMBtu
SC-0182 Fiber Industries	**Not Identified** Not Provided	0.05 lb/MMBtu
LA-0291 Sasol Chemicals Unit #1	**Process Gas** 73.8 MMBtu/hr	0.038 lb/MMBtu
LA-0291 Sasol Chemicals Unit #2	**Process Gas** 424.8 MMBtu/hr	0.1 lb/MMBtu
AR-0173 Big River Steel LLC	**Process Gas** 75 MMBtu/hr	0.1 lb/MMBtu

The CARB BACT Clearinghouse was searched and applicable BACT Guidelines/Determinations were found from SCAQMD and BAAQMD. The requirements of these guidelines are discussed below.

South Coast BACT Requirements	
Category/Determination	**BACT Requirement for NOx**
Process Heater – Non Refinery BACT Guideline for Non-Major Pollution Facilities (page 104 of BACT Guidelines Part D)	Compliance with South Coast Rule 1146
Application #326118 Hydrogen Reforming Furnace	2.7 ppmv @ 3% O_2 (0.0032 lb/MMBtu)
Application #337979 Hydrogen Reforming Furnace	5 ppmv @ 3% O_2 (0.006 lb/MMBtu)
Application #411357 Hydrogen Reforming Furnace	5 ppmv @ 3% O_2 (0.006 lb/MMBtu)
Application #389926 Hydrogen Reforming Furnace	5 ppmv @ 3% O_2 (0.006 lb/MMBtu)

Bay Area AQMD BACT Requirements*	
Category/Determination	**BACT Requirement for NOx**
Heater – Refinery Process ≥ 50 MMBtu/hr	• 5 ppmvd NOx @ 3% O_2 (Achieved in Practice, 0.006 lb/MMBtu)
Heater – Refinery Process, Natural or Induced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• 25 ppmvd NOx @ 3% O_2 (Achieved in Practice, 0.030 lb/MMbtu) • 10 ppmvd NOx @ 3% O_2 (Technologically Feasible, • 0.012 lb/MMBtu)
Heater – Refinery Process, Forced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• 20 ppmvd NOx @ 3% O_2 (Achieved in Practice, 0.024 lb/MMBtu) • 10 ppmvd NOx @ 3% O_2 (Technologically Feasible, 0.012 lb/MMBtu)

*Bay Area AQMD only has BACT Guidelines listed for process heaters at Refineries. Although this BACT Guideline is not applicable to refinery units, refinery process heaters operate similarly to non-refinery process heaters. Therefore, the requirements have been included as a reference point for the emission levels that have been achieved in similar units to those being evaluated in this project.

Monterey Bay ARD, Sacramento Metro AQMD, Santa Barbara County APCD, and San Joaquin Valley APCD Clearinghouses do not include Guidelines that would apply to process heaters > 20 MMBtu/hr.

A review of District, State and Federal rules revealed the following requirements:

Rule	Requirements for NOx
SCAQMD Rule 1146 Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	**≥ 20 MMBtu/hr and ≤ 75 MMBtu/hr** 5 ppmvd @ 3% O_2 (0.006 lb/MMBtu) **> 75 MMBtu/hr** 5 ppmvd @ 3% O_2 (0.006 lb/MMBtu)
BAAQMD Regulation 9 Rule 7 Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	**≥ 20 MMBtu/hr and ≤ 75 MMBtu/hr** 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu) **> 75 MMBtu/hr** 5 ppmvd @ 3% O_2 (0.006 lb/MMBtu)
SMAQMD Rule 411 NOx from Boilers, Process Heaters, and Steam Generators	**≥ 20 MMBtu/hr** 30 ppmvd @ 3% O_2 (0.036 lb/MMBtu)

SBCAPCD Rule 342 Boilers, Steam Generators, and Process Heaters	**<u>> 20 MMBtu/hr</u>** 7 ppmvd @ 3% O_2 (0.0084 lb/MMBtu)
MBARD Rule 441 Boilers, Steam Generators, and Process Heaters	**<u>≥ 20 MMBtu/hr</u>** 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu)
SJVAPCD Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3	**<u>> 20 MMBtu/hr and ≤ 75 MMBtu/hr</u>** 7 ppmvd @ 3% O_2 (0.0084 lb/MMBtu) **<u>> 75 MMBtu/hr</u>** 5 ppmvd @ 3% O_2 (0.006 lb/MMBtu)
SJVAPCD Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters	**<u>> 20 MMBtu/hr and ≤ 75 MMBtu/hr</u>** 2.5 ppmvd @ 3% O_2 (0.003 lb/MMBtu) or pay Fees Pursuant to Section 5.3 of Rule 4320 **<u>> 75 MMBtu/hr</u>** 2.5 ppmvd @ 3% O_2 (0.003 lb/MMBtu) or pay Fees Pursuant to Section 5.3 of Rule 4320

A review of District permits for process heaters equal to or greater than 20 MMBtu/hr revealed the following operations:

Facility Permit	**Permit Limit for NOx**
Alon Bakersfield Refining S-33-53-22 Two 65 MMBtu/hr process gas-fired heaters, a 34.7 MMBtu/hr process gas-fired heater, a 22.7 MMBtu/hr process gas-fired heater, and a 25 MMBtu/hr process gas-fired heater	30 ppmv @ 3% O_2 (0.036 lb/MMBtu)
Alon Bakersfield Refining S-33-55-23 233 MMBtu/hr process gas-fired heater	5 ppmv @ 3% O_2 (0.006 lb/MMBtu)

The following control options were identified based on the above information:

Option 1: 2.7 ppmv NOx @ 3% O_2 for units rated > 20 MMBtu/hr

South Coast AQMD has permitted a unit with a NOx limit of 2.7 ppmvd @ 3% O_2 (Howe Baker Engineers, Application #326118). Furthermore, the heater was operated using pressure swing adsorber off-gas, similar to the proposed unit. This level of control is therefore considered to be achieved in practice.

Option 2: 5 ppmvd NOx @ 3% O_2 for units rated > 20 MMBtu/hr

This control option is based upon South Coast AQMD Rule 1146 Requirements. Additionally, multiple units were identified above, throughout the size range, that are currently limited to and have demonstrated compliance with 5 ppmvd NOx. However, this option is less stringent than option #1, which is achieved in practice; therefore, this option has been eliminated from consideration.

Option 3: 2.5 ppmvd NOx @ 3% O_2 for units rated > 20 MMBtu/hr

This control option is based upon San Joaquin Valley Air Pollution Control District Rule 4320 requirements. No units were identified that are currently limited to or complying with this emission level.

In addition to the above control options, alternate methods of hydrogen do not require the use of a process heater. These methods are considered to be alternate basic equipment. These options are described below:

Alternate Methods of Producing Hydrogen

- <u>Autothermal Reforming (ATR):</u> This process uses oxygen and CO2 or steam in a reaction with methane, or other hydrocarbons, to form synthetic gas, also known as syngas. The reaction takes place in a single chamber where the methane/hydrocarbon is partially oxidized. The reaction is exothermic (i.e., heat is released) due to the oxidation.

  The key difference between steam reforming and autothermal reforming is that steam reforming uses the reaction of hydrocarbons with water, whereas autothermal reforming uses the reaction of methane with oxygen and CO2 or steam to form synthetic gas. Moreover, steam reforming is an endothermic reaction while autothermal reforming is an exothermic reaction.

The reactions can be described in the following equations, using CO_2:

$$2\ CH_4 + O_2 + CO_2 \rightarrow 3\ H_2 + 3\ CO + H_2O$$

And using steam:

$$4\ CH_4 + O_2 + 2\ H_2O \rightarrow 10\ H_2 + 4\ CO$$

Since this process is exothermic, a process heater is not required. Therefore, combustion emissions are not generated by the autothermal reforming process.

- Partial Oxidation: This method is a type of chemical reaction in which methane and other hydrocarbons in natural gas react with a limited amount of oxygen that is not enough to completely oxidize the hydrocarbons to CO_2 and water. With less than the stoichiometric amount of oxygen available, the reaction products contain primarily hydrogen and CO (and nitrogen, if the reaction is carried out with air rather than pure oxygen), and a relatively small amount of CO_2 and other compounds. In a subsequent water-gas shift reaction, the CO reacts with water to form CO_2 and more hydrogen.

  Partial oxidation is an exothermic process that is typically much faster than steam reforming and requires a smaller reactor vessel. As can be seen in chemical reactions of partial oxidation, this process initially produces less hydrogen per unit of the input fuel than is obtained by steam reforming of the same fuel.

  Partial oxidation of methane reaction

$$CH_4 + \tfrac{1}{2}O_2 \rightarrow CO + 2H_2 \text{ (+ heat)}$$

  Water-gas shift reaction

$$CO + H_2O \rightarrow CO_2 + H_2 \text{ (+ small amount of heat)}$$

  This process is exothermic; therefore, a process heater is not required and combustion emissions are not expected from this process.

- Grannus Process: Another process to be considered is the Grannus Process™, a patented exothermic chemical process that integrates a partial oxidation gas boiler with the water gas shift process to make hydrogen synthetic gas as described in its website at: https://grannusllc.com/technology/ and in SJVAPCD project S-8943/S-1163737.

Although the above-mentioned SJVAPCD project issued only an Authority to Construct permit for the installation of a 7.9 MW (nominal ISO rating) electric power generation system (combined cycle configuration) consisting of a natural gas-fired gas turbine engine with heat recovery steam generator (HRSG), that same project determined that the other ammonia plant equipment did not require permits because the plant's emissions units qualified as Low-Emitting Units. The electric power generation system was to provide electrical power and steam to the proposed anhydrous ammonia manufacturing equipment located at the same site at the South Kern Industrial Center in Kern County. However, it should be noted that the facility was not built and the ATC has expired. As proposed in this project, the turbine listed above provided the power; however, the plant can be operated on standard industrial power supplied by the electrical grid.

The anhydrous ammonia fertilizer manufacturing facility that was proposed in that project would have had a capacity of producing 250 tons of anhydrous ammonia fertilizer per day (or the equivalent of approximately 46 tons of hydrogen per day). This plant would have been the first demonstration plant for the Grannus Process™, a process that makes anhydrous ammonia from pipeline natural gas (methane) and water. A detailed description and process flow diagrams are found in the file for project S-1163737. As proposed, the operation relies on certain streams being sent to a gas turbine's heat recovery steam generator for disposal as is explained in the project evaluation.

The Grannus Process includes additional equipment such as an Air Separation Unit and its storage. This equipment requires a footprint of one-half of an acre.

For this BACT Analysis, the Grannus Process will be included in the Partial Oxidation category, since the Grannus Process uses a nearly identical process to produce hydrogen.

- Gasification: This process produces a synthetic gas by reacting coal, petroleum coke, or biomass with high-temperature steam and oxygen in a pressurized gasifier. The resulting synthetic gas contains hydrogen and CO, which is reacted with steam to separate the hydrogen. Using coal gasification with a water gas shift approach produces a pure hydrogen fuel which can be combusted in gas turbines, in fuel cells, and in other applications.

In current practice, large-scale coal gasification installations are primarily for electricity generation, or for production of chemical feedstocks. The hydrogen obtained from coal gasification can be used for various purposes such as making ammonia, powering a hydrogen economy, or upgrading fossil fuels.

This process requires high-temperature steam, similar to the steam methane reforming process. Therefore, a reduction in combustion emissions is not expected.

- Electrolysis: An electric current splits water into hydrogen and oxygen. If the electricity is produced by renewable sources, such as solar or wind, the resulting hydrogen will be considered renewable as well, and has numerous emissions benefits. Power-to-hydrogen projects are becoming more common, using excess renewable electricity, when available, to make hydrogen through electrolysis.

  This process does not require high temperature steam and uses renewable energy, such as solar or wind, to generate the electricity necessary for the electrolysis process. Therefore, a process heater is not required and combustion emissions are not expected.

Several hydrogen production methods are in development, so their potential use in a large commercial project is still not known. Those methods include the following:

- High-Temperature Water Splitting: High temperatures generated by solar concentrators or nuclear reactors drive chemical reactions that split water to produce hydrogen.

- Photobiological Water Splitting: Microbes, such as green algae, consume water in the presence of sunlight and produce hydrogen as a byproduct.

- Photoelectrochemical Water Splitting: Photoelectrochemical systems produce hydrogen from water using special semiconductors and energy from sunlight.

- Pyrolysis: Pyrolysis of natural gas is an endothermic process that occurs in the absence of oxygen to form hydrogen and a solid carbon product. It is thought to be a good method for production of carbon black, but the potential as a source of hydrogen production with low CO2 emissions is still in the development stages. It is believed that more work is needed to better understand its market applications and limitations for commercial projects.

- Photolytic Processes: These processes use light energy to split water into H2 and O2. These processes are currently in the early stages of development and currently are not viable for large-scale production.

- Renewable Liquid Reforming: Renewable liquid fuels, such as ethanol, are reacted with high-temperature steam to produce hydrogen near the point of end use.

- Fermentation: Biomass is converted into sugar-rich feedstocks that can be fermented to produce hydrogen.

Step 2 - Eliminate Technologically Infeasible Options

In the second step, the technological feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific or emissions unit-specific factors. To exclude a control option, a demonstration of technical infeasibility must be clearly documented and should show, based on physical, chemical, and engineering principles, the technical difficulties would preclude the successful use of the control option for the emissions unit under review.\

High-temperature Water Splitting, Photobiological Water Splitting, Photoelectrochemical Water Splitting, Pyrolysis, Photolytic Processes, Renewable Liquid Reforming, and Fermentation are experimental technologies that are not yet commercialized. Therefore, these technologies will be removed from consideration.

Gasification is a commercial technology; however, it would require coal feedstock to be delivered to the facility and will not displace the proposed feedstock used in the proposed production of the biofuels. Furthermore, gasification also requires high-temperature steam which would be generated from combustion; therefore, gasification isn’t believed to currently reduce criteria pollutant emissions from the proposed levels for the steam-hydrocarbon reforming operation. Therefore, this technology will be removed from consideration.

Step 3 - Rank Remaining Control Technologies by Control effectiveness

Rank	Capture and Control Efficiency	Status
1. Electrolysis	N/A	Alternate Basic Equipment
2. Autothermal Reforming	N/A	Alternate Basic Equipment
3. Partial Oxidation/Grannis Process	N/A	Alternate Basic Equipment
4. 2.5 ppmvd NOx @ 3% O_2	N/A	Technologically Feasible
5. 2.7 ppmvd NOx @ 3% O_2	N/A	Achieved in Practice

Step 4 - Cost Effectiveness Analysis

Cost Analyses for Alternate Basic Equipment Options

Electrolysis, Autothermal Reforming, and Partial Oxidation are considered to be alternate basic equipment, since these are alternative processes for producing hydrogen. District Policy APR 1305, *Best Available Control Technology (BACT)*, provides guidance for determining whether alternate basic equipment or processes are cost effective. The following formula is typically used:

$CE_{alt} = (Cost_{alt} – Cost_{Basic}) / (Emission_{Basic} – Emission_{alt})$

Where,

CE_{alt} = cost effectiveness of alternate basic equipment expressed as dollars per ton of emission reduced.

$Cost_{alt}$ = The equivalent annual capital cost of the alternate basic equipment plus its annual operating cost

$Cost_{Basic}$ = The equivalent annual capital cost of the basic equipment, without BACT, plus its annual operating cost

$Emission_{Basic}$ = the emissions from the proposed basic equipment, without BACT

$Emission_{alt}$ = the emissions from the alternate basic equipment

The CE_{alt} ($/ton) is then compared to the cost effectiveness threshold for the pollutant to determine whether the alternate basic equipment is cost effective.

In cases where multiple pollutants are controlled, a traditional cost effectiveness threshold in $/ton is not typically used. Rather, a multi-pollutant cost effectiveness threshold (MCET) is calculated using the following formula

$$MCET = \sum(\text{ton of emission reduction pollutant}_i) \times (\text{cost effectiveness threshold pollutant}_i),$$

Only pollutants that are triggered for BACT are included in calculations to determine the MCET. This method establishes a $/year cost effectiveness threshold, rather than a $/ton threshold.

While the District's BACT Policy doesn't specifically provide guidance on using the MCET for alternate basic equipment, use of the MCET is the most conservative approach; therefore, the MCET will be used to determine the cost effectiveness threshold, and the annual cost will be determined by subtracting $Cost_{Basic}$ from $Cost_{alt}$.

$Cost_{Basic}$ for Steam-hydrocarbon Reforming

The US Department of Energy National Energy Technology Laboratory publication, *Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies (April 2022)*[9], includes a highly detailed cost analysis for steam-methane reforming. A levelized cost of hydrogen of $1.06 per kilogram of hydrogen was derived from the cost analysis. The levelized cost of hydrogen includes capital costs, maintenance costs, owners' costs, and operating costs. However, the levelized cost of hydrogen assumes that methane is purchased and then processed into hydrogen. The proposed hydrogen plant is nearly 100% fueled from naphtha and hydrocarbon waste gases generated by the proposed HydroFlex plant (N-9742-20-0). Therefore, the cost of methane, $0.77/kilogram of hydrogen, will be deducted from the total levelized cost of hydrogen. Additionally, electricity costs accounted for $0.04507/kilogram of hydrogen produced in the publication; however, that value was based on an electricity cost of $71.70/MWh of electricity used. The latest electricity cost for industrial usage in California is $207.2/MWh of electricity[10]; therefore, the electricity cost/kilogram of hydrogen produced was increased to $0.1302 ($0.04507/Kg H_2 x $207.2/MWh ÷ $71.70/MWh). Thus, the adjusted levelized cost of hydrogen (LCOH) is:

9 https://www.netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf

10 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

$LCOH_{adjusted}$ = \$1.06/Kg H_2 - \$0.77/Kg H_2 + (\$0.1302 – \$0.04507)/Kg H_2
$LCOH_{adjusted}$= \$0.38/Kg H_2

The hydrogen production plant has a rated output of 61,422 Kg H_2/day. Thus, the annualized cost is:

$Cost_{Basic}$ = 61,422 Kg H_2/day x 365 days/year x \$0.38/Kg H_2
$Cost_{\mathbf{Basic}}$= \$8,519,231/year

<u>$Emissions_{Basic}$ for Steam Methane/Organic Reforming</u>

$Emissions_{Basic}$ is the emissions from the proposed equipment, without BACT. Since the alternate basic equipment would potentially displace multiple emission units (process heater, process vents, and fugitive components), all of these emission units will be included in the analysis. However, only pollutants that trigger BACT from these emission units will be included.

The proposed basic equipment includes a process heater that triggers BACT for NOx, SOx, and PM_{10} emissions. The process heaters do not include add-on controls for SOx and PM_{10}; therefore, the proposed emission rates are "without BACT". The proposed NOx emission rate is based on the Rule 4320 emission limit; therefore, that emission rate is also "without BACT".

The plant also includes hydrogen vents that trigger BACT for VOC emissions. The hydrogen vents are controlled by a thermal oxidizer which is a BACT control. Therefore, the emission rate included below is based upon uncontrolled emissions from the hydrogen vents, without BACT controls.

Additionally, the steam reformer emits fugitive emissions that trigger BACT for VOC emissions. The proposed fugitive emission rate are without BACT.

Annual Emissions: Permit Unit N-9742-21					
Pollutant	**Process Heater W/O BACT (lb/year)**	**Process Vent W/O BACT (lb/year)**	**Fugitives (lb/year)**	**Total (lb/year)**	**Total (tons/year)**
NO_X	9,720	0	0	9,720	4.86
SO_X	20,470	0	0	20,470	10.24
PM_{10}	6,125	0	0	6,125	3.06
VOC	0[11]	36,900[12]	3,030	39,930	19.97

[11] The process heater did not trigger BACT for VOC emissions. Therefore, process heater emissions are equal to zero in this analysis.
[12] District BACT Policy states that emission rates considered are prior to applying BACT. Thus, the control efficiency of the thermal oxidizer serving the hydrogen production vents was not considered when determining $Emissions_{Basic}$ for the process vent.

ABE Option 1: Electrolysis Cost Effectiveness

$Cost_{alt}$ for Electrolysis

Pursuant to the DOE NETL website (https://netl.doe.gov/research/carbon-management/energy-systems/gasification/gasifipedia/technologies-hydrogen), the levelized cost of hydrogen from electrolysis ranges from $4.15 to $10.30 per kilogram of hydrogen produced. The $4.15/kg H_2 value will be conservatively used, without any adjustments.

$Cost_{alt}$ = 61,422 Kg H_2/day x 365 days/year x $4.15/Kg H_2
$Cost_{\mathbf{alt}}$= $93,038,975/year

$Emissions_{alt}$ for Electrolysis

$Emissions_{alt}$ = 0 for all pollutants

MCET for Electrolysis

Electrolysis reduces all emissions to zero. Therefore, all emissions from the steam reforming process are reduced by this technology.

MCET = ∑(ton of emission reduction $pollutant_i$) x (cost effectiveness threshold $pollutant_i$),

MCET = 4.86 tons-NOx/year x $35,300/ton +10.24 tons-SOx/year x $20,400/ton + 3.06 tons-PM10 x $12,800/ton + 19.97 tons-VOC x $25,300/ton

MCET = $924,863/year

Cost Effectiveness for Electrolysis

Cost Effectiveness = $Cost_{alt}$ – $Cost_{Basic}$
Cost Effectiveness = $93,038,975/year –$ 8,519,231/year
Cost Effectiveness = $84,519,744/year

Since this value is greater than the MCET of $924,863/year, electrolysis is not cost effective.

ABE Option 2: Autothermal Reforming Cost Effectiveness

$Cost_{alt}$ for Autothermal Reforming

The US Department of Energy National Energy Technology Laboratory publication, *Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies (April 2022)*, includes a highly detailed cost analysis for autothermal reforming. A levelized cost of hydrogen of $1.51 per kilogram of hydrogen was derived from the cost analysis, with no carbon sequestration. The levelized cost of hydrogen includes capital costs, maintenance costs, owners' costs, and operating costs. However, the levelized cost of hydrogen assumes that methane is purchased and then processed into hydrogen. The proposed hydrogen plant is nearly 100% fueled from naphtha and hydrocarbon waste gases generated by the proposed HydroFlex plant. Therefore, the cost of methane, $0.77/kilogram of hydrogen, will be deducted from the total levelized cost of hydrogen. Additionally, electricity costs accounted for $0.2121/kilogram of hydrogen produced in the publication (after excluding 25% of the power that was allocated towards carbon sequestration); however, that value was based on an electricity cost of $71.70/MWh of electricity used. The latest electricity cost for industrial usage is $207.2/MWh of electricity; therefore, the electricity cost/kilogram of hydrogen produced (without carbon sequestration) was increased to $0.6129 ($0.2121/Kg H_2 x $207.2/MWh ÷ $71.70/MWh). Thus, the adjusted levelized cost of hydrogen (LCOH) is:

$LCOH_{adjusted}$ = $1.51/Kg H_2 - $0.77/Kg H_2 + ($0.6129 – $0.2121)/Kg H_2
$LCOH_{adjusted}$= $1.14/Kg H_2

The hydrogen production plant has a rated output of 61,422 Kg H_2/day. Thus, the annualized cost is:

$Cost_{alt}$ = 61,422 Kg H_2/day x 365 days/year x $1.14/Kg H_2
$Cost_{\mathbf{alt}}$= $25,557,694/year

$Emissions_{alt}$ for Autothermal Reforming

Autothermal reforming is expected to eliminate combustion emissions and to significantly reduce process vent emissions; however, fugitive emissions are still expected. Thus, the emissions from the autothermal reforming process are conservatively calculated below using only the fugitive emission rate:

$Emissions_{alt}$ = 3,030 lb-VOC/year x ton/2000 lb = 1.515 tons-VOC/year

MCET for Autothermal Reforming

MCET = ∑(ton of emission reduction $pollutant_i$) x (cost effectiveness threshold $pollutant_i$),

MCET = 4.86 tons-NOx/year x \$35,300/ton +10.24 tons-SOx/year x \$20,400/ton + 3.06 tons-PM10 x \$12,800/ton + (19.97 tons-VOC – 1.515 tons-VOC) x \$25,300/ton

MCET = \$886,534/year

Cost Effectiveness for Autothermal Reforming

Cost Effectiveness = $Cost_{alt}$ – $Cost_{Basic}$
Cost Effectiveness = \$25,557,694/year –\$ 8,519,231/year
Cost Effectiveness = \$17,038,463/year

Since this value is greater than the MCET of \$886,534/year, autothermal reforming is not cost effective.

ABE Option 3: Partial Oxidation/Grannus Process Cost Effectiveness

$Cost_{alt}$ for Partial Oxidation/Grannus Process

The US Department of Energy National Energy Technology Laboratory publication, *Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies (April 2022)*, includes a highly detailed cost analysis for autothermal reforming. While this analysis was performed for autothermal reforming, several components of a partial oxidation process are identical to the components in an autothermal reforming process. Specifically, an air separation unit is needed to produce oxygen for the both processes. In the DOE study, electricity costs accounted for \$0.2121/kilogram of hydrogen produced in the publication (after excluding 25% of the power that was allocated towards carbon sequestration); however, that value was based on an electricity cost of \$71.70/MWh of electricity used. The latest electricity cost for industrial usage is \$207.2/MWh of electricity; therefore, the electricity cost/kilogram of hydrogen produced (without carbon sequestration) was increased to \$0.6129. Thus, the adjusted levelized cost of hydrogen (LCOH) for partial oxidation, using only the cost of electricity for the air separation unit, is:

$LCOH_{adjusted}$ = \$0.6129/Kg H2

The hydrogen production plant has a rated output of 61,422 Kg H_2/day. Thus, the annualized cost is:

$Cost_{alt}$ = 61,422 Kg H_2/day x 365 days/year x \$0.6129/Kg H_2
$Cost_{\mathbf{alt}}$= \$13,740,623/year

$\underline{\text{Emissions}_{alt}\text{ for Partial Oxidation/Grannus Process}}$

Partial Oxidation eliminates combustion and significantly reduces process vent emissions; however, fugitive emissions are still expected. Therefore, only fugitive emissions are included for Emissions_{alt} for partial oxidation.

Emissions_{alt} = 3,030 lb-VOC/year x ton/2000 lb = 1.515 tons-VOC/year

MCET for Partial Oxidation/Grannus Process

MCET = $\sum$(ton of emission reduction pollutant_i) x (cost effectiveness threshold pollutant_i),

MCET = 4.86 tons-NOx/year x $35,300/ton +10.24 tons-SOx/year x $20,400/ton + 3.06 tons-PM10 x $12,800/ton + (19.97 tons-VOC – 1.515 tons-VOC) x $25,300/ton

MCET = $886,534/year

Cost Effectiveness for Partial Oxidation/Grannus Process

Cost Effectiveness = Cost_{alt} – Cost_{Basic}
Cost Effectiveness = $13,740,623/year –$ 8,519,231/year
Cost Effectiveness = $5,221,392year

Since this value is greater than the MCET of $886,534/year, partial oxidation/Grannus Process is not cost effective. Furthermore, this analysis does not include the capital costs and other costs associated with a partial oxidization hydrogen plant, which would only make partial oxidation processes less cost effective. Therefore, the result of this analysis is very conservative.

Cost Analysis for Technologically Feasible Control Options

Option 4: Process Heater Meeting 2.5 ppmv NOx @ 3 % O_2

A cost analysis is not required, since the applicant is proposing this level of control.

Step 5 - Select BACT

As shown above, alternate basic equipment hydrogen production technologies are not cost effective. BACT is a process heater meeting a NOx limit of 2.5 ppmv @ 3% O_2, which the applicant is proposing. Thus, BACT for NOx is satisfied.

BACT analysis for SOx Emissions

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

The following BACT clearinghouse references were reviewed to determine the control technologies that have been required for SOx from hydrogen plant process heaters.

- EPA RACT/BACT/LAER (RBLC) clearinghouse
- CARB BACT clearinghouse
- South Coast AQMD (SCAQMD) BACT clearinghouse
- Bay Area AQMD (BAAQMD) BACT clearinghouse
- Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
- San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse
- Monterey Bay Air Resources District (MBARD) BACT clearinghouse
- Santa Barbara County APCD (SBAPCD) BACT clearinghouse

The following table shows the results of the search of the EPA RBLC for SOx emissions from similar process heaters:

Non-Refinery Units from EPA RBLC		
RBLC ID Facility Name	**Fuel** Equipment Rating	**SOx Limit**
AR-0162 Energy Security Partners	**Fuel Gas** 391.5 MMBtu/hr	0.0006 lb/MMBtu

The CARB BACT Clearinghouse was searched and applicable BACT Guidelines/Determinations were found from SCAQMD and BAAQMD. The requirements of these guidelines are discussed below.

South Coast BACT Requirements	
Category/Determination	**BACT Requirement for SOx**
Process Heater – Non Refinery BACT Guideline for Non-Major Pollution Facilities (page 104 of BACT Guidelines Part D)	Compliance with South Coast Rule 1146

Bay Area AQMD BACT Requirements*	
Category/Determination	**BACT Requirement for SOx**
Heater – Refinery Process ≥ 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel with ≤ 100 ppmv Total Reduced Sulfur (Achieved in Practice) • Natural Gas or Treated Refinery Gas Fuel with ≤ 50 ppmv Hydrogen Sulfide and ≤ 100 ppmv Total Reduced Sulfur (Technologically Feasible)
Heater – Refinery Process, Natural or Induced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel with ≤ 100 ppmv Total Reduced Sulfur (Achieved in Practice) • Natural Gas or Treated Refinery Gas Fuel with ≤ 50 ppmv Hydrogen Sulfide and ≤ 100 ppmv Total Reduced Sulfur (Technologically Feasible)
Heater – Refinery Process, Forced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel with ≤ 100 ppmv Total Reduced Sulfur (Achieved in Practice) • Natural Gas or Treated Refinery Gas Fuel with ≤ 50 ppmv Hydrogen Sulfide and ≤ 100 ppmv Total Reduced Sulfur (Technologically Feasible)

*Bay Area AQMD only has BACT Guidelines listed for process heaters at Refineries. Although this BACT Guideline is not applicable to refinery units, refinery process heaters operate similarly to non-refinery process heaters. Therefore, the requirements have been included as a reference point for the emission levels that have been achieved in similar units to those being evaluated in this project.

Monterey Bay ARD, Sacramento Metro AQMD, Santa Barbara County APCD, and San Joaquin Valley APCD Clearinghouses do not include Guidelines that would apply to process heaters > 20 MMBtu/hr.

A review of District, State and Federal rules revealed the following requirements:

Rule	Requirements for SOx
South Coast Rule 1146 Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	None
BAAQMD Regulation 9 Rule 7 Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	None
SMAQMD Rule 411 NOx from Boilers, Process Heaters, and Steam Generators	None
SBCAPCD Rule 342 Boilers, Steam Generators, and Process Heaters	None
MBARD Rule 441 Boilers, Steam Generators, and Process Heaters	None
SJVAPCD Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3	None
SJVAPCD Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters	• Fire exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or • Limit fuel sulfur content to no more than 5 grains of total sulfur per 100 scf; or • Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight or limits exhaust SO_2 to less than or equal to 9 ppmv @ 3% O_2

A review of District permits for hydrogen process heaters equal to or greater than 20 MMBtu/hr revealed the following operations:

Facility Permit	**Permit Limit for SOx**
Alon Bakersfield Refining S-33-53-22 Two 65 MMBtu/hr process gas-fired heaters, a 34.7 MMBtu/hr process gas-fired heater, a 22.7 MMBtu/hr process gas-fired heater, and a 25 MMBtu/hr process gas-fired heater	0.0286 lb/MMBtu
Alon Bakersfield Refining S-33-55-23 233 MMBtu/hr process gas-fired heater	0.0286 lb/MMBtu

The following control options were identified based on the above information:

Option 1: Fuel Sulfur Content Meeting District Rule 4320 Requirements

District Rule 4320 requires operations to meet a fuel sulfur content of 5 grains of total Sulfur per 100 scf of gas. This level is achieved in practice. Furthermore, this level of control is expected to be more stringent than a permit limit of 0.0286 lb-SOx/MMBtu or a fuel sulfur content permit limit of 100 ppm (as H_2S).

Alternate Methods of Producing Hydrogen

- Autothermal Reforming (ATR): This process uses oxygen and CO2 or steam in a reaction with methane, or other hydrocarbons, to form synthetic gas, also known as syngas. The reaction takes place in a single chamber where the methane/hydrocarbon is partially oxidized. The reaction is exothermic (i.e., heat is released) due to the oxidation.

  The key difference between steam reforming and autothermal reforming is that steam reforming uses the reaction of hydrocarbons with water, whereas autothermal reforming uses the reaction of methane with oxygen and CO2 or steam to form synthetic gas. Moreover, steam reforming is an endothermic reaction while autothermal reforming is an exothermic reaction.

The reactions can be described in the following equations, using CO_2:

$$2\,CH_4 + O_2 + CO_2 \rightarrow 3\,H_2 + 3\,CO + H_2O$$

And using steam:

$$4\,CH_4 + O_2 + 2\,H_2O \rightarrow 10\,H_2 + 4\,CO$$

Since this process is exothermic, a process heater is not required. Therefore, combustion emissions are not generated by the autothermal reforming process.

- Partial Oxidation: This method is a type of chemical reaction in which methane and other hydrocarbons in natural gas react with a limited amount of oxygen that is not enough to completely oxidize the hydrocarbons to CO_2 and water. With less than the stoichiometric amount of oxygen available, the reaction products contain primarily hydrogen and CO (and nitrogen, if the reaction is carried out with air rather than pure oxygen), and a relatively small amount of CO_2 and other compounds. In a subsequent water-gas shift reaction, the CO reacts with water to form CO_2 and more hydrogen.

  Partial oxidation is an exothermic process that is typically much faster than steam reforming and requires a smaller reactor vessel. As can be seen in chemical reactions of partial oxidation, this process initially produces less hydrogen per unit of the input fuel than is obtained by steam reforming of the same fuel.

  Partial oxidation of methane reaction

$$CH_4 + \tfrac{1}{2}O_2 \rightarrow CO + 2H_2 \text{ (+ heat)}$$

  Water-gas shift reaction

$$CO + H_2O \rightarrow CO_2 + H_2 \text{ (+ small amount of heat)}$$

  This process is exothermic; therefore, a process heater is not required and combustion emissions are not expected from this process.

- Grannus Process: Another process to be considered is the Grannus Process™, a patented exothermic chemical process that integrates a partial oxidation gas boiler with the water gas shift process to make hydrogen synthetic gas as described in its website at: https://grannusllc.com/technology/ and in SJVAPCD project S-8943/S-1163737.

Although the above-mentioned SJVAPCD project issued only an Authority to Construct permit for the installation of a 7.9 MW (nominal ISO rating) electric power generation system (combined cycle configuration) consisting of a natural gas-fired gas turbine engine with heat recovery steam generator (HRSG), that same project determined that the other ammonia plant equipment did not require permits because the plant's emissions units qualified as Low-Emitting Units. The electric power generation system was to provide electrical power and steam to the proposed anhydrous ammonia manufacturing equipment located at the same site at the South Kern Industrial Center in Kern County. However, it should be noted that the facility was not built and the ATC has expired. As proposed in this project, the turbine listed above provided the power; however, the plant can be operated on standard industrial power supplied by the electrical grid.

The anhydrous ammonia fertilizer manufacturing facility that was proposed in that project would have had a capacity of producing 250 tons of anhydrous ammonia fertilizer per day (or the equivalent of approximately 46 tons of hydrogen per day). This plant would have been the first demonstration plant for the Grannus Process™, a process that makes anhydrous ammonia from pipeline natural gas (methane) and water. A detailed description and process flow diagrams are found in the file for project S-1163737. As proposed, the operation relies on certain streams being sent to a gas turbine's heat recovery steam generator for disposal as is explained in the project evaluation.

The Grannus Process includes additional equipment such as an Air Separation Unit and its storage. This equipment requires a footprint of one-half of an acre.

For this BACT Analysis, the Grannus Process will be included in the Partial Oxidation category, since the Grannus Process uses a nearly identical process to produce hydrogen.

- Gasification: This process produces a synthetic gas by reacting coal, petroleum coke, or biomass with high-temperature steam and oxygen in a pressurized gasifier. The resulting synthetic gas contains hydrogen and CO, which is reacted with steam to separate the hydrogen. Using coal gasification with a water gas shift approach produces a pure hydrogen fuel which can be combusted in gas turbines, in fuel cells, and in other applications.

  In current practice, large-scale coal gasification installations are primarily for electricity generation, or for production of chemical feedstocks. The hydrogen obtained from coal gasification can be used for various purposes such as making ammonia, powering a hydrogen economy, or upgrading fossil fuels.

This process requires high-temperature steam, similar to the steam methane reforming process. Therefore, a reduction in combustion emissions is not expected.

- Electrolysis: An electric current splits water into hydrogen and oxygen. If the electricity is produced by renewable sources, such as solar or wind, the resulting hydrogen will be considered renewable as well, and has numerous emissions benefits. Power-to-hydrogen projects are becoming more common, using excess renewable electricity, when available, to make hydrogen through electrolysis.

  This process does not require high temperature steam and uses renewable energy, such as solar or wind, to generate the electricity necessary for the electrolysis process. Therefore, a process heater is not required and combustion emissions are not expected.

Several hydrogen production methods are in development, so their potential use in a large commercial project is still not known. Those methods include the following:

- High-Temperature Water Splitting: High temperatures generated by solar concentrators or nuclear reactors drive chemical reactions that split water to produce hydrogen.

- Photobiological Water Splitting: Microbes, such as green algae, consume water in the presence of sunlight and produce hydrogen as a byproduct.

- Photoelectrochemical Water Splitting: Photoelectrochemical systems produce hydrogen from water using special semiconductors and energy from sunlight.

- Pyrolysis: Pyrolysis of natural gas is an endothermic process that occurs in the absence of oxygen to form hydrogen and a solid carbon product. It is thought to be a good method for production of carbon black, but the potential as a source of hydrogen production with low CO2 emissions is still in the development stages. It is believed that more work is needed to better understand its market applications and limitations for commercial projects.

- Photolytic Processes: These processes use light energy to split water into H2 and O2. These processes are currently in the early stages of development and currently are not viable for large-scale production.

- Renewable Liquid Reforming: Renewable liquid fuels, such as ethanol, are reacted with high-temperature steam to produce hydrogen near the point of end use.

- Fermentation: Biomass is converted into sugar-rich feedstocks that can be fermented to produce hydrogen.

Step 2 - Eliminate Technologically Infeasible Options

In the second step, the technological feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific or emissions unit-specific factors. To exclude a control option, a demonstration of technical infeasibility must be clearly documented and should show, based on physical, chemical, and engineering principles, the technical difficulties would preclude the successful use of the control option for the emissions unit under review.\

High-temperature Water Splitting, Photobiological Water Splitting, Photoelectrochemical Water Splitting, Pyrolysis, Photolytic Processes, Renewable Liquid Reforming, and Fermentation are experimental technologies that are not yet commercialized. Therefore, these technologies will be removed from consideration.

Gasification is a commercial technology; however, it would require coal feedstock to be delivered to the facility and will not displace any feedstock necessary for the production of the biofuels. Furthermore, gasification also requires high-temperature steam which would be generated from combustion; therefore, gasification isn't believed to currently reduce criteria pollutant emissions from the proposed levels for the steam-hydrocarbon reforming operation. Therefore, this technology will be removed from consideration.

Step 3 - Rank Remaining Control Technologies by Control effectiveness

Rank	Capture and Control Efficiency	Status
1. Electrolysis	N/A	Alternate Basic Equipment
2. Autothermal Reforming	N/A	Alternate Basic Equipment
3. Partial Oxidation/Grannus Process	N/A	Alternate Basic Equipment
4. Meet District Rule 4320 Fuel Sulfur Content Requirements	N/A	Achieved in Practice

Step 4 - Cost Effectiveness Analysis

Cost Analyses for Alternate Basic Equipment Options

The cost analysis for ABE options was conducted in the NOx portion of this analysis. The ABE options were determined to not be cost effective.

Step 5 - Select BACT

As shown above, alternate basic equipment hydrogen production technologies are not cost effective. BACT for SOx from the process heater is meeting District Rule 4320 fuel sulfur content requirements.

BACT analysis for PM_{10} Emissions

<u>Step 1 - Identify All Possible PM_{10} Control Technologies</u>

The following BACT clearinghouse references were reviewed to determine the control technologies that have been required for PM_{10} from hydrogen plant process heaters.

- EPA RACT/BACT/LAER (RBLC) clearinghouse
- CARB BACT clearinghouse
- South Coast AQMD (SCAQMD) BACT clearinghouse
- Bay Area AQMD (BAAQMD) BACT clearinghouse
- Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
- San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse
- Monterey Bay Air Resources District (MBARD) BACT clearinghouse
- Santa Barbara County APCD (SBAPCD) BACT clearinghouse

The following table shows the results of the search of the EPA RBLC:

Non-Refinery Units from EPA RBLC		
RBLC ID Facility Name	**Fuel** Equipment Rating	**PM_{10} Limit**
AR-0162 Energy Security Partners	**Fuel Gas** 391.5 MMBtu/hr	0.0039 lb/MMBtu
TX-0933 Nacero Penwell	**Natural Gas and Fuel Gas** Not Provided	0.0075 lb/MMBtu
LA-0346 IGP Methanol	**Not Identified** 522 MMBtu/hr	0.0075 lb/MMBtu
SC-0182 Fiber Industries	**Not Identified** Not Provided	0.0076 lb/MMBtu

The CARB BACT Clearinghouse was searched and applicable BACT Guidelines/Determinations were found from SCAQMD and BAAQMD. The requirements of these guidelines are discussed below.

South Coast AQMD BACT Requirements	
Category/Determination	**BACT Requirement for PM_{10}**
Process Heater – Non Refinery BACT Guideline for Non-Major Pollution Facilities (page 104 of BACT Guidelines Part D)	Natural Gas

Bay Area AQMD BACT Requirements*	
Category/Determination	**BACT Requirement for PM_{10}**
Heater – Refinery Process ≥ 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel
Heater – Refinery Process, Natural or Induced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel
Heater – Refinery Process, Forced Draft 5 MMBtu/hr to < 50 MMBtu/hr	• Natural Gas or Treated Refinery Gas Fuel

*Bay Area AQMD only has BACT Guidelines listed for process heaters at Refineries. Although this BACT Guideline is not applicable to refinery units, refinery process heaters operate similarly to non-refinery process heaters. Therefore, the requirements have been included as a reference point for the emission levels that have been achieved in similar units to those being evaluated in this project.

Monterey Bay ARD, Sacramento Metro AQMD, Santa Barbara County APCD, and San Joaquin Valley APCD Clearinghouses do not include Guidelines that would apply to process heaters > 20 MMBtu/hr.

A review of District, State and Federal rules revealed the following requirements:

Rule	Requirements for PM_{10}
South Coast Rule 1146 Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	None
BAAQMD Regulation 9 Rule 7 Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	None
SMAQMD Rule 411 NOx from Boilers, Process Heaters, and Steam Generators	None
SBCAPCD Rule 342 Boilers, Steam Generators, and Process Heaters	None
MBARD Rule 441 Boilers, Steam Generators, and Process Heaters	None
SJVAPCD Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3	None
SJVAPCD Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters	• Fire exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or • Limit fuel sulfur content to no more than 5 grains of total sulfur per 100 scf; or • Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight or limits exhaust SO_2 to less than or equal to 9 ppmv @ 3% O_2

A review of District permits for process heaters (non-refinery) equal to or greater than 20 MMBtu/hr revealed the following operations:

Facility Permit	**Permit Limit for SOx**
Alon Bakersfield Refining S-33-53-22 Two 65 MMBtu/hr process gas-fired heaters, a 34.7 MMBtu/hr process gas-fired heater, a 22.7 MMBtu/hr process gas-fired heater, and a 25 MMBtu/hr process gas-fired heater	0.0076 lb/MMBtu
Alon Bakersfield Refining S-33-55-23 233 MMBtu/hr process gas-fired heater	0.003 lb/MMBtu*

*While this unit is permitted at 0.003 lb/MMBtu, no source testing was required for this permit unit. Therefore, this limit cannot be verified and will not be considered in establishing BACT for PM_{10}.

The following control options were identified based on the above information:

Option 1: 0.0039 lb-PM_{10}/MMBtu

This level of control has been achieved at Energy Security Partners, listed in the EPA RBLC. Therefore, this level of control is Achieved in Practice.

Option 2: 0.0076 lb-PM_{10}/MMBtu

This is the default AP-42 emission factor for natural gas. However, a lower level of control has been achieved; therefore, this option will be removed from consideration.

Alternate Methods of Producing Hydrogen

- <u>Autothermal Reforming (ATR):</u> This process uses oxygen and CO2 or steam in a reaction with methane, or other hydrocarbons, to form synthetic gas, also known as syngas. The reaction takes place in a single chamber where the methane/hydrocarbon is partially oxidized. The reaction is exothermic (i.e., heat is released) due to the oxidation.

The key difference between steam reforming and autothermal reforming is that steam reforming uses the reaction of hydrocarbons with water, whereas autothermal reforming uses the reaction of methane with oxygen and CO_2 or steam to form synthetic gas. Moreover, steam reforming is an endothermic reaction while autothermal reforming is an exothermic reaction.

The reactions can be described in the following equations, using CO_2:

$$2\ CH_4 + O_2 + CO_2 \rightarrow 3\ H_2 + 3\ CO + H_2O$$

And using steam:

$$4\ CH_4 + O_2 + 2\ H_2O \rightarrow 10\ H_2 + 4\ CO$$

Since this process is exothermic, a process heater is not required. Therefore, combustion emissions are not generated by the autothermal reforming process.

- Partial Oxidation: This method is a type of chemical reaction in which methane and other hydrocarbons in natural gas react with a limited amount of oxygen that is not enough to completely oxidize the hydrocarbons to CO_2 and water. With less than the stoichiometric amount of oxygen available, the reaction products contain primarily hydrogen and CO (and nitrogen, if the reaction is carried out with air rather than pure oxygen), and a relatively small amount of CO_2 and other compounds. In a subsequent water-gas shift reaction, the CO reacts with water to form CO_2 and more hydrogen.

Partial oxidation is an exothermic process that is typically much faster than steam reforming and requires a smaller reactor vessel. As can be seen in chemical reactions of partial oxidation, this process initially produces less hydrogen per unit of the input fuel than is obtained by steam reforming of the same fuel.

Partial oxidation of methane reaction

$$CH_4 + \tfrac{1}{2}O_2 \rightarrow CO + 2H_2\ (\text{+ heat})$$

Water-gas shift reaction

$$CO + H_2O \rightarrow CO_2 + H_2\ (\text{+ small amount of heat})$$

This process is exothermic; therefore, a process heater is not required and combustion emissions are not expected from this process.

- Grannus Process: Another process to be considered is the Grannus Process™, a patented exothermic chemical process that integrates a partial oxidation gas boiler with the water gas shift process to make hydrogen synthetic gas as described in its website at: https://grannusllc.com/technology/ and in SJVAPCD project S-8943/S-1163737.

  Although the above-mentioned SJVAPCD project issued only an Authority to Construct permit for the installation of a 7.9 MW (nominal ISO rating) electric power generation system (combined cycle configuration) consisting of a natural gas-fired gas turbine engine with heat recovery steam generator (HRSG), that same project determined that the other ammonia plant equipment did not require permits because the plant's emissions units qualified as Low-Emitting Units. The electric power generation system was to provide electrical power and steam to the proposed anhydrous ammonia manufacturing equipment located at the same site at the South Kern Industrial Center in Kern County. However, it should be noted that the facility was not built and the ATC has expired. As proposed in this project, the turbine listed above provided the power; however, the plant can be operated on standard industrial power supplied by the electrical grid.

  The anhydrous ammonia fertilizer manufacturing facility that was proposed in that project would have had a capacity of producing 250 tons of anhydrous ammonia fertilizer per day (or the equivalent of approximately 46 tons of hydrogen per day). This plant would have been the first demonstration plant for the Grannus Process™, a process that makes anhydrous ammonia from pipeline natural gas (methane) and water. A detailed description and process flow diagrams are found in the file for project S-1163737. As proposed, the operation relies on certain streams being sent to a gas turbine's heat recovery steam generator for disposal as is explained in the project evaluation.

  The Grannus Process includes additional equipment such as an Air Separation Unit and its storage. This equipment requires a footprint of one-half of an acre.

  For this BACT Analysis, the Grannus Process will be included in the Partial Oxidation category, since the Grannus Process uses a nearly identical process to produce hydrogen.

- Gasification: This process produces a synthetic gas by reacting coal, petroleum coke, or biomass with high-temperature steam and oxygen in a pressurized gasifier. The resulting synthetic gas contains hydrogen and CO, which is reacted with steam to separate the hydrogen. Using coal gasification with a water gas shift approach produces a pure hydrogen fuel which can be combusted in gas turbines, in fuel cells, and in other applications.

In current practice, large-scale coal gasification installations are primarily for electricity generation, or for production of chemical feedstocks. The hydrogen obtained from coal gasification can be used for various purposes such as making ammonia, powering a hydrogen economy, or upgrading fossil fuels.

This process requires high-temperature steam, similar to the steam methane reforming process. Therefore, a reduction in combustion emissions is not expected.

- Electrolysis: An electric current splits water into hydrogen and oxygen. If the electricity is produced by renewable sources, such as solar or wind, the resulting hydrogen will be considered renewable as well, and has numerous emissions benefits. Power-to-hydrogen projects are becoming more common, using excess renewable electricity, when available, to make hydrogen through electrolysis.

  This process does not require high temperature steam and uses renewable energy, such as solar or wind, to generate the electricity necessary for the electrolysis process. Therefore, a process heater is not required and combustion emissions are not expected.

Several hydrogen production methods are in development, so their potential use in a large commercial project is still not known. Those methods include the following:

- High-Temperature Water Splitting: High temperatures generated by solar concentrators or nuclear reactors drive chemical reactions that split water to produce hydrogen.

- Photobiological Water Splitting: Microbes, such as green algae, consume water in the presence of sunlight and produce hydrogen as a byproduct.

- Photoelectrochemical Water Splitting: Photoelectrochemical systems produce hydrogen from water using special semiconductors and energy from sunlight.

- Pyrolysis: Pyrolysis of natural gas is an endothermic process that occurs in the absence of oxygen to form hydrogen and a solid carbon product. It is thought to be a good method for production of carbon black, but the potential as a source of hydrogen production with low CO2 emissions is still in the development stages. It is believed that more work is needed to better understand its market applications and limitations for commercial projects.

- Photolytic Processes: These processes use light energy to split water into H2 and O2. These processes are currently in the early stages of development and currently are not viable for large-scale production.

- Renewable Liquid Reforming: Renewable liquid fuels, such as ethanol, are reacted with high-temperature steam to produce hydrogen near the point of end use.

- Fermentation: Biomass is converted into sugar-rich feedstocks that can be fermented to produce hydrogen.

Step 2 - Eliminate Technologically Infeasible Options

In the second step, the technological feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific or emissions unit-specific factors. To exclude a control option, a demonstration of technical infeasibility must be clearly documented and should show, based on physical, chemical, and engineering principles, the technical difficulties would preclude the successful use of the control option for the emissions unit under review.\

High-temperature Water Splitting, Photobiological Water Splitting, Photoelectrochemical Water Splitting, Pyrolysis, Photolytic Processes, Renewable Liquid Reforming, and Fermentation are experimental technologies that are not yet commercialized. Therefore, these technologies will be removed from consideration.

Gasification is a commercial technology; however, it would require coal feedstock to be delivered to the facility and will not displace any feedstock necessary for the production of the biofuels. Furthermore, gasification also requires high-temperature steam which would be generated from combustion; therefore, gasification isn't believed to currently reduce criteria pollutant emissions from the proposed levels for the steam-hydrocarbon reforming operation. Therefore, this technology will be removed from consideration.

Step 3 - Rank Remaining Control Technologies by Control effectiveness

Rank	Capture and Control Efficiency	Status
1. Electrolysis	N/A	Alternate Basic Equipment
2. Autothermal Reforming	N/A	Alternate Basic Equipment
3. Partial Oxidation/Grannus Process	N/A	Alternate Basic Equipment
4. 0.0039 lb-PM_{10}/MMBtu	N/A	Achieved in Practice

Step 4 - Cost Effectiveness Analysis

Cost Analyses for Alternate Basic Equipment Options

The cost analysis for ABE options was conducted in the NOx portion of this analysis. The ABE options were determined to not be cost effective.

Step 5 - Select BACT

As shown above, alternate basic equipment hydrogen production technologies are not cost effective. BACT for PM_{10} from the process heater is 0.0039 lb-PM_{10}/MMBtu. The facility is proposing a limit slightly lower than 0.0039 lb-PM_{10}/MMBtu; therefore, BACT is satisfied.

APPENDIX E.4
BACT Analysis for Chemical Plants Valves and Connectors

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 4.12.1

Emissions Unit: Chemical Plants – Valves & Connectors
Equipment Rating: All **Last Update:** TBD

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
VOC	Leak defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 and Maintenance Program pursuant to District Rule 4455		

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

***This is a Summary Page for this Class of Source - Permit Specific BACT**

Best Available Control Technology Analysis

District BACT Guideline 4.12.1

Chemical Plants – Valves and Connectors

Prepared by:
James Harader, Supervising Air Quality Engineer

Reviewed by:
Nick Peirce, Permit Services Manager

I. Introduction

BACT is triggered for VOC emissions from valves and connectors. The District's BACT Clearinghouse includes a guideline, 4.12.1, that addresses VOC emissions from valves and connectors at chemical plants; however, that guideline was last updated on November 26, 2006. Since the guideline is outdated, a new BACT Analysis will be performed to determine BACT for valves and connectors at chemical plants.

II. Source of emissions

VOC emissions occur from leaking valves and connectors. Since emissions from fugitive components are greater than 2.0 lb/day for some of the permit units at this proposed facility, BACT is triggered for VOC emissions.

III. Top-Down BACT Analysis

BACT analysis for VOC Emissions

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

The following BACT clearinghouse references were reviewed to determine whether any chemical plants have been required to employ VOC controls for pumps and compressor seals:

- EPA RACT/BACT/LAER clearinghouse
- CARB BACT clearinghouse
- South Coast AQMD (SCAQMD) BACT clearinghouse
- Bay Area AQMD (BAAQMD) BACT clearinghouse
- Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
- San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse

The EPA RACT/BACT/LAER Clearinghouse and CARB BACT Clearinghouses were searched; however, no guidelines were identified that would apply to valves and connectors at chemical plants.

A search of South Coast AQMD BACT Clearinghouse identified the following requirements:

South Coast BACT Requirements for Non-Major Polluting Facilities	
Category	**BACT Requirement for VOCs**
Compressor Fittings, Open Ended Pipes, Pressure Relief Devices, Valves, Pumps, Sampling Connections, Hatches, Sight-Glasses and Meters in VOC Service	Compliance with South Coast AQMD Rule 1173

Bay Area Air Quality Management District's Clearinghouse and Sacramento Metropolitan AQMD's BACT Clearinghouse did not include any guidelines for valves and connectors operated at chemical plants.

The SJVAPCD clearinghouse includes BACT Guideline 4.12.1 for Chemical Plants – Valves & Connectors; however, the guideline was last updated in November 26, 2006. The requirements are shown in the table below:

SJVAPCD BACT Guideline 4.12.1 (11/26/2006)	
Category	**BACT Requirement for VOCs**
Chemical Plants – Valves & Connectors	Leak defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 and Maintenance Program pursuant to District Rule 4455 (Achieved in Practice)

A review of District rules revealed the following requirements:

Rule	Requirements for VOCs
South Coast Rule 1173 Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants	Leak defined as a reading of methane in excess of: • 50,000 ppm from a component in light liquid service. • 500 ppm from a component in heavy liquid service; or • Leak in excess of 10,000 ppm for a continuous 24 hour period for valves and other components. •
BAAQMD Regulation 8 Rule 18 Equipment Leaks	Leak defined as a reading of methane in excess of 100 ppm for valves and connectors (connectors)

SMAQMD Rule 443 Leaks from Synthetic Organic Chemical and Polymer Manufacturing	Leak defined as a reading in methane equal to or greater than 10,000 ppm above background
SJVAPCD Rule 4455 Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants	Minor Gas Leak defined as a reading of methane between 200 ppm to 10,000 ppm Major Gas Leak defined as a reading of methane greater than 10,000 ppm

A review of District permits for chemical plants revealed the following operations:

Facility Permit	**VOC Control Requirement for Leaks**
Seaboard Energy California C-4261-41-7	Valves and Connectors leak limited to 100 ppmv above background using EPA Method 21
SJV Biodiesel S-8986-3-0	Valves and Connectors leak limited to 100 ppmv above background using EPA Method 21
Calgren Renewable Fuels S-4214-0-0	Valves and Connectors leak limited to 100 ppmv above background using EPA Method 21
Pelican Renewables N-7365-0-0	Valves and Connectors leak limited to 100 ppmv above background using EPA Method 21
Canary Renewables N-7480-2-3	Valves and Connectors leak limited to 100 ppmv above background using EPA Method 21
Aemetis Advanced Fuels Keyes N-7488-0-1	Valves and Connectors leak limited to 100 ppmv above background using EPA Method 21

The following control options were identified based on the above information:

Option 1: Leaks from Valves and Connectors limited to 100 ppmv above background using EPA Method 21

This option is listed as achieved in practice in the District's current BACT Guideline and has been achieved at multiple facilities within the District.

No options more stringent than Option 1 were identified.

Step 2 - Eliminate Technologically Infeasible Options

All of the items listed in step 1 are technologically feasible. Therefore, none can be eliminated.

Step 3 - Rank Remaining Control Technologies by Control effectiveness

Rank	Capture and Control Efficiency	Status
1. Leak defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 and Maintenance Program pursuant to District Rule 4455	N/A	Achieved in Practice

Step 4 - Cost Effectiveness Analysis

There is not technologically feasible control options identified. A cost analysis is not required for achieved in practice control options.

Step 5 - Select BACT

The applicant is proposing the achieved in practice control option of limiting leaks from valves and connectors to 100 ppmv above background. Therefore, BACT for VOC emissions is satisfied.

APPENDIX E.5

BACT Analysis for Chemical Plants Pump and Compressor Seals

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 4.12.2

Emissions Unit: Chemical Plants – Pump and Compressor Seals
Equipment Rating: All **Last Update:** TBD

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
VOC	Leak defined as a reading of methane in excess of 500 ppmv above background when measured per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455		

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

***This is a Summary Page for this Class of Source - Permit Specific BACT**

Best Available Control Technology Analysis

District BACT Guideline 4.12.2

Chemical Plants – Valves and Connectors

Prepared by:
James Harader, Supervising Air Quality Engineer

Reviewed by:
Nick Peirce, Permit Services Manager

I. Introduction

BACT is triggered for VOC emissions from pumps and compressor seals. The District's BACT Clearinghouse includes a guideline, 4.12.2, that addresses VOC emissions from pumps and compressor seals at chemical plants; however, that guideline was last updated on November 27, 2006. Since the guideline is outdated, a new BACT Analysis will be performed to determine BACT for pumps and compressor seals at chemical plants.

II. Source of emissions

VOC emissions occur from leaking pumps and compressor seals. Since emissions from fugitive components are greater than 2.0 lb/day for some of the permit units at this proposed facility, BACT is triggered for VOC emissions.

III. Top-Down BACT Analysis

BACT analysis for VOC Emissions

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

The following BACT clearinghouse references were reviewed to determine whether any chemical plants have been required to employ VOC controls for pumps and compressor seals:

- EPA RACT/BACT/LAER clearinghouse
- CARB BACT clearinghouse
- South Coast AQMD (SCAQMD) BACT clearinghouse
- Bay Area AQMD (BAAQMD) BACT clearinghouse
- Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
- San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse

The EPA RACT/BACT/LAER Clearinghouse and CARB BACT Clearinghouses were searched; however, no guidelines were identified that would apply to valves and connectors at chemical plants.

A search of South Coast AQMD BACT Clearinghouse identified the following requirements:

South Coast BACT Requirements for Non-Major Polluting Facilities	
Category	**BACT Requirement for VOCs**
Compressor Fittings, Open Ended Pipes, Pressure Relief Devices, Valves, Pumps, Sampling Connections, Hatches, Sight-Glasses and Meters in VOC Service	Compliance with South Coast AQMD Rule 1173

Bay Area Air Quality Management District's Clearinghouse and Sacramento Metropolitan AQMD's BACT Clearinghouse did not include any guidelines for pumps and compressor seals operated at chemical plants.

The SJVAPCD clearinghouse includes BACT Guideline 4.12.2 for Chemical Plants – Pumps and Compressor Seals; however, the guideline was last updated in November 27, 2006. The requirements are shown in the table below:

SJVAPCD BACT Guideline 4.12.2 (11/27/2006)	
Category	**BACT Requirement for VOCs**
Chemical Plants – Pumps and Compressor Seals	Leak defined as a reading of methane in excess of 500 ppmv above background when measured per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455

A review of District rules revealed the following requirements:

Rule	Requirements for VOCs
South Coast Rule 1173 Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants	Leak defined as a reading of methane in excess of: • 50,000 ppm from a component in light liquid service. • 500 ppm from a component in heavy liquid service; or • Leak in excess of 10,000 ppm for a continuous 24 hour period for pumps and compressor seals
BAAQMD Regulation 8 Rule 18 Equipment Leaks	Leak defined as a reading of methane in excess of 500 ppm for pumps and compressor seals

SMAQMD Rule 443 Leaks from Synthetic Organic Chemical and Polymer Manufacturing	Leak defined as a reading in methane equal to or greater than 10,000 ppm above background
SJVAPCD Rule 4455 Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants	Minor Gas Leak defined as a reading of methane between 500 ppm to 10,000 ppm Major Gas Leak defined as a reading of methane greater than 10,000 ppm

A review of District permits for chemical plants revealed the following operations:

Facility Permit	**VOC Control Requirement for Leaks**
Seaboard Energy California C-4261-41-7	Pump and Compressor Seal leaks limited to 500 ppmv above background using EPA Method 21
SJV Biodiesel S-8986-3-0	Pump and Compressor Seal leaks limited to 500 ppmv above background using EPA Method 21
Calgren Renewable Fuels S-4214-0-0	Pump and Compressor Seal leaks limited to 500 ppmv above background using EPA Method 21
Pelican Renewables N-7365-0-0	Pump and Compressor Seal leaks limited to 500 ppmv above background using EPA Method 21
Canary Renewables N-7480-2-3	Pump and Compressor Seal leaks limited to 500 ppmv above background using EPA Method 21
Aemetis Advanced Fuels Keyes N-7488-0-1	Pump and Compressor Seal leaks limited to 500 ppmv above background using EPA Method 21

The following control options were identified based on the above information:

Option 1: Leaks from Pumps and Compressor Seals limited to 500 ppmv above background using EPA Method 21

This option is listed as achieved in practice in the District's current BACT Guideline and has been achieved at multiple facilities within the District.

No options more stringent than Option 1 were identified.

Step 2 - Eliminate Technologically Infeasible Options

All of the items listed in step 1 are technologically feasible. Therefore, none can be eliminated.

Step 3 - Rank Remaining Control Technologies by Control effectiveness

Rank	Capture and Control Efficiency	Status
1. Leak defined as a reading of methane in excess of 500 ppmv above background when measured per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455	N/A	Achieved in Practice

Step 4 - Cost Effectiveness Analysis

There is not technologically feasible control options identified. A cost analysis is not required for achieved in practice control options.

Step 5 - Select BACT

The applicant is proposing the achieved in practice control option of limiting leaks from pumps and compressor seals to 500 ppmv above background. Therefore, BACT for VOC emissions is satisfied.

APPENDIX E.6
BACT Analysis for Hydrogen Production Unit and Wastewater Treatment Plant Process Vents

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 4.X.X

Emissions Unit: Hydrogen Production Unit – Reaction Vessel Vents and Wastewater Treatment Vents
Equipment Rating: All **Last Update:** TBD

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
VOC	VOC emissions from process vents not to exceed 0.5 lb/MMscf of hydrogen produced (Equivalent to 96% capture and control)	Use of a Thermal Oxidizer Achieving 99% overall capture and control	

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

***This is a Summary Page for this Class of Source - Permit Specific BACT**

Best Available Control Technology Analysis

District BACT Guideline 4.x.x

Renewable Biodiesel/Aviation Fuel Plant - Hydrogen Production Unit and Wastewater Treatment Unit Vents

Prepared by:
James Harader, Supervising Air Quality Engineer

Reviewed by:
Nick Peirce, Permit Services Manager

I. Introduction

BACT is triggered for VOC emissions from the process vents associated with the hydrogen production unit and the wastewater treatment units associated with this facility. The District's BACT Clearinghouse does not include a BACT Guideline for this type of operation; therefore, a new BACT Analysis will be performed to determine BACT for this operation.

II. Source of emissions

The HPU consists of the following series of reactors:

- Hydrotreater – Converts organic sulfur compounds in the reformer feed into hydrogen sulfide and converts olefins to saturated hydrocarbons using a Co-Mo catalyst.

- Desulfurization Absorber – Removes the hydrogen sulfide from the process gasses using a zinc-oxide catalyst.

- Pre-Reformer – Converts long chain hydrocarbons into naphtha and methane using a zinc catalyst, preparing the gas stream for the Reformer that processes methane and naphtha

- Reformer – Converts methane and naphtha to CO and H_2 using steam and a zinc catalyst.

- High Temperature Shift Converter – Converts remaining CO with H_2O to H_2 and CO_2 using steam and an iron-chromium catalyst.

- Pressure Swing Adsorber (PSA) – removes impurities to produce pure hydrogen (99+%). The removed off gas is reused as fuel in the Reformer.

VOC emissions are emitted from the reactor vents associated with the hydrogen production unit. These VOC emissions are routed to RTO #1 for control of the VOC emissions.

Additionally, a wastewater treatment unit produces clean water for the hydrogen production unit. The wastewater treatment unit includes a digester that creates digester gas laden with VOCs. The digester gas is routed to RTO #1 for control of the VOC emissions.

Emissions from the processes routed to RTO #1 are greater than 2.0 lb-VOC/day; therefore, BACT is triggered for VOC emissions.

III. Top-Down BACT Analysis

BACT analysis for VOC Emissions

Step 1 - Identify All Possible VOC Control Technologies

The following BACT clearinghouse references were reviewed to determine whether any hydrogen product plants have been required to employ VOC controls for emissions from reaction vessel vents and wastewater treatment unit vents.

- EPA RACT/BACT/LAER clearinghouse
- CARB BACT clearinghouse
- South Coast AQMD (SCAQMD) BACT clearinghouse
- Bay Area AQMD (BAAQMD) BACT clearinghouse
- Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
- San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse

The EPA RACT/BACT/LAER Clearinghouse was searched. The following determinations were identified:

RBLC ID: IL-0115 – Wood River Refinery
Process: Hydrogen Plant 2 Vents
Control Requirement: Good Air Pollution Control Practices

RBLC ID: CA-1250 – Taft Ammonia
Process: Hydrogen Product
Control Requirement: Not listed, no add-on controls

RBLC ID: CA-1252 – Taft Ammonia
Process: Hydrogen Product
Control Requirement: Not listed, no add-on controls

RBLC ID: LA-0211 – Garyville Refinery
Process: Hydrogen Plant Steam Vent, Deaerator Vent, and Hydrogen Vent
Control Equipment: None

A search of South Coast AQMD BACT Clearinghouse identified the following requirements:

South Coast BACT Requirements for Non-Major Polluting Facilities	
Category	**BACT Requirement for VOCs**
Reactor with Atmospheric Vent	-Carbon Adsorber; or -Afterburner; or -Refrigerated Condenser; or -Scrubber with Approved Liquid Waste Disposal

Bay Area Air Quality Management District's Clearinghouse and Sacramento Metropolitan AQMD's BACT Clearinghouse did not include any guidelines for hydrogen production plant - reaction vessel vents and wastewater treatment vents.

The SJVAPCD Clearinghouse was searched and does not include any guidelines for hydrogen production plant - reaction vessel vents and wastewater treatment vents.

The only Federal, State, or local Rule found that addresses hydrogen production process vents is South Coast Rule 1189, "Emissions from Hydrogen Plant Process Vents". This rule limits the total VOC emissions from process vents to 0.5 pounds per million standard cubic feet of hydrogen produced. This emission limit is equivalent to approximately 96% control of VOC emissions[13]

A review of District permits for chemical plants revealed the following hydrogen production operations:

Facility Permit	**VOC Control Requirement for Leaks**
Alon Bakersfield Refining S-33-55-23	No controls for reactor vessel vents or wastewater treatment vents listed on permit.

The following control options were identified based on the above information:

Option 1: Limit Emissions from Process Vents to 0.5 lb-VOC/MMSCF

This option is required by SCAQMD Rule 1189. Since this Rule is SIP-approved, the requirement is achieved in practice.

Option 2: Use of a Thermal Oxidizer achieving 99% overall capture and control of VOC emissions

No facilities using this control technology were identified; however, this is a technologically feasible control.

[13] South Coast Rule 1189 considers an emission limit of 2.5 lb-VOC/mmscf of hydrogen produced to be equivalent to 80% control of VOC emissions from the baseline emissions from hydrogen vents. Using these values, the uncontrolled emissions from hydrogen vents is equal to 12.5 lb-VOC/mmscf of hydrogen produced (2.5 lb/mmscf ÷ (1-0.8)).

Option 3: Good Air Pollution Control Practices

This option is less stringent than Option 1, which is achieved in practices. Therefore, this option will be removed from consideration.

Step 2 - Eliminate Technologically Infeasible Options

All of the items listed in step 1 are technologically feasible. Therefore, none can be eliminated.

Step 3 - Rank Remaining Control Technologies by Control effectiveness

Rank	Capture and Control Efficiency	Status
1. Use of a Thermal Oxidizer achieving 99% capture and Control of VOC emissions.	99%	Technologically Feasible
2. VOC emissions from process vents not to exceed 0.5 lb/MMscf of hydrogen produced (Equivalent to 96% capture and control).	96%	Achieved in Practice

Step 4 - Cost Effectiveness Analysis

The applicant is proposing the most effective control technology identified. Therefore, a cost effective analysis is not required.

Step 5 - Select BACT

The applicant is proposing the most effective control technology identified, the use of a thermal oxidizer with an overall VOC control and capture efficiency of 99%. Therefore, BACT for VOC emissions is satisfied.

APPENDIX E.7
BACT Guideline 1.1.2 and Top-Down BACT Analysis for 59 MMBtu/hr Boiler

Back

Best Available Control Technology (BACT) Guideline 1.1.2
Last Update: 11/30/2022

Natural gas or propane fired boilers/steam generators with heat input rate greater than 20 MMBtu/hr**

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	PUC quality natural gas or propane with LPG backup		
SOx	PUC quality natural gas or propane with LPG backup		
PM10	PUC quality natural gas or propane with LPG backup		
NOx	2.5 ppmvd @ 3% O2 (0.003 lb/MMBtu)		
CO	50 ppmvd @ 3% O2 (0.037 lb/MMBtu)		

** This is a Summary Page for this Class of Source. ** This guideline is applicable to units fired solely on natural gas from a PUC or FERC regulated source or propane/LPG. This guideline is not applicable to Oilfield Steam Generators or Electric Utility Steam Generating Units.*

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

This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.

Top-Down BACT Analysis

BACT Analysis for NOx Emissions:

a. **Step 1 - Identify All Possible Control Technologies**

The SJVAPCD BACT Clearinghouse guideline 1.1.2 (Last Updated 11/30/22), identifies achieved in practice and technologically feasible BACT control technologies for NOx from natural gas or propane fired boilers rated greater than 20 MMBtu/hr as follows:

1) 2.5 ppmvd @ 3% O_2 (0.003 lb/MMBtu) - achieved in practice

b. Step 2 - Eliminate Technologically Infeasible Options

None of the above listed control technologies are technologically infeasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 2.5 ppmvd @ 3% O_2 (0.003 lb/MMBtu) – achieved in practice

d. Step 4 - Cost Effectiveness Analysis

Since there are no technologically feasible options identified, a cost analysis is not required.

e. Step 5 - Select BACT

The applicant is proposing to meet the achieved in practice requirement of 2.5 ppmvd NOx @ 3% O_2. Therefore, BACT requirements are satisfied for NOx.

BACT Analysis for SOx Emissions:

a. **Step 1 - Identify All Possible Control Technologies**

The SJVAPCD BACT Clearinghouse guideline 1.1.2 (Last Updated 11/30/22), identifies achieved in practice and technologically feasible BACT control technologies for SOx from natural gas or propane fired boilers rated greater than 20 MMBtu/hr as follows:

1) PUC quality natural gas or propane with LPG Backup

b. Step 2 - Eliminate Technologically Infeasible Options

None of the above listed control technologies are technologically infeasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC quality natural gas or propane with LPG Backup

d. Step 4 - Cost Effectiveness Analysis

Since there are no technologically feasible options identified, a cost analysis is not required.

e. Step 5 - Select BACT

The applicant is proposing to meet the achieved in practice requirement by using PUC quality natural gas fuel. Therefore, BACT requirements are satisfied for SOx.

BACT Analysis for PM10 Emissions:

a. Step 1 - Identify All Possible Control Technologies

The SJVAPCD BACT Clearinghouse guideline 1.1.2 (Last Updated 11/30/22), identifies achieved in practice and technologically feasible BACT control technologies for PM10 from natural gas or propane fired boilers rated greater than 20 MMBtu/hr as follows:

1) PUC quality natural gas or propane with LPG Backup

b. Step 2 - Eliminate Technologically Infeasible Options

None of the above listed control technologies are technologically infeasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC quality natural gas or propane with LPG Backup

d. Step 4 - Cost Effectiveness Analysis

Since there are no technologically feasible options identified, a cost analysis is not required.

e. Step 5 - Select BACT

The applicant is proposing to meet the achieved in practice requirement by using PUC quality natural gas fuel. Therefore, BACT requirements are satisfied for PM10.

APPENDIX E.8
BACT Guideline 7.1.10 and Top-Down BACT Analysis for Organic Material Transfer Operation

Back

Best Available Control Technology (BACT) Guideline 7.1.10
Last Update: 7/19/2018

Organic Liquid Loading Rack

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	Bottom fill loading (submerged pipe fill loading) with dry break couplers, or equivalent; and VOC emissions from the vapor collection and control system less than or equal to 0.015 pounds per 1,000 gallons of organic liquid transferred		

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

This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.

Top-Down BACT Analysis

BACT Analysis for VOC Emissions:

a. Step 1 - Identify All Possible Control Technologies

The SJVAPCD BACT Clearinghouse guideline 7.1.10 (Last Updated 7/9/18), identifies achieved in practice and technologically feasible BACT control technologies for VOC from organic liquid loading racks as follows:

1) Bottom fill loading (submerged pipe fill loading) with dry break couplers, or equivalent, and VOC emissions from the vapor collection and control system less than or equal to 0.015 pounds per 1,000 gallons of organic liquid transferred - achieved in practice

b. Step 2 - Eliminate Technologically Infeasible Options

None of the above listed control technologies are technologically infeasible.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1) Bottom fill loading (submerged pipe fill loading) with dry break couplers, or equivalent, and VOC emissions from the vapor collection and control system less than or equal to 0.015 pounds per 1,000 gallons of organic liquid transferred - achieved in practice

d. Step 4 - Cost Effectiveness Analysis

Since there are no technologically feasible options identified, a cost analysis is not required.

e. Step 5 - Select BACT

The applicant is proposing bottom fill loading with dry break couplers and VOC emissions from the vapor collection and control system less than or equal to 0.015 pounds per 1,000 gallons. Therefore, BACT for VOC emissions is satisfied.

APPENDIX E.9

BACT Guideline 3.1.4 and Top-Down BACT Analysis for Emergency IC Engine Powering a Fire Pump

Back

Best Available Control Technology (BACT) Guideline 3.1.4
Last Update: 3/2/2020

Emergency Diesel-Fired IC Engine Powering a Fire Pump

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Latest EPA Tier Certification level for applicable horsepower range		
NOx	Latest EPA Tier Certification level for applicable horsepower range		
PM10	- 0.1 grams/bhp-hr** (if T-BACT*** is triggered) - 0.15 grams/bhp-hr (if T-BACT*** is not triggered)		
SOx	Diesel fuel with sulfur content no greater than 0.0015% by weight		
VOC	Latest EPA Tier Certification level for applicable horsepower range		

***Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 g/bhhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 g/bhp-hr requirement. ***A site-specific Health Risk Analysis is used to determine if T-BACT is triggered.*

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

This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.

Top Down BACT Analysis for the Emergency IC Engine

BACT Guideline 3.1.4 (March 2, 2020) will be used for this emergency diesel IC engine powering a fire pump. In accordance with the District BACT policy, information from that guideline will be utilized without further analysis.

1. BACT Analysis for NO_X and VOC Emissions:

a. Step 1 - Identify all control technologies

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BACT Guideline 3.1.4 identifies only the following option:

- *Latest EPA Tier Certification level for applicable horsepower range*

To determine the latest applicable Tier level, the following steps were taken:

- Conduct a survey of all the emergency IC engines permitted in the District to determine the latest EPA Tier certification level that has been permitted for the proposed engine size

- Conduct a survey of the major IC engine manufacturers/genset vendors to determine the latest EPA Tier certification level that is readily available for the proposed engine size and use

- Review Title 17 CCR, Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines to determine the latest Tier certification level required in California for the proposed engine size

<u>Survey of Permitted Units</u>:
A review of the emergency standby fire pump IC engines permitted in the District revealed that the District has permitted 98 Tier 3 certified emergency standby fire pump CI engines, ranging in size from 86 bhp to 575 bhp.

The following permitted units were found which utilize Tier 4I IC engines:

- C-8915-1-0 (64 BHP JOHN DEERE MODEL 4045TF290 TIER 4I)
- S-8324-1-0 (64 BHP JOHN DEERE MODEL JU4H-UFAEE8 TIER 4I)
- S-8689-1-0 (64 BHP JOHN DEERE MODEL 4045TF290 TIER 4I)

No Tier 4F certified units have been permitted.

<u>Survey of IC Engine Manufacturers/Genset Vendors</u>:
An internet search for emergency standby fire pump IC engines revealed only one manufacturer, Clark Fire (http://www.clarkefire.com/), which offers Tier 2 and Tier 3 certified units. No Tier 4F certified units could be found.

Stationary ATCM:
The requirements set forth in Table 2 of CARB's Stationary Air Toxic Control Measure (ATCM) for stationary emergency standby diesel-fired IC engines are summarized in the table below.

Table 2: Emission Standards for New Stationary Emergency Standby Direct-Drive Fire Pump Engines > 50 BHP in g/bhp-hr (equivalent EPA Tier level)		
Maximum Engine Power	**NMHC+NOx**	**CO**
50 ≤ bhp < 75	3.5 (Tier 4i)	3.7 (Tier 4i)
75 ≤ bhp < 100	3.5 (Tier 3)	3.7 (Tier 3)
100 ≤ bhp < 175	3.0 (Tier 3)	3.7 (Tier 3)
175 ≤ bhp < 750	3.0 (Tier 3)	2.6 (Tier 3)
≥ 750 bhp	4.8 (Tier 2)	2.6 (Tier 2)

Summary:
Based on a survey of currently permitted units, manufacturer availability, and State ATCM requirements, the District considers the following table to represent the latest available EPA Tier certification levels for this class and category of source at this time:

Engine Size	NOx	VOC	CO
50 ≤ bhp < 100	Tier 4i	Tier 4i	Tier 4i
100 ≤ bhp < 750	Tier 3	Tier 3	Tier 3
≥ 750 bhp	Tier 2	Tier 2	Tier 2

b. Step 2 - Eliminate technologically infeasible options

The control option listed in Step 1 is not technologically infeasible.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because there is only one control option listed in Step 1.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control option remaining under consideration. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

The applicant has proposed to install a 687 bhp Tier 3 certified IC engine. Therefore, BACT for NOx and VOC is satisfied.

2. BACT Analysis for PM_{10} Emissions:

Particulate matter (PM_{10}) emissions occur from the reaction of various elements in the diesel fuel including fuel sulfur.

a. Step 1 - Identify all control technologies

BACT guideline 3.1.4, identifies the following achieved in practice BACT for PM_{10} emissions from emergency diesel IC engines powering a firewater pump:

- 0.1 grams/bhp-hr (if TBACT is triggered)
- 0.15 grams/bhp-hr (if TBACT is not triggered)

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

No ranking needs to be done because the applicant has proposed the achieved in practice option.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control achieved in practice in the ranking list from Step 3. Therefore, per SJVUAPCD BACT policy, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for PM_{10} emissions from this emergency diesel IC engine powering a firewater pump is having certified emissions of 0.15 g-PM_{10}/bhp-hr or less (T-BACT not triggered). The applicant has proposed to install a 687 bhp emergency diesel IC engine powering a firewater pump with certified emissions of 0.087 g/bhp-hr; therefore BACT for PM_{10} emissions is satisfied.

APPENDIX E.10

BACT Guideline 3.1.1 and Top-Down BACT Analysis for Emergency IC Engine Powering an Electrical Generator

Back

Best Available Control Technology (BACT) Guideline 3.1.1
Last Update: 4/29/2022

Emergency Diesel-Fired IC Engine > 50 bhp Powering an Electrical Generator

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	EPA Tier 4 Final certification level or equivalent for applicable horsepower range**		
NOx	EPA Tier 4 Final certification level or equivalent for applicable horsepower range**		
PM10	EPA Tier 4 Final certification level or equivalent for applicable horsepower range**		
SOx	Very low sulfur diesel fuel (15 ppmw sulfur or less)		
VOC	EPA Tier 4 Final certification level or equivalent for applicable horsepower range**		

***The following emission levels are equivalent to the EPA Tier 4 Final certification levels: 50 - < 75 bhp: 3.5 g-(NOx + VOC)/bhp-hr, 0.02 g-PM/bhp-hr, 3.7 g-CO/bhp-hr 75 - < 175 bhp: 0.30 g-NOx/bhp-hr, 0.015 g-PM/bhp-hr, 3.7 g-CO/bhp-hr, 0.14 g-VOC/bhp-hr 175 - = 750 bhp: 0.30 g-NOx/bhp-hr, 0.015 g-PM/bhp-hr, 2.6 g-CO/bhp-hr, 0.14 g-VOC/bhp-hr > 750 bhp: 0.50 g-NOx/bhp-hr, 0.02 g-PM/bhp-hr, 2.6 g-CO/bhp-hr, 0.14 g-VOC/bhp-hr*

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

This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.

BACT Guideline 3.1.1 (April 29, 2022) will be used for this emergency diesel IC engine powering an electrical generator. In accordance with the District BACT policy, information from that guideline will be utilized without further analysis.

1. BACT Analysis for NO_X and VOC Emissions:

a. Step 1 - Identify all control technologies

\

BACT Guideline 3.1.1 identifies only the following options for NOx and VOC.

- EPA Tier 4 Final Certification level or equivalent for applicable horsepower range –achieved in practice

b. Step 2 - Eliminate technologically infeasible options

The control option listed in Step 1 is not technologically infeasible.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because there is only one control option listed in Step 1.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control option remaining under consideration. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

The applicant has proposed to install a Tier 4 final certified IC engine. Therefore, BACT for NOx and VOC is satisfied.

APPENDIX E.11
BACT Guideline 7.3.3 and Top-Down BACT Analysis for Organic Liquid Storage Tanks

Back

Best Available Control Technology (BACT) Guideline 7.3.3
Last Update: 9/1/2021

Floating Roof Organic Liquid Storage or Processing Tank

Pollutant	Achieved in Practice or in the SIP	Technologically Feasible	Alternate Basic Equipment
VOC	Internal Floating Roof Tank meeting requirements of District Rule 4623 or External Domed Floating Roof Tank meeting requirements of District Rule 4623		

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

This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.

BACT Guideline 7.3.3 (September 1, 2021) will be used for the floating roof organic liquid storage tanks. In accordance with the District BACT policy, information from that guideline will be utilized without further analysis.

1. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

BACT Guideline 7.3.3 identifies only the following options for VOC.

- Internal Floating Roof tank meeting requirements of District Rule 4623 or External Domed Floating Roof Tank meeting requirements of District Rule 4623 – achieved in practice

b. Step 2 - Eliminate technologically infeasible options

The control option listed in Step 1 is not technologically infeasible.

c. Step 3 - Rank remaining options by control effectiveness

No ranking needs to be done because there is only one control option listed in Step 1.

d. Step 4 - Cost Effectiveness Analysis

The applicant has proposed the only control option remaining under consideration. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

The applicant has proposed to install organic liquid storage tanks with internal floating roofs meeting the requirements of District Rule 4623. Therefore, BACT is satisfied for VOC emissions from the tanks.

APPENDIX F
HAP Emissions

HAP Emissions by Unit

Device_ID	Process_ID	Device_Name	CAS #	CAS Name	lb/year
20	1	HydroFlex Production Fugitives	71432	Benzene	24.27
			108883	Toluene	23.57
			1330207	Xylenes	48.53
20	2	19.5 MMBtu/hr NG Heater	1151	PAHs-w/o	0.02
			50000	Formaldehyde	2.10
			71432	Benzene	0.99
			75070	Acetaldehyde	0.53
			91203	Naphthalene	0.05
			100414	Ethyl Benzene	1.18
			107028	Acrolein	0.46
			108883	Toluene	4.53
			110543	Hexane	0.79
			1330207	Xylenes	3.37

20	3	27.6 MMBtu/hr NG Heater	1151	PAHs-w/o	0.02
			50000	Formaldehyde	2.97
			71432	Benzene	1.40
			75070	Acetaldehyde	0.75
			91203	Naphthalene	0.07
			100414	Ethyl Benzene	1.67
			107028	Acrolein	0.65
			108883	Toluene	6.41
			110543	Hexane	1.11
			1330207	Xylenes	4.76

20	4	41.5 MMBtu/hr NG Heater	1151	PAHs-w/o	0.04
			50000	Formaldehyde	4.47
			71432	Benzene	2.11
			75070	Acetaldehyde	1.13
			91203	Naphthalene	0.11
			100414	Ethyl Benzene	2.51
			107028	Acrolein	0.98
			108883	Toluene	9.63
			110543	Hexane	1.67
			1330207	Xylenes	7.16

21	1	Hydrogen Production Fugitives	71432	Benzene	10.62
			108883	Toluene	10.32
			1330207	Xylenes	21.24
21	2	184 MMBtu/hr Process Gas & NG	50000	Formaldehyde	8.57
			71432	Benzene	5.98
			75070	Acetaldehyde	7.77
			91203	Naphthalene	0.45
			100414	Ethyl Benzene	3.63
			107028	Acrolein	7.48
			108883	Toluene	120.40
			1330207	Xylenes	47.87
21	3	Hydrogen Production Fugitive Emissions 2	71432	Benzene	26.06
			108883	Toluene	25.31
			1330207	Xylenes	52.12

22	1	59 MMBtu/hr Process Gas & NG	50000	Formaldehyde	2.75
			71432	Benzene	1.92
			75070	Acetaldehyde	2.49
			91203	Naphthalene	0.14
			100414	Ethyl Benzene	1.16
			107028	Acrolein	2.40
			108883	Toluene	38.61
			1330207	Xylenes	15.35

23	1	Naphtha Loading Racks	71432	Benzene	0.08
			98828	Cumene	0.03
			100414	Ethyl Benzene	0.07
			108883	Toluene	0.26
			110543	Hexane	0.20
			1330207	Xylenes	0.33

23	2	7.60 MMBtu/hr RTO NG	1151	PAHs-w/o	0.01
			50000	Formaldehyde	1.13
			71432	Benzene	0.53
			75070	Acetaldehyde	0.29
			91203	Naphthalene	0.02
			100414	Ethyl Benzene	0.63
			107028	Acrolein	0.18
			108883	Toluene	2.44
			110543	Hexane	0.42
			1330207	Xylenes	1.81

23	3	33 MMBtu/hr Process Gas	50000	Formaldehyde	0.01
			71432	Benzene	0.00
			75070	Acetaldehyde	0.01
			91203	Naphthalene	0.00
			100414	Ethyl Benzene	0.00
			107028	Acrolein	0.01
			108883	Toluene	0.08
			1330207	Xylenes	0.03

23	4	Naphtha Storage Tank Fugitives	71432	Benzene	2.25
			98828	Cumene	0.75
			100414	Ethyl Benzene	1.88
			108883	Toluene	7.50
			110543	Hexane	5.63
			1330207	Xylenes	9.38

24	1	Waste Water Treatment	7647010	HCl	267.91

24	2	7.60 MMBtu/hr RTO NG	1151	PAHs-w/o	0.01
			50000	Formaldehyde	1.13
			71432	Benzene	0.53
			75070	Acetaldehyde	0.29
			91203	Naphthalene	0.02
			100414	Ethyl Benzene	0.63
			107028	Acrolein	0.18
			108883	Toluene	2.44
			110543	Hexane	0.42
			1330207	Xylenes	1.81

24	3	33 MMBtu/hr Process Gas	50000	Formaldehyde	0.01
			71432	Benzene	0.00
			75070	Acetaldehyde	0.01
			91203	Naphthalene	0.00
			100414	Ethyl Benzene	0.00
			107028	Acrolein	0.01
			108883	Toluene	0.08
			1330207	Xylenes	0.03

26	1	79.17 MMBtu/Hr Emergency Flare	1151	PAHs-w/o	0.05
			50000	Formaldehyde	4.14
			71432	Benzene	10.51
			75070	Acetaldehyde	0.15
			91203	Naphthalene	0.04
			100414	Ethyl Benzene	5.30
			107028	Acrolein	0.04
			108883	Toluene	1.42
			110543	Hexane	13.95
			1330207	Xylenes	0.33

27	1	687 BHP Emergency DICE	None		

28	1	1,341 BHP Emergency DICE	0.065	3.25	

29	1	203,700 Gallon Naphtha Storage Tank	71432	Benzene	8.52
			98828	Cumene	2.84
			100414	Ethyl Benzene	7.10
			108883	Toluene	28.42
			110543	Hexane	21.31
			1330207	Xylenes	35.52

29	2	Combined Tanks Fugitive Emissions	71432	Benzene	2.87
			98828	Cumene	0.96
			100414	Ethyl Benzene	2.39
			108883	Toluene	9.57
			110543	Hexane	7.17
			1330207	Xylenes	11.96

30	1	203,700 Gallon Naphtha Storage Tank	71432	Benzene	8.52
			98828	Cumene	2.84
			100414	Ethyl Benzene	7.10
			108883	Toluene	28.42
			110543	Hexane	21.31
			1330207	Xylenes	35.52

31	1	153,300 Gallon Slop Storage Tank	71432	Benzene	0.16
			98828	Cumene	0.05
			100414	Ethyl Benzene	0.13
			108883	Toluene	0.52
			110543	Hexane	0.39
			1330207	Xylenes	0.65

32	1	300,300 Gallon Slop Storage Tank	71432	Benzene	0.18
			98828	Cumene	0.06
			100414	Ethyl Benzene	0.15
			108883	Toluene	0.60
			110543	Hexane	0.45
			1330207	Xylenes	0.76

Total HAPs

CAS #	CAS Name	lb/year
1151	PAHs-w/o	0.15
50000	Formaldehyde	27.28
71432	Benzene	107.50
75070	Acetaldehyde	13.42
91203	Naphthalene	0.90
98828	Cumene	7.53
100414	Ethyl Benzene	35.53
107028	Acrolein	12.39
108883	Toluene	320.53
110543	Hexane	74.82
1330207	Xylenes	298.53
7647010	HCl	267.91
	Total HAPs	1166.49

As shown above, each individual HAP is less than 20,000 lb/year (10 tons), and total HAPs are less than 50,000 lb/year (25 tons).

APPENDIX G
Copy of US EPA Protocol for Equipment Leak Emissions Table 2-10 Formulas

TABLE 2-10. PETROLEUM INDUSTRY LEAK RATE/SCREENING VALUE CORRELATIONS[a]

Equipment type/service	Correlation[b,c]
Valves/all	Leak rate (kg/hr) = 2.29E-06 × $(SV)^{0.746}$
Pump seals/all	Leak rate (kg/hr) = 5.03E-05 × $(SV)^{0.610}$
Others[d]	Leak rate (kg/hr) = 1.36E-05 × $(SV)^{0.589}$
Connectors/all	Leak rate (kg/hr) = 1.53E-06 × $(SV)^{0.735}$
Flanges/all	Leak rate (kg/hr) = 4.61E-06 × $(SV)^{0.703}$
Open-ended lines/all	Leak rate (kg/hr) = 2.20E-06 × $(SV)^{0.704}$

[a]The correlations presented in this table are revised petroleum industry correlations.

[b]SV = Screening value in ppmv.

[c]These correlations predict total organic compound emission rates (including non-VOC's such as methane and ethane).

[d]The "other" equipment type was derived from instruments, loading arms, pressure relief valves, stuffing boxes, and vents. This "other" equipment type should be applied to any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

APPENDIX H
Risk Management Review and Ambient Air Quality Analysis Results

San Joaquin Valley Air Pollution Control District
Risk Management Review and Ambient Air Quality Analysis

To:	James Harader – Permit Services
From:	Adrian Ortiz – Technical Services
Date:	July 25, 2023
Facility Name:	AEMETIS ADVANCED PRODUCTS RIVERBANK INC
Location:	5300 CLAUS RD, RIVERBANK
Application #(s):	N-9742-20-0, -21-0, -22-0, -23-0, -24-0, -25-0, -26-0, -27-0, -28-0, -29-0, -30-0, -31-0, -32-0
Project #:	N-1224324

1. Summary

1.1 Risk Management Review (RMR)

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
20-0	1.93	0.05	0.01	2.06E-06	Yes	Yes
21-0	2.58	0.08	0.02	3.55E-06	Yes	Yes
22-0	0.17	0.00	0.00	2.10E-08	No	Yes
23-0	0.20	0.00	0.00	9.78E-07	No	Yes
24-0	0.19	0.00	0.00	1.25E-09	No	Yes
25-0	N/A[1]	N/A[1]	N/A[1]	N/A[1]	No	No
26-0	0.77	0.03	0.00	1.25E-07	No	Yes
27-0	3.81	0.00	N/A[2]	7.76E-07	No	Yes
28-0	1.88	0.00	N/A[2]	2.03E-08	No	Yes
29-0	0.68	0.00	0.00	1.74E-07	No	No
30-0	0.51	0.00	0.00	1.38E-07	No	No
31-0	0.01	0.00	0.00	2.36E-09	No	No
32-0	0.01	0.00	0.00	2.80E-09	No	No
Project Totals	12.60	0.16	0.03	7.07E-06		
Facility Totals	>1	0.18	0.14	1.01E-05		

Notes:
1. Cancer risk, acute and chronic hazard indices were not calculated for Unit 25 since there is no risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.
2. Acute hazard index was not calculated for Unit 7 & 28 since there is no risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

1.2 Ambient Air Quality Analysis (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/m³ for the 24-hour average concentration and 1 μg/m³ for the annual concentration.
4. Modeled PM2.5 concentrations were below the District SIL for non-fugitive sources of 1.2 μg/m³ for the 24-hour average concentration and 0.2 μg/m³ for the annual concentration.

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

Unit # 25-0, 29-0, 30-0, 31-0 & 32-0

1. No special requirements.

Unit # 20-0 (19.5 MMBtu/hr, 27.6 MMBtu/hr, 41.5 MMBtu/hr heaters), 21-0, 22-0, 23-0 & 24-0

1. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction.

Unit # 26-0

1. Operation of the flare shall not exceed 93 hours per calendar year.

Unit # 27-0

1. The PM_{10} emissions rate shall not exceed 0.087 g/bhp-hr based on US EPA certification using ISO 8178 test procedure.
2. 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.
3. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year.

Unit # 28-0

1. The PM_{10} emissions rate shall not exceed 0.022 g/bhp-hr based on US EPA certification using ISO 8178 test procedure.
2. 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.
3. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year.

T-BACT is required for Unit 20 (Hydoflex Production Fugitives) because of emissions of Benzene which is a VOC.

T-BACT is required for Unit 21 (Hydrogen Production Fugitives) because of emissions of Benzene which is a VOC.

2. Project Description

Technical Services received a request to perform a Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) for the following:

- Unit -20-0: HYDROFLEX FUEL PRODUCTION UNIT CONSISTING OF A HYDROGENATION REACTOR, DEWAXING REACTOR, GAS AND LIQUID SEPARATION EQUIPMENT, FIXED-BED CATALYST VESSELS, SOUR GAS TREATMENT EQUIPMENT, A 19.5 MMBTU/HR NATURAL GAS-FIRED PROCESS HEATER WITH AN OXIDATION CATALYST, ULTRA LOW-NOX BURNER AND SELECTIVE CATALYTIC REDUCTION, A 27.6 MMBTU/HR NATURAL GAS FIRED PROCESS HEATER WITH AN OXIDATION CATALYST, ULTRA LOW-NOX BURNER AND SELECTIVE CATALYTIC REDUCTION, AND A 41.5 MMBTU/HR NATURAL GAS-FIRED PROCESS HEATER WITH AN OXIDATION CATALYST, ULTRA LOW-NOX BURNER AND SELECTIVE CATALYTIC REDUCTION SYSTEM; OR EQUIVALENT
- Unit -21-0: HYDROGEN PRODUCTION UNIT CONSISTING OF A HYDROTREATER, PRE-REFORMER, REFORMER, SHIFT CONVERTERS, AND PRESSURE SWING ADSORBER WITH A 184 MMBTU/HR PROCESS GAS AND NATURAL GAS-FIRED HEATER WITH A CO CATALYST, LOW-NOX BURNER, AND SELECTIVE CATALYTIC REDUCTION SYSTEM; OR EQUIVALENT. HYDROGEN PRODUCTION UNIT GAS IS VENTED TO A SHARED THERMAL OXIDIZER (RTO #1 SHARED WITH N-9742-24-0) WITH A 7.6 MMBTU/HR NATURAL GAS-FIRED BURNER
- Unit -22-0: 59 MMBTU/HR NATURAL GAS-FIRED AUXILIARY BOILER WITH CO CATALYST AND LOW NOX BURNER AND SELECTIVE CATALYTIC REDUCTION (SCR) OR EQUIVALENT
- Unit -23-0: MATERIAL TRANSFER OPERATION (RECEIVING OF FEEDSTOCKS AND OFFLOADING OF PRODUCTS VIA A LOADING RACK TO AND FROM TRUCKS AND RAILCARS) VENTED TO A THERMAL OXIDIZER (RTO #2) WITH A 7.6 MMBTU/HR NATURAL GAS FIRED BURNER
- Unit -24-0: WASTEWATER TREATMENT UNIT VENTED TO A SHARED THERMAL OXIDIZER (RTO #1 SHARED WITH N-9742-21-0) WITH A 7.6 MMBTU/HR NATURAL GAS-FIRED BURNER
- Unit -25-0: 10,200 GALLONS PER MINUTE THREE-CELL COOLING TOWER WITH A DRIFT ELIMINATOR
- Unit -26-0: 79.17 MMBTU/HR PROCESS GAS-FIRED EMERGENCY FLARE
- Unit -27-0: 687 BHP (INTERMITTENT) CLARKE MODEL C18H0 TIER 3 CERTIFIED DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIREWATER PUMP
- Unit -28-0: 1,341 BHP (INTERMITTENT) CUMMINS MODEL DQFAD TIER 4F CERTIFIED DIESEL-FIRED EMERGENCY STANDBY IC ENGINE POWERING AN ELECTRICAL GENERATOR

- Unit -29-0: 203,700 GALLON NAPHTHA STORAGE TANK STORAGE TANK WITH AN INTERNAL FLOATING ROOF A MECHANICAL-SHOE PRIMARY SEAL AND A WIPER SECONDARY SEAL
- Unit -30-0: 203,700 GALLON NAPHTHA STORAGE TANK WITH AN INTERNAL FLOATING ROOF A MECHANICAL-SHOE PRIMARY SEAL AND A WIPER SECONDARY SEAL
- Unit -31-0: 153,300 GALLON SLOP STORAGE TANK WITH AN INTERNAL FLOATING ROOF A MECHANICAL-SHOE PRIMARY SEAL AND A WIPER SECONDARY SEAL
- Unit -32-0: 300,300 GALLON SLOP STORAGE TANK WITH AN INTERNAL FLOATING ROOF A MECHANICAL-SHOE PRIMARY SEAL AND A WIPER SECONDARY SEAL

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 units', 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 a 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 units that exceed a cancer risk of one in a million, Toxic Best Available Control Technology (TBACT) must be implemented.

Air toxics emissions for this project were calculated using the following methods:

- Unit 20, 23 & 24 - Natural gas usage rates for the proposed operation were provided by the Permit Engineer. These usage rates were speciated into air toxics using emission factors derived from the table, "Natural Gas Fired External Combustion Equipment", in the 2001 report, Ventura County Air Pollution Control District AB 2588 Combustion Emission Factors.
- Unit 20 & 21 - Volatile organic compound emissions from this proposed operation were provided by the Permit Engineer. These emissions were speciated into air toxics using emission factors derived from the 1991 source tests of central valley sites.
- Unit 26 - Fuel process rates for the proposed operation were provided by the Permit Engineer. These usage rates were speciated into air toxics using the 2001 Ventura County's Air Pollution Control District's emission factors for Natural Gas Fired external

combustion and emission factors from the 2005 report, Final Report Test of TDA's Direct Oxidation Process for Sulfur Recovery.

- Unit 21, 22, 23 & 24 - Air toxic emissions for the Process Heater fueled by Natural Gas and Refinery Gas were calculated using emission factors from December 2009 Emission Estimation Protocol for Petroleum Refineries by the American Petroleum Institute and Western States Petroleum Association.
- Unit 23 & 29 - Emission factors derived from the speciation in the EPA's TANKs program 4.0.9d (2007).
- Unit 27 & 28 - Particulate matter (PM10) emissions for the proposed diesel internal combustion engine was provided by the Permit Engineer. Per OEHHA guidance, all diesel exhaust PM10 is evaluated as diesel particulate matter (CAS# 9901).

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**
20-0	1	Hydroflex Production VOC	Lbs	0.79	6,933
20-0	2	Natural Gas	MMscf	0.02	171
20-0	3	Natural Gas	MMscf	0.03	242
20-0	4	Natural Gas	MMscf	0.04	364
21-0	1	Hydrogen Production VOC	Lbs	0.35	3,035
21-0	2	Process Gas & NG	MMscf	0.18	1,612
21-0	3	Hydrogen Production VOC	Lbs	0.85	7,445
22-0	1	Process Gas & NG	MMscf	0.06	517
23-0	1	Naphtha VOC	Lbs	0.00	13
23-0	2	Natural Gas	MMscf	0.01	67
23-0	3	Process Gas	MMscf	0.03	1
23-0	4	Naphtha VOC	MMscf	0.04	375
24-0	1	Waste Water Treatment VOC	Lbs.	0.06	536
24-0	2	Natural Gas	MMscf	0.01	67
24-0	3	Process Gas	MMscf	0.03	1
26-0	1	NG & Waste Gas	MMscf	0.04	3.54
27-0	1	Diesel PM10	Lbs	0.13	7
28-0	1	Diesel PM10	Lbs	0.07	3
29-0	1	Naphtha VOC	Lbs	0.16	1,421
29-0	2	Naphtha VOC	Lbs	0.05	478
30-0	1	Naphtha VOC	Lbs	0.16	1,421
31-0	1	Naphtha VOC	Lbs	0.00	26
32-0	1	Naphtha VOC	Lbs	0.00	30

Circular Area Source Parameters				
Unit ID	**Unit Description**	**Release Height (m)**	**Radius (m)**	**Area (m^2)**
29-0	203,700 Gallon Naphtha Storage Tank	7.32	4.72	70.00
30-0	203,700 Gallon Naphtha Storage Tank	9.75	4.67	68.50
31-0	153,300 Gallon Slop Storage Tank	9.75	4.77	71.50
32-0	300,300 Gallon Slop Storage Tank	9.75	5.75	103.90

Polygon Area Source Parameters				
Unit ID	**Unit Description**	**Release Height (m)**	**No. Vertices**	**Area (m^2)**
20-0	HydroFlex Production Fugitives	6.10	8	9,956
21-0	Hydrogen Production Fugitives	6.10	4	2,755
21-0	Hydrogen Production Fugitive Emissions 2	6.10	4	2,755
23-0	Naphtha Storage Tank Fugitives	6.10	5	8,521
29-0	Combined Tanks Fugitive Emissions	6.10	5	8,521

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
20-0	41.5 MMBtu/hr NG Heater	9.14	646	5.59	0.91	Vertical
20-0	27.6 MMBtu/hr NG Heater	9.14	720	4.24	0.91	Vertical
20-0	19.5 MMBtu/hr NG Heater	9.14	669	3.06	0.91	Vertical
21-0	184 MMBtu/hr Process Gas & NG	12.19	1089	4.28	1.68	Vertical
22-0	59 MMBtu/hr Process Gas & NG	15.24	429	4.90	1.02	Vertical
23-0	7.60 MMBtu/hr RTO NG	12.19	1089	4.28	1.68	Vertical
23-0	Naphtha Loading Racks	12.19	1089	4.28	1.68	Vertical
23-0	33 MMBtu/hr Process Gas	12.19	1089	4.28	1.68	Vertical
24-0	7.60 MMBtu/hr RTO NG	12.19	1089	4.28	1.68	Vertical
24-0	Waste Water Treatment	12.19	1089	4.28	1.68	Vertical
24-0	33 MMBtu/hr Process Gas	12.19	1089	4.28	1.68	Vertical
26-0	79.17 MMBtu/Hr Emergency Flare	15.57	418	3.10	1.12	Vertical
27-0	687 BHP Emergency DICE	4.88	802	57.82	0.20	Vertical
28-0	1,341 BHP Emergency DICE	4.88	750	21.68	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	2021
NOx	Turlock	Stanislaus	Turlock	2021
PM10	Modesto-14th Street	Stanislaus	Modesto	2021
PM2.5	Modesto-14th Street	Stanislaus	Modesto	2021
SOx	Fresno - Garland	Fresno	Fresno	2021

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
20-0	2	0.12	0.06	0.37	0.06	0.06
20-0	3	0.09	0.00	0.52	0.08	0.08
20-0	4	0.13	0.12	0.78	0.13	0.13
21-0	2	4.83	2.33	3.26	0.70	0.70
22-0	1	0.76	0.17	1.11	0.18	0.18
23-0	2	0.05	0.02	0.03	0.06	0.06
23-0	3	0.19	0.35	0.12	0.00	0.00
24-0	2	0.05	0.02	0.03	0.06	0.06
24-0	3	0.21	0.02	0.13	0.00	0.00
26-0	1	NA[1]	NA[1]	NA[1]	NA[1]	NA[1]
27-0	1	NA[1]	NA[1]	NA[1]	NA[1]	NA[1]
28-0	1	NA[1]	NA[1]	NA[1]	NA[1]	NA[1]

Notes:
1. Units 26-0, 27-0 & 28-0 are intermittent sources as defined in APR-1920. In accordance with APR-1920, compliance with short-term (i.e., 1-hour, 3-hour,8-hour and 24-hour) standards is not required.

Emission Rates (lbs/year)						
Unit ID	Process	NOx	SOx	CO	PM10	PM2.5
20-0	2	1,053	487	3,205	512	512
20-0	3	745	689	4,537	725	725
20-0	4	1,120	1,036	6,818	1,091	1,091
21-0	2	9,735	20,489	28,550	6,125	6,125
22-0	1	2,284	1,473	9,694	1,551	1,551
23-0	2	410	190	248	506	506
23-0	3	002	003	1,026	000	000
24-0	2	410	190	248	506	506
24-0	3	007	001	1,102	000	000
26-0	1	503	112	000	370	370
27-0	1	201	000	000	007	007
28-0	1	074	001	000	003	003

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**
20-0	41.5 MMBtu/hr NG Heater	9.14	646	5.59	0.91	Vertical
20-0	27.6 MMBtu/hr NG Heater	9.14	720	4.24	0.91	Vertical
20-0	19.5 MMBtu/hr NG Heater	9.14	669	3.06	0.91	Vertical
21-0	184 MMBtu/hr Process Gas & NG	12.19	1089	4.28	1.68	Vertical
22-0	59 MMBtu/hr Process Gas & NG	15.24	429	4.90	1.02	Vertical
23-0	7.60 MMBtu/hr RTO NG	12.19	1089	4.28	1.68	Vertical
23-0	Naphtha Loading Racks	12.19	1089	4.28	1.68	Vertical
23-0	33 MMBtu/hr Process Gas	12.19	1089	4.28	1.68	Vertical
24-0	7.60 MMBtu/hr RTO NG	12.19	1089	4.28	1.68	Vertical
24-0	Waste Water Treatment	12.19	1089	4.28	1.68	Vertical
24-0	33 MMBtu/hr Process Gas	12.19	1089	4.28	1.68	Vertical
26-0	79.17 MMBtu/Hr Emergency Flare	15.27	418	1.01	0.64	Vertical
27-0	687 BHP Emergency DICE	4.88	802	57.82	0.20	Vertical
28-0	1,341 BHP Emergency DICE	4.88	750	21.68	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. However, the cancer risk for one or more units in this project is greater than 1.0 in a million. **In accordance with the District's Risk Management Policy, the fugitive emission sources from Units 20 and 21 are approved with 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 I
Quarterly Net Emission Change

Quarterly Net Emissions Change (QNEC)

The QNEC is entered into PAS database and subsequently reported to CARB. For seasonal sources, or where the emissions differ quarter to quarter, then evaluate each pollutant for each quarter separately. The QNEC is calculated for each pollutant, for each unit, as the difference between the post-project quarterly potential to emit (PE2) and the pre-project quarterly potential to emit (PE1).

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.

Quarterly NEC [QNEC] for Unit N-9742-20-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	968.25	0	968.25
SO_X	553	0	553
PM_{10}	582	0	582
CO	3,492.75	0	3,492.75
VOC	1,836.25	0	1,836.25

Quarterly NEC [QNEC] for Unit N-9742-21-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	2,532	0	2,532
SO_X	5,166.25	0	5,166.25
PM_{10}	1,658.25	0	1,658.25
CO	7,315	0	7,315
VOC	960.5	0	960.5

Quarterly NEC [QNEC] for Unit N-9742-22-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	558.75	0	558.75
SO_X	368.25	0	368.25
PM_{10}	387.75	0	387.75
CO	2,325.75	0	2,325.75
VOC	71	0	71

Quarterly NEC [QNEC] for Unit N-9742-23-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	100.75	0	100.75
SO_X	53.25	0	53.25
PM_{10}	128.75	0	128.75
CO	62.5	0	62.5
VOC	381.25	0	381.25

Quarterly NEC [QNEC] for Unit N-9742-24-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	0	0	0
CO	0	0	0
VOC	133.75	0	133.75

Quarterly NEC [QNEC] for Unit N-9742-25-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	33	0	33
CO	0	0	0
VOC	0	0	0

Quarterly NEC [QNEC] for Unit N-9742-26-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	125.75	0	125.75
SO_X	55.5	0	55.5
PM_{10}	92.5	0	92.5
CO	684.5	0	684.5
VOC	259	0	259

Quarterly NEC [QNEC] for Unit N-9742-27-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	50.25	0	50.25
SO_X	0	0	0
PM_{10}	1.75	0	1.75
CO	17.5	0	175
VOC	1.25	0	1.25

Quarterly NEC [QNEC] for Unit N-9742-28-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	18.5	0	18.5
SO_X	0.25	0	0.25
PM_{10}	0.75	0	0.75
CO	74	0	74
VOC	5.25	0	5.25

Quarterly NEC [QNEC] for Unit N-9742-29-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	0	0	0
CO	0	0	0
VOC	449	0	449

Quarterly NEC [QNEC] for Unit N-9742-30-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	0	0	0
CO	0	0	0
VOC	355.25	0	355.25

Quarterly NEC [QNEC] for Unit N-9742-31-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	0	0	0
CO	0	0	0
VOC	6.5	0	6.5

Quarterly NEC [QNEC] for Unit N-9742-32-0			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	0	0	0
CO	0	0	0
VOC	7.5	0	7.5