Public Notice

Public Hearing about Red Rock Biofuels Holdings' Proposed Air Quality Permit: Nov. 16, 2020

The Oregon Department of Environmental Quality invites the public to attend a virtual public hearing and to comment on the Red Rock Biofuels' proposed air quality permit, known officially as a Standard Air Contaminant Discharge Permit.

Summary

The proposed permit is a renewal and moderate technical modification. The current permit was issued on June 24, 2015 and expired on June 1, 2020. A complete and timely renewal application was submitted by the permittee, so the existing permit will remain in effect until this renewal is issued

How do I participate?

Attend the virtual public hearing to learn about the permit application, ask any questions you might have and provide oral or written comments on the proposed permit. You can also submit written comments by mail, fax or email.

Hearing details

When: 5:30 p.m., **Monday, Nov. 16, 2020**

Where: This hearing will take place by webinar and phone only.

Zoom meeting address:
https://us02web.zoom.us/j/82617004325?pwd=b2ZYQXJoLzIyd0VIbTlpcitkZTVwdz09

Conference call number:
833-548-0276 or 833-548-0282

ID: 826 17000 4325

Send written comments by mail, fax or email to:

Nancy Swofford, Permit Coordinator
475 NE Bellevue Dr., Suite 110
Bend, OR 97701
Fax: 541-388-8283
Email: eraqpermits@deq.state.or.us

Comments due: 5 p.m., **Thursday, Nov. 19, 2020**

About the facility

This is a Standard Air Contaminant Discharge Permit renewal and moderate technical modification for Red Rock Biofuels, LLC at 18281 Kadrmas Road in Lakeview.

The facility has not been constructed or operated to date. The company will construct a new biofuels facility and associated infrastructure to produce jet fuel, diesel fuel and naphtha from a woody biomass feedstock consisting primarily of mill and forest residues or with natural gas as a feedstock.

What air pollutants does the permit regulate?

This permit regulates emissions of the pollutants listed in the table at the end of this document.

How does DEQ determine permit requirements?

DEQ evaluates types and amounts of pollutants and the facility's location, and determines permit requirements according to state and federal regulations.

What special conditions are in this permit?

The permittee must develop, install and maintain best management practices to minimize fugitive and visible dust emissions, including enclosed material handling processes with enclosed storage and air pollution equipment.

How does DEQ monitor compliance with the permit requirements?

This permit would require the facility to monitor pollutants using federally approved monitoring practices and standards.

Formulas to calculate emissions are contained in the permit. The permittee is required to calculate facility-wide emissions and submit an emissions report to DEQ semi-annually. DEQ will conduct onsite inspections to ensure compliance with emission limitations.

What happens after the hearing?

DEQ considers and responds to all comments received and may modify the proposed permit based on comments. If a facility meets all legal requirements, DEQ will issue the facility's air quality permit.

State of Oregon
Department of Environmental Quality

Eastern Region
Air Quality Program
475 NE Bellevue Dr., #110
Bend, OR 97701
Phone: 541-388-6146
866-863-6668
Fax: 541-388-8283
Contact: Walt West,
Permit Writer

www.oregon.gov/DEQ

DEQ is a leader in restoring, maintaining and enhancing the quality of Oregon's air, land and water.

Date Issued: 10/14/2020
By: Nancy Swofford
Permit No.: 19-0016

Where can I get more information?

Find out more and view the draft documents online at DEQ's "Public Notices" page or contact Nancy Swofford, Permit Coordinator:

Phone: 541-633-2021 or 866-863-6668
Fax: 541-388-8283
Email: eraqpermits@deq.state.or.us

You may also view the draft permit and related documents in person at the Lake County Library District at 26 S 'G' Street or at the DEQ office in Bend. For a review appointment, call Nancy Swofford at 541-633-2021.

Accessibility information

DEQ can provide documents in an alternate format or in a language other than English upon request. Call DEQ at 800-452-4011 or email deqinfo@deq.state.or.us.

Emissions Limits

Criteria Pollutants: Table 1 below presents maximum allowable emissions of criteria pollutants for the facility. The current emission limit reflects maximum emissions the facility can emit under the existing permit. The proposed emission limit reflects maximum emissions the facility would be able to emit under the proposed permit. Typically, a facility's actual emissions are less than maximum limits established in a permit; however, actual emissions can increase up to the permitted limit.

Table 1

Criteria Pollutants	Current Limit (tons/yr)	Proposed Limit (tons/yr)
Particulate matter	24	24
Small particulate matter (PM_{10})	14	14
Fine particulate matter	9	9
Nitrogen oxides	39	39
Sulfur dioxide	39	39
Carbon monoxide	99	99
Volatile organic compounds	39	39
Greenhouse gases	272,719	226,136

For more information about criteria pollutants, go to EPA's "Criteria Air Pollutants" page.

Hazardous Air Pollutants: Red Rock Biofuels is not a major source of hazardous air pollutants, however EPA has determined that businesses similar to this facility, as a group, emit enough hazardous air pollutants to warrant regulation. Therefore, this source is subject to the following National Emission Standard for Hazardous Air Pollutants: 40 CFR Part 63, Subpart ZZZZ (Stationary reciprocating internal combustion engines). Table 2 summarizes the hazardous air pollutants that trigger the NESHAP. More detailed information can be found in the Review Report.

Table 2

Hazardous Air Pollutants	Potential Emissions (tons/yr)
Hexane	5.29
Xylene	3.12
Toluene	1.81
Various Other HAPs	1.98
Total HAPs	**12.20**

For more information about hazardous air pollutants, go to:
Health Effects Notebook for Hazardous Air Pollutants

OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY
STANDARD
AIR CONTAMINANT DISCHARGE PERMIT

Eastern Region
475 NE Bellevue Dr., Suite 110
Bend, OR 97701

This permit is being issued in accordance with the provisions of ORS 468A.040 and based on the land use compatibility findings included in the permit record.

ISSUED TO:

Red Rock Biofuels Holdings, Inc.
4745 Boardwalk Dr., Suite D101
Fort Collins, CO 80525

INFORMATION RELIED UPON:

Application No.: 31078, 32396
Date Received: 12/4/2019, 5/18/2020

PLANT SITE LOCATION:

Red Rock Biofuels, LLC
18281 Kadrmas Rd.
Lakeview, OR 97630

LAND USE COMPATIBILITY FINDING:

Approving Authority: Lake County
Approval Date: 2/12/2015

ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY

Mark W. Bailey, Eastern Region Air Quality Manager

Date

Source(s) Permitted to Discharge Air Contaminants (OAR 340-216-8010):

Source Description	**Activity Type**	**SIC**	**NAICS**	**DEQ Table 1 Permit Category Code(s)**
Organic or Inorganic Chemical Manufacturing and Distribution	Primary	2869	325194	Part B, 57
Onsite Power Generation	Secondary	4911	221112	Part B, 27
Boilers Steam and Heat Generation	Secondary	4961	221330	Part B, 13

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1.0 DEVICE, PROCESS AND POLLUTION CONTROL DEVICE (PCD) IDENTIFICATION

The devices, processes and pollution control devices regulated by this permit are the following:

Devices and Processes Description	Device ID	Pollution Control Device Description	PCD ID
Biomass Truck Receiving #1	EU01	Baghouse	CE10
Biomass Truck Receiving #2	EU02	Baghouse	CE15
Biomass Conveying & Shredder	EU03	Surge Bin Vent Filters	CE11
Biomass Conveyor System	EU04	---	---
Biomass Storage Pile	EU05	---	---
Biomass Handling	EU06	---	---
Gasification System	EU12	Gasifier Flare Exhaust Stack	CE07
Gasifier Flare Pilot	EU15	Gasifier Flare Exhaust Stack	CE07
Gas Turbine W/Duct Burner & HRSG	EU33	Selective Catalytic Reduction (SCR)	CE06
Recycle Heater	EU34		CE06
Diesel Scrubber	EU35	Gasifier Flare Exhaust Stack	CE07
POX Unit	EU36	Gasifier Flare Exhaust Stack	CE07
Water Scrubber	EU37	H_2S Water Scrubber	CE12
Sour Gas Shift	EU41	Gasifier Flare Exhaust Stack	CE07
Oil Water Separator	EU38	---	---
Amine CO_2 Removal	EU16	---	---
Fisher-Tropsch Synthesis	EU17	Gasifier Flare Exhaust Stack	CE07
Hydroprocessing and Distillation	EU18	Gasifier Flare Exhaust Stack	CE07
Auto Thermal Reformer (ATR)	EU42	Gasifier Flare Exhaust Stack	CE07
Cooling Tower	EU20	---	---
Emergency Fire Pump	EU22	---	---
Reactor Charge Heater	EU39	---	---
Fractionator Feed Heater	EU40	---	---
Biochar Handling and Conveying	EU24	Flare	CE07
Biochar Silo	EU25	Vent Filter	CE08
Uncaptured Biochar Loadout	EU26	---	---
Product Loadout - Truck	EU27	Carbon Canister	CE13
Product Loadout - Rail	EU28	Carbon Canisters	CE14
Truck Traffic	EU30	---	---
Front End Loader #1	EU31	---	---
Front End Loader #2	EU32	---	---
Equipment Leaks	FS10	---	---
Storage Tanks (TK01 thru TK08)	TK#	---	---

2.0 GENERAL EMISSION STANDARDS AND LIMITS

2.1. Visible Emissions

The permittee must comply with the following visible emission limits from air contaminant sources other than fugitive emission sources, as applicable:

a. Opacity must be measured as a six-minute block average using EPA Method 9. [OAR 340-208-0110(2)]
b. Any devices or processes installed, constructed or modified on or after April 16, 2015 must not equal or exceed 20% opacity. [OAR 340-208-0110(4)]

2.2. Particulate Matter Emissions

The permittee must comply with the following particulate matter emission limits.

a. Particulate matter emissions from any fuel burning equipment (except solid fuel burning devices that have been certified under OAR 340-262-0500) must not exceed 0.10 grains per dry standard cubic foot, corrected to 50% excess air. [OAR 340-228-0210(2)(c)]
b. Particulate matter emissions from any device or process (other than fugitive emissions sources, fuel burning equipment, refuse burning equipment, or solid fuel burning devices certified under OAR 340-262-0500) must not exceed 0.10 grains per dry standard cubic foot. [OAR 340-226-0210(2)(c)]
c. Non-fugitive particulate matter emissions from processes listed in OAR 340-226-0300 must not exceed the process weight emission standards shown in Table 1 of OAR 340-226-0310.

2.3. Fugitive Emissions

a. The permittee must take reasonable precautions to prevent fugitive dust emissions from leaving the property of a source. Reasonable precautions include, but are not limited to: [OAR 340-208-0210]
    i. Using, where possible, water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;
    ii. Applying water or other suitable chemicals on unpaved roads, materials stockpiles, and other surfaces which can create airborne dusts;
    iii. Enclosing (full or partial) materials stockpiles in cases where application of water or other suitable chemicals are not sufficient to prevent particulate matter, including dust, from becoming airborne;
    iv. Installing and using hoods, fans and fabric filters to enclose and vent the handling of dusty materials;
    v. Installing adequate containment during sandblasting or other similar operations;
    vi. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne; and
    vii. Promptly removing earth or other material that does or may become airborne from paved streets.

b. In no case may fugitive dust emissions leave the property of a source for a period or periods totaling more than 18 seconds in a six-minute period. Fugitive emissions must be measured by EPA Method 22 with the minimum observation time of six minutes.

2.4. Particulate Matter Fallout

The permittee must not cause or permit the deposition of any particulate matter larger than 250 microns in size at sufficient duration or quantity, as to create an observable deposition upon the real property of another person. [OAR 340-208-0450]

2.5. Nuisance and Odors

The permittee must not cause or allow the emission of odorous or other fugitive emissions so as to create nuisance conditions off the permittee's property. Nuisance conditions will be verified by DEQ personnel. [OAR 340-208-0300]

2.6. Complaint Log

The permittee must maintain a log of all complaints received by the permittee in person, in writing, by telephone or through other means that specifically refer to air pollution, odor, or nuisance concerns associated with the permitted facility. Documentation must include: [OAR 340-214-0114]

a. The date the complaint was received;
b. The date and time the complaint states the condition was present;
c. A description of the pollution or odor condition;
d. The location of the complainant/receptor relative to the plant site;
e. The status of plant operation or activities during the complaint's stated time of pollution or odor condition; and
f. A record of the permittee's actions to investigate the validity of each complaint and a record of actions taken for complaint resolution.

2.7. Fuels and Fuel Sulfur Content

The permittee must not use any fuels other than natural gas, propane, butane or any of the ASTM grade fuel oils listed below. The sulfur content cannot exceed:

a. 0.0015% sulfur by weight for ultra low sulfur diesel; and,
b. 0.5% sulfur by weight for ASTM Grade 2 distillate oil. [OAR 340-228-0110]

2.8. Woody Biomass

The permittee must not receive more than 438,000 tons of woody biomass in any 12-month consecutive period.

2.9. Flare

The permittee must have the capability to combust all start-up, shut down, and upset process gas emissions in the flare.

3.0 SPECIFIC PERFORMANCE AND EMISSION STANDARDS

3.1. General Provision Requirements – NSPS Subpart A

The permittee must comply with all applicable provisions of 40 CFR Part 60, Subpart A, including but not limited to the following. (the following summarizes applicable requirements of Subpart A, but is not intended to supersede the subpart):

a. Notification and recordkeeping: [40 CFR 60.7]
   i. The permittee must maintain records of the occurrence and duration of any startup, shutdown or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]
   ii. The permittee must maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system or monitoring device calibration checks; adjustment or maintenance performed on these systems or devices; all other information required by 40 CFR Part 60, recorded in a permanent form, suitable for inspection. [40 CFR 60.7(f)]

b. The permittee must not build, erect, install or use any article machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]

c. At all times including periods of startup, shutdown and malfunction, the permittee shall, to the extent practicable, maintain and operate any affected facility, including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Department which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspections of the source. [40 CFR 60.11]

3.2. The permittee must comply with all applicable provisions and standards of 40 CFR Part 60, Subpart KKKK for the gas turbine (EU33) at the selective catalytic reduction (SCR) unit. (Refer to 40 CFR Part 60, Subpart KKKK and/or Subpart A for definitions of terminology. These conditions summarize the applicable requirements of Subparts KKKK, but are not intended to supersede the subpart.):

a. Nitrogen oxides standards:
   i. The permittee must not cause to be discharged into the atmosphere from the gas turbines (EU33) any gases that contain nitrogen oxides (expressed as NO_2) in excess of 25 ppm corrected to 15% oxygen or 1.2 lb/MWh, whichever is greater, in accordance with 40 CFR 60.4320(a).
   ii. Emissions in excess of the limits in Conditions 3.1.a. during periods of startup, shutdown and malfunction shall not be considered a violation in accordance with 40 CFR 60.8(c). However, for purposes of excess emission reports required by 40 CFR 60.7(c), an excess emission is any 30 operating day rolling average for all periods of unit operation, including startup, shutdown and malfunction in accordance with 40 CFR 60.4350(h) and 60.4375(a). Nitrogen oxide emissions must be measured in accordance with Condition 6.1.e.

b. Sulfur dioxides standards:
   i. The permittee must not burn in the gas turbine any fuel which contains total potential sulfur emissions in excess of 0.060 lb/MMBtu-heat input in accordance with 40 CFR 60.4330(a)(2). The sulfur content of the fuels must be verified in accordance with Condition 6.1.g. for natural gas.

3.3. The Fractionator Feed Heater (EU40) boiler must comply with the applicable requirements in the New Source Performance Standards (NSPS) Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units 40 CFR Part 60, Subpart Dc**.**

3.4. The naphtha product and off spec tanks must comply with the applicable requirements in the New Source Performance Standards (NSPS), Standards of Performance for Volatile Organic Liquid Storage Vessels, 40 CFR Part 60 Subpart Kb and/or Subpart A for definitions of terminology. This condition summarizes the applicable requirements of Subpart Kb, but is not intended to supersede the subpart.

a. VOC standard for the naphtha product and off spec tanks- The permittee must equip the naphtha product and off spec tanks with a fixed roof in combination with an internal floating roof meeting the following specifications: [40 CFR 60.112b(a)(1)]
   i. The internal floating roof must rest or float on the liquid surface (but not necessarily in complete contact with it) inside the storage vessel. 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 its leg supports, the process of filling, emptying or refilling must be accomplished as rapidly as possible. [40 CFR 60.112b(a)(1)(i)]
   ii. The internal floating roof must be equipped with two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous. [60.112b(a)(1)(ii)(B)]
   iii. Each opening in a non-contact 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. 40 CFR 60.112b(a)(1)(iii)]

iv. 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 automatic gauge float must be bolted except when they are in use. [40 CFR 60.112b(a)(1)(iv)]

v. 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. [40 CFR 60.112b(a)(1)(v)]

vi. 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. [40 CFR 60.112b(a)(1)(vi)]

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

viii. 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 a gasketed sliding cover. [40 CFR 60.112b(a)(1)(viii)]

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

b. Testing and procedures. The permittee must: [40 CFR 60.113b(a)(3)]

i. Visually inspect the vessel at least every 5 years. The inspection must include the internal floating roof, the primary seal, the secondary wiper, gaskets, slotted membranes, and sleeve seals each time the 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 the atmosphere, or the slotted membrane has more than 10 percent open area, the permittee must repair the items as necessary so that none of the deficiencies specified in this paragraph 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 5 years. [40 CFR 60.113b(a)(4)]

ii. Notify the Department in writing at least 30 days prior to the filling, or refilling of each storage vessel for which an inspection is required by this Condition to afford the Department the opportunity to have an observer present. If the inspection is not planned and the permittee could not have known about the inspection 30 days in advance of refilling the tank, the permittee must notify the Department at least 7 days prior to the refilling of the storage vessel. The 7-day notice must be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification, including the documentation, may be made in writing and sent by express mail so that it is received by the Department at least 7 days prior to the refilling. 40 CFR 60.113b(a)(5)]

3.5. The permittee must comply with the applicable requirements in the New Source Performance Standards (NSPS) Standards of Performance for Equipment Leaks of VOC, 40 CFR Part 60, Subpart VVa. (Refer to 40 CFR Part 60, Subpart VVa and/or Subpart A for definitions of terminology. This condition summarizes the applicable requirements of Subpart VVa, but is not intended to supersede the subpart.)

a. General standards:
   i. The permittee must demonstrate compliance with the requirements for all equipment within 180 days of initial startup. [40CFR 60.482-1a(a)]
b. Standards for pumps:
   i. Each pump in light liquid service must be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485a(b), except as provided in 40 CFR 60.482-1a(c) and (f) and 40 CFR 60.482-2a(d), (e), and (f). [40 CFR 60.482-2a(a)(1)]
   ii. Each pump in light liquid service must be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal. [40 CFR 60.482-2a(a)(2)]
   iii. If an instrument reading of 2,000 ppm or greater is measured, a leak has been detected. [40 CFR 60.482-2a(b)(1)]
   iv. If there are indications of liquid dripping from a pump seal, the permittee can either designate it as a leak, or monitor the pump within 5 days as specified in 40 CFR 60.485a(b) and use the criteria in permit Condition 3.5.b.iii. to determine whether the pump is leaking. [40 CFR 60.482-2a(b)(2)]
   v. When a leak is detected it must be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in Condition 3.5.i. [40 CFR 60.482-2a(c)(1)]
   vi. A first attempt at repair must be made no later than 5 calendar days after each leak is detected. [40 CFR 60.482-2a(c)(2)]
c. Standards for compressors:
   i. Each compressor must be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere. [40 CFR60.482-3a(a)]
   ii. Each compressor seal system must be operated with the barrier fluid at a pressure that is greater than the compressor box pressure or be equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions. [40 CFR60.482-3a(b)]
   iii. The barrier fluid must be in heavy liquid service or shall not be in VOC service. [40 CFR60.482-3a(c)]
   iv. Each barrier fluid system must be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both. [40 CFR60.482-3a(d)]
   v. Each barrier fluid system must be checked daily or be equipped with an audible alarm. The permittee must determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system or both. [40 CFR60.482-3a(e)]
   vi. If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined in Condition 3.5.c.v. a leak is detected. [40 CFR60.482-3a(f)]
   vii. When a leak is detected, it must be repaired as soon as practicable, but not later than 15 calendar days after it is detected. [40 CFR60.482-3a(g)]

d. Standards for pressure relief devices in gas/vapor service:
   i. Except during pressure releases, each pressure relief device in gas/vapor service must be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background as determined by the methods specified in 40 CFR 60.485a(c). [40 CFR 60.482-4a(a)]
   ii. After each pressure release, the pressure relief device must be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in Condition 3.5.d.i. [40 CFR 60.482-4a(b)(1)]
   iii. No later than 5 calendar days after the pressure release, the pressure relief device must be monitored to confirm the condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR 60.485a(c). [40 CFR 60.483-4a(b)(2)]
   iv. Any pressure relief device that is equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device is exempted from the requirements of Conditions 3.5.d.i. through 3.5.d.iii. [40 CFR 60.482-4a(c)]
   v. Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of Conditions 3.5.d.i. through 3.5.d.iii. provided a new rupture disk is installed as soon as practicable after each pressure release, but no later than 5 days after each pressure relief, except as provided in Condition 3.5.i. [40 CFR 60.482-4a(d)]

e. Standards for sampling connection systems:
   i. Each sampling connection system must be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in 40 CFR 60.482-1a(c). [40 CFR 60.482-5a(a)]
   ii. Each closed-purge, closed-loop, or closed-vent system shall comply with the following requirements: [40 CFR 60.482-5a(b)]
      (a) Gases displaced during filling of the sample container are not required to be collected or captured;
      (b) Containers that are part of a closed purge system must be covered or closed when not being filled or emptied;
      (c) Gases remaining in the tubing or piping between the closed-purge system valves and sample container valves after the valves are closed and the sample container is disconnected are not required to be collected or captured;
      (d) Each closed-purge, closed-loop, or closed-vent system must be designed and operated to meet one of the requirements in 40 CFR 60.482-5a(b)(4).
      (e) In-situ sampling systems and sampling systems without purges are exempt from Condition 3.5.e. [40 CFR 60.482-5a(c)]

f. Standards for open-ended valves or lines:
   i. Each open-ended valve or line must be equipped with a cap, blind flange, plug or a second valve, except as provided in 40 CFR 60.482-1a(c). [40 CFR 60.482-6a(a)(1)]

ii. The cap, blind flange, plug or second valve must seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. [40 CFR 60.482-6a(a)(2)]

iii. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves, but must comply with Condition 3.5.f.ii at all other times. [40 CFR 60.482-6a(c)]

iv. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from Condition 3.5.f. [40 CFR 60.482-6a(d)]

v. Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block-and-bleed system are exempt from the requirements of Condition 3.5.f. [40 CFR 60.482-6a(e)]

g. Standards for valves in gas/vapor service and light liquid service:

i. Each valve must be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485a(b), except as provided in 40 CFR 60.482-1a(c) and (f), 60.483-1a, and 60.483-2a. [40 CFR 60.482-7a(a)(1)]

ii. If an instrument reading of 500 ppm or greater is measured, a leak is detected. [40 CFR 60.482-7a(b)]

iii. Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected. The permittee may elect to subdivide the valves into two or three subgroups and monitor each subgroup in a different month during the quarter. [40 CFR 60.482-7a(c)(1)]

iv. If a leak is detected, the valve must be monitored monthly until a leak is not detected for two successive months. [40 CFR 60.482-7a(c)(2)]

v. When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in Condition 3.5.i. A first attempt at repair must be made no later than 5 calendar days after each leak is detected. [40 CFR 60.482-7a(d)]

vi. Valves that have no detectable emissions (as determined by 40 CFR 60.482-7a(f)), are unsafe to monitor (as determined by 40 CFR 60.482-7a(g)), or are difficult to monitor (as determined by 40 CFR 60.482-7a(h)) are exempt from the requirements of this condition.

h. Standards for pressure relief devices in light liquid service: [40 CFR 60.482-8a]

i. If evidence of a potential leak is found by visual, audible, olfactory or any other detection method, the permittee must either eliminate the visual, audible, olfactory or other indication of potential leak within 5 calendar days of detection; or

ii. Monitor the equipment within 5 days by the methods specified in 40 CFR 60.485a(b). When monitoring the equipment an instrument reading of 10,000 ppm or greater is considered detection of a leak. When a leak is detected it must be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in Condition 3.5.i.

i. Delay of repair:

i. Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown.

Repair of this equipment must occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit. [40 CFR 60.482-9a(a)]

ii. Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service. [40 CFR 60.482-9a(b)]

iii. Delay of repairs of valves and connectors will be allowed if: [40 CFR 60.482-9a(c)]

(a) The permittee demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay or repair; and

(b) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with 40 CFR 60.482-10a.

iv. Delay of repair for pumps will be allowed if: [40 CFR 60.482-9a(d)]

(a) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system; and

(b) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

v. Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown. [40 CFR 60.482-9a(e)]

vi. When delay of repair is allowed for a leaking pump, valve or connector that remains in service, the pump valve or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition. [40 CFR 60.482-9a(f)]

j. Standards for closed vent systems and control devices:

i. Vapor recovery systems must be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent. [40 CFR 60.482-10a(b)]

ii. Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816ºC. [40 CFR 60.482-10a(c)]

iii. Flares used to comply with this subpart must comply with the requirements of §60.18. [40 CFR 60.482-10a(d)]

iv. The permittee must monitor the control devices used to comply with this subpart to ensure that they are operated and maintained in conformance with their designs. [40 CFR 60.482-10a(e)]

v. Each closed vent system must be inspected according to the procedures and schedule specified in §60.482-10a(f)(1) and in §60.482-10a(f)(2). [40 CFR 60.482-10a(f)]

vi. If the vapor collection system or closed vent system is constructed of hard-piping, the permittee must conduct initial and annual visual inspections for visible, audible or olfactory indications of leaks. [40 CFR 60.482-10a(f)(1)(i) and (ii)]

vii. If the vapor collection system or closed vent system is constructed of ductwork, the permittee must conduct an initial and annual inspections according to the procedures in §60.485a(b). [40 CFR 60.482-10a(f)(2)(i) and (ii)]

viii. Leaks, as indicated by an instrument reading greater than 500 ppmv above the background or by visual inspection, must be repaired as soon as practical except as provided in Condition 3.5.j.ix. [40 CFR 60.482-10a(g)]

ix. Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the permittee determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from the delay of repair. Repair of such equipment must be completed by the end of the next process unit shutdown. [40 CFR 60.482-10a(h)]

x. Closed vent systems and control devices used to comply with provisions of this subpart must be operated at all times when emissions may be vented to them. [40 CFR 60.482-10a(m)]

k. Standards for connectors in gas/vapor service and in light liquid service:

i. The permittee must initially monitor all connectors in the process unit for leaks within 12 months of initial startup. [40 CFR 60.482-11a(a)]

ii. Except as allowed in 40 CFR 60.482-1a(c), all connectors in gas and vapor and light liquid service must be monitored to detect leaks by the method specified in 40 CFR 60.485a(b) and as applicable, 40 CFR 60.485a(c). If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected. [40 CFR 60.482-11a(b)(1) and (2)]

iii. If 0.5% or more of the connectors in the process unit were leaking during the previous monitoring, subsequent monitoring must occur within 12 months. [40 CFR 60.482-11a(b)(3)(i)]

iv. If less than 0.5% but greater than or equal to 0.25% of the connectors in the process unit were leaking during the previous monitoring, subsequent monitoring must occur within 4 years. The permittee may comply with this monitoring schedule by monitoring at least 40% of the connectors within 2 years, providing all connectors have been monitored by the end of the 4-year monitoring period. [40 CFR 60.482-11a(b)(3)(ii)]

v. If less than 0.25% of the connectors in the process unit were leaking during the previous monitoring, the permittee must monitor at least 50% of the connectors within 4 years of the start of the monitoring period. If 0.35% or more of the connectors monitored during the 4-year period are found to leak, the permittee must monitor all connectors that have not yet been monitored as soon as practical, but within the next 6 months. At the conclusion of the monitoring, a new monitoring period shall be started pursuant to Condition 3.5.k, based on the percent of leaking connectors. If less than 0.35% of the connectors monitored during the 4-year period are found to leak, the permittee must monitor all connectors that have not yet been monitored within 8-years of the start of the monitoring period. [40 CFR 60.482-11a(b)(3)(iii)]

vi. If, during monitoring, a connector is found to be leaking, it must be monitored once within 90 days of repair to confirm that it is not leaking. [40 CFR 60.482-11a(b)(3)(iv)]

vii. The permittee must keep a record of the start date and end date of each monitoring period. [40 CFR 60.482-11a(b)(3)(v)]

viii. When a leak is detected it must be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in Condition 3.5.i. A first attempt at repair must be made no later than 5 calendar days after detection. [40 CFR 60.482-11a(c)]

ix. Any connector that is designated unsafe to monitor is exempt from the requirements of this condition if the permittee demonstrates that the connector is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of monitoring, and the permittee has a written plan that requires monitoring of the connector as frequently as practicable during safe to monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the connector as required in this condition. [40 CFR 60.482-11a(d)]

x. Any connector that is inaccessible or is ceramic or ceramic lined is exempt from the monitoring, leak repair, recordkeeping and reporting requirements of this condition. However, if any inaccessible, ceramic, or ceramic lined connector is observed by visual, audible, olfactory or other means to be leaking, the indications of leak shall be eliminated as soon as practicable. [40 CFR 60.482-11a(f)]

l. Test methods and procedures are specified in 40 CFR 60.485a.

3.6. The permittee must comply with the applicable requirements in the New Source Performance Standards (NSPS), Standards of Performance for VOC Emissions from Distillation Operations, 40 CFR Part 60, Subpart NNN. (Refer to 40 CFR Part 60, Subpart NNN and/or Subpart A for definitions of terminology. This condition summarizes the applicable requirements of Subpart NNN, but is not intended to supersede the subpart.)

a. Affected facilities include the Fischer-Tropsch unit (EU17), AuthoThermal Reformer (EU42), Sour Gas Shift (EU41) and the Hydroprocessing and Distillation unit (EU18).

b. The permittee must operate applicable distillation operations with a vent stream flow rate less that 0.008 scm/min. [60CFR60.660(c)(6)]

c. The permittee must use Method 2, 2A, 2C or 2D as appropriate for determination of the volumetric flow rate. [40CFR60.664(h)]

d. The permittee must demonstrate compliance with flow rate requirements in §60.660(c)(6) with the following submittals:

i. Submit any change in equipment or process that increases the operating vent stream flow rate above the low flow exemption level, including a measurement of the new vent stream flow rate, as recorded under §60.665(l)(5):

(a) The initial report shall be submitted within 6 months after the initial start-up date.

(b) These must be reported as soon as possible after the change and no later than 180 days after the change.

(c) These reports may be submitted either in conjunction with semiannual reports or as a single separate report.

(d) A performance test must be completed with the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and E_{TOC}. The performance test is subject to the requirements of §60.8 of the General Provisions.

ii. Submit an initial report including a flow rate measurement using the test methods specified in §60.664 and in accordance with Condition 7.1.d.ii. [40CFR60.665(o)]

3.7. The permittee must comply with the applicable requirements in the New Source Performance Standards (NSPS), Standards of Performance for VOC Emissions from Reactor Processes, 40 CFR Part 60, Subpart RRR. (Refer to 40 CFR Part 60, Subpart RRR and/or Subpart A for definitions of terminology. This condition summarizes the applicable requirements of Subpart RRR, but is not intended to supersede the subpart.)

a. Affected facilities include the pyrolysis/gasifier reactor and FT reactor.

b. The permittee must operate all applicable reactor processes with a vent stream flow rate less than 0.011 scm/min. Each unit will discharge into a recovery system that will be entirely enclosed and, therefore, each will have a vent stream flow rate less than 0.011 scm/min. [60CFR60.700(c)(4)]

c. The permittee must use Method 2, 2A, 2C or 2D as appropriate for determination of the volumetric flow rate. [40CFR60.704(g)]

d. The permittee must demonstrate compliance with flow rate requirements in §60.700(c)(4) with the following submittals:

i. Submit any change in equipment process that increases the operating vent stream flow rate above the low flow exemption level, including a measurement of the new vent stream flow rate, as recorded under §60.705(1)(4):

(a) The initial report shall be submitted within 6 months after the initial start-up date.

(b) These must be reported as soon as possible after the change and no later than 180 days after the change.

(c) These reports may be submitted either in conjunction with semiannual reports or as a single separate report.

(d) A performance test must be completed with the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and E_{TOC}. The performance test is subject to the requirements of §60.8 of the General Provisions.

ii. Submit an initial report including a flow rate measurement using the test methods specified in §60.704 and in accordance with Condition 7.1.e.ii [40CFR60.705(o)]

3.8. The emergency fire pump must comply with the applicable requirements in the New Source Performance Standards (NSPS), Standards of Performance for the fire pump Compression Ignition (CI) Internal Combustion Engines (ICE), 40 CFR Part 60, Subpart IIII and the National Emissions Standards for Hazardous Air Pollutant (NESHAP), Standard for Hazardous Air Pollutant for stationary reciprocating internal combustion engines, 40 CFR Part 63, Subpart ZZZZ.

a. 40 CFR Part 60 Subpart IIII, NSPS requirements are applicable to the fire pump Compression Ignition (CI) Internal Combustion Engines (ICE). The fire pump engine must comply with the emissions standards in Table 4 of this subpart for all pollutants. [40 CFR 60.4205(c)]

Subpart IIII of Part 60 Table 4 - Emission Standards for Stationary Fire Pump Engines

Maximum Engine Power	Model Year(s)	NMHC + NOX	PM
225≤KW<450 (300≤HP<600)	2009 +	4.0 g/KW-hr (3.0 g/hp-hr)	0.20 g/KW-hr (0.15 g/hp-hr)

b. The permittee must comply with the fire pump engine standards set forth in §60.4205 over the entire life of the engine. [40 CFR 60.4206]

4.0 OPERATION AND MAINTENANCE REQUIREMENTS

4.1. Operation of Pollution Control Devices and Processes

The permittee must operate and maintain air pollution control devices and emission reduction processes at the highest reasonable efficiency and effectiveness to minimize emissions. Air pollution control devices and components must be in operation and functioning properly at all times when the associated emission source is operating. [OAR 340-226-0120]

4.2. Highest and Best Practicable Treatment and Control

The permittee must provide the highest and best practicable treatment and control of air contaminant emissions in every case so as to maintain overall air quality at the highest possible levels, and to maintain contaminant concentrations, visibility reduction, odors, soiling and other deleterious factors at the lowest possible levels as provided below. [OAR 340-226-0100]

4.3. Operation, Monitoring and Maintenance Plan

The permittee must submit an Operation, Monitoring and Maintenance (OM&M) Plan to DEQ within 60 days of permit issuance. The OM&M Plan must include those items necessary to ensure proper functioning emission control devices including instrument calibration, appropriate operating conditions, correction action levels, troubleshooting, inspection requirements and frequencies, and maintenance requirements. The OM&M Plan must be maintained onsite and be made available upon request. The plan must be reviewed at least annually and updated as needed. [OAR 340-226-0120(1)(a)] The OM&M Plan, at a minimum, must include the following components:

a. *Baghouses and Vent Filters:* The OM&M Plan must include the following minimum monitoring, as applicable, that ensures the baghouses and vent filters are being operated at their highest reasonable efficiency and effectiveness to minimize emissions of particulate air contaminants ($PM/PM_{10}/PM_{2.5}$):

i. At least daily when operating, the permittee must inspect each baghouse and vent filter, record the pressure drop through the baghouses and vent filters in accordance with Conditions 6.2.a.i & 6.2.a.ii. and complete a visual survey of the device to determine if fugitive emissions from the baghouses and vent filters are being adequately controlled. The results of the inspections and pressure differential must be recorded in a log.

ii. At least quarterly the permittee must inspect the baghouses and vent filters to ensure the following applicable devices are working properly: sweep chains; fans and dampers, including applicable proper fan balancing; abort gate/damper actuator and seals; spark detection systems; and any alarms associated with proper function of the baghouses and vent filters. The results of the inspections and any repairs must be recorded in a log.

iii. If deficiencies are noted during an inspection, the permittee must take actions as expeditiously as possible to ensure each baghouse and vent filter is operated in compliance with this permit. The results of any repairs or replacements must be recorded in a log.

b. *Carbon Canisters:* The OM&M Plan must include the following minimum monitoring, as applicable, that ensures the carbon canisters are being operated at its highest reasonable efficiency and effectiveness to minimize emissions of volatile organic compound (VOC) contaminants:

i. At least daily when performing fuel load-out, the permittee must inspect each carbon canisters, record the hours of operations of each carbon canister, the operating pressure differential in accordance with Condition 6.2.a.iv and perform a visual survey of the device to determine if VOC emissions are being adequately controlled. The results of the inspections, hours of operation and pressure differential must be recorded in a log.

ii. If deficiencies are noted during an inspection, the permittee must take actions as expeditiously as possible to ensure the carbon canisters are operated in compliance with this permit. The results of any repairs or replacements must be recorded in a log.

c. *Flare:* The OM&M Plan must include the following minimum monitoring, as applicable, that ensures the flare is operated at its highest reasonable efficiency and effectiveness to ensure all process gases emissions from start-up, shut down and upset conditions are combusted before released to the atmosphere:

i. The flare must be equipped with a heat-sensing device at the pilot light to indicate the continuous presence of a pilot flame in accordance with Condition 6.2.a.iii.;

ii. The pilot flame temperature must be recorded in a log;

iii. Natural gas and process gas flow indicators that measure gas volumes combusted at the flare; and

iv. The permittee must have the capability to meet the requirements of 40 CFR 60.18.

v. If deficiencies are noted during an inspection, the permittee must take actions as expeditiously as possible to ensure the flare will operate in compliance with this permit. The results of any repairs and adjustments must be recorded in a log.

d. *Operation and Maintenance for Emergency Stationary RICE:* The OM&M Plan for the Stationary Emergency Fire Pump (EU22) Reciprocating Internal Combustion Engine (RICE) must include the following requirements: [40 CFR 63.6640(f)]

i. At all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions; [40 CFR 63.6605(b)]

ii. Change oil and filter every 500 hours of operation or annually, whichever comes first. [40 CFR 63. 6603(a), Table 2d(4)(a)] The permittee may elect to comply with the oil analysis requirements of §63.6625(i) in lieu of the oil change requirement. Oil analyses must be conducted at the same frequency as the oil change requirement;

iii. Inspect air filter every 1,000 hours of operation or annually, whichever comes first; [40 CFR 63. 6603(a), Table 2d(4)(b)]

iv. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary; [40 CFR 63. 6603(a), Table 2d(4)(c)]

v. The permittee must operate and maintain the engine according to the manufacturer's emission-related written instructions, including operation and maintenance instructions. If the permittee develops their own maintenance plan and it is approved by DEQ, that plan may substitute for the manufacturer's instructions; [40 CFR 63.6625(e) and 40 CFR 63.6640(a), Table 6(9)]]

vi. During periods of startup, minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply; and [40 CFR 63. 6603(a), Table 2d]

vii. The permittee must operate and maintain the stationary RICE according to the manufacturer's emission related operation and maintenance instructions. [40 CFR 63.6640(a), Table 6(9)]

viii. The permittee must install a non-resettable hour meter on the engine, if one is not already installed. [40 CFR 63.6625(f)]

5.0 PLANT SITE EMISSION LIMITS

5.1. Plant Site Emission Limits (PSEL)

The permittee must not cause or allow plant site emissions to exceed the following: [OAR 340-222-0040 and/or OAR 340-222-0041, OAR 340-222-0060]

Pollutant	Limit	Units
PM	24	tons per year
PM_{10}	14	
$PM_{2.5}$	9	
SO_2	39	
NO_X	39	
CO	99	
VOC	39	
GHGs (CO_{2e})	226,136	

5.2. Annual Period

The annual plant site emission limits apply to any 12-consecutive calendar month period. [OAR 340-222-0035]

6.0 COMPLIANCE DEMONSTRATION

6.1. Continuous Emission Monitoring Requirements

The permittee must monitor the operation and maintenance of the facility and associated air contaminant control devices as follows: [OAR 340-226-0120]

a. The permittee must monitor and record the amount of natural gas used in the gas turbine and duct burner (EU33) and recycle heater (EU34) on an hourly basis.
b. Since it is unlikely that the visible emissions limits could be exceeded while burning natural gas, visible emissions monitoring is not required while burning natural gas.
c. The permittee must install, certify, operate, maintain and record the output of fuel flow meters for natural gas.
d. The permittee must determine and record the heat input (million Btu/hr) to the gas turbine, duct burner and the recycle heater (EU33 and EU34) for every hour or part of an hour any fuel is combusted.
e. The permittee must install, certify, operate, maintain and record the output of a NO_x CEMS (consisting of a NO_x pollutant concentration monitor and an O_2 diluent monitor) at the gas turbine, duct burner and the recycle heater emission units (EU33 and EU34), with automated DAHS for measuring and recording NO_x concentration (ppm) and at emission rates (lb/MMBtu and lb/hr) discharged to the atmosphere in accordance with 40 CFR 75.10(a)(2) and 75.12. [40 CFR 60.4345]
   i. The data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm and lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of 40 CFR 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly CO_2 concentration is less than 1.0 percent CO_2), a diluents cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations. [40 CFR 60.4350(b)]
   ii. The mass emission rate in pounds per hour must be calculated as follows:

$$M_{NOxg} = ER_{NOx} \times HI_g$$

Where:

	M_{NOxg}	=	Hourly mass of NO_x emissions from the combustion of pipeline natural gas, lb/hr
	ER_{NOx}	=	NO_x emission rate in lb/MMBtu as measured by the CEMS
	HI_g	=	Hourly heat input of pipeline natural gas, calculated using procedures in Appendix F of 40 CFR 75, in MMBtu/hr
		=	$(Q_g \times GCV_g)/10000$
Where:	Q_g	=	fuel consumption in 100 scf/hr
	GCV_g	=	gross calorific value of natural gas in Btu/scf provided by the natural gas supplier on a monthly basis.

iii. The permittee must ensure that all CEMS meet the equipment, installation and performance specifications in 40 CFR 75, Appendix A. [40 CFR 75.10(b)]

iv. The permittee must ensure that all CEMS are in operation at all times that the facility combusts any fuel and that the following requirements are met: [40 CFR 75.10(d)]

(a) The permittee must ensure that each CEMS and component thereof is capable of completing a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute interval. The permittee must reduce all NO_x concentration and NO_x emission rate data to 1-hour averages. The permittee must compute these averages from four or more data points equally spaced over each 1-hour period, except during periods when calibration, quality assurance, or maintenance activities pursuant to 40 CFR 75.21 and Appendix B of 40 CFR 75 are being performed. During these periods, a valid hour must consist of at least two data points separated by a minimum of 15 minutes. For combined monitoring systems (NO_x – diluent), the hourly emission rate is valid only if the hourly average concentration from each of the component monitors is valid.

(b) Failure of a NO_x CEMS to acquire the minimum number of data points comprising a valid hour, as specified in this condition, will result in the loss of such component data for the entire hour. The permittee must estimate and record emission or flow data for the missing hour by means of the automated DAHS, in accordance with 40 CFR 75, Subpart D.

(c) Notwithstanding Condition 6.1.e.iv.(b), only quality assured data from the CEMS shall be used to identify excess emissions for the purposes of Condition 3.2.a. Periods where missing data substitution procedures in Subpart D of Part 75 are applied, are to be reported as monitor downtime in the excess emissions and monitoring performance report required under Condition 10.4.b. [40 CFR 60.4350(d)]

v. The hourly average concentration of NO_x in parts per million, corrected to 15% oxygen, and emissions rates in lb/hr and lb/MMBtu-heat input must be recorded at the end of each clock hour that the combustion turbine is operating.

vi. For purposes of Condition 3.2.a., a 30-day rolling average NO_x emission rate is the arithmetic average of all hourly NO_x emission data in ppm measured by the CEMS for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_x emission rates for the preceding 30 unit operating days if a valid NO_x emission rate is obtained for at least 75 percent of all operating hours. [40 CFR 60.4380(b)]

vii. The permittee must ensure that the CEMS and component thereof is capable of accurately measuring, recording and reporting data, and must not incur a full scale exceedance. [40 CFR 75.10(f)]

viii. Whenever the permittee makes a replacement, modification or change in the certified CEMS, including the automated DAHS, that significantly affects the ability of the system to measure or record the NO_x emission rate, the permittee must recertify the CEMS or component in accordance with 40 CFR 75.20(b).

ix. The permittee must operate, calibrate and maintain the CEMS used according to the quality assurance and quality control procedures in Appendix B of 40 CFR 75. [40 CFR 75.10(b) and 75.21(a)]

x. The permittee must ensure that all calibration gases used to quality assure the operation of the instrumentation required by this permit must meet the definition in 40 CFR 72.2. [40 CFR 75.21(c)]

xi. If an out-of-control period occurs to a monitor or CEMS, the permittee must take corrective action and repeat the tests applicable to the "out-of-control parameter" in accordance with 40 CFR 75.24.

xii. Whenever a valid hour of NO_x emissions rate data has not been measured and recorded, the permittee must provide substitute data in accordance with 40 CFR 75.30 through 75.33.

xiii. Each watt meter, steam flow meter, and each pressure or temperature measurement device used for compliance monitoring purposes, shall be installed, calibrated, maintained and operated according to manufacturer's instructions. [40 CFR 60.4345(d)]

xiv. The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in this condition. For the CEMS and fuel flow meters, the permittee may satisfy the requirements of this condition by implementing the QA program and plan described in Section 1 of Appendix B to 40 CFR 75. [40 CFR 60.4345(e)]

f. The permittee must install, calibrate, maintain, operate and record the output of a continuous emissions monitoring system for measuring carbon monoxide emissions and diluent oxygen from the gas turbine (EU33) and recycle heater (EU34) at the selective catalytic reduction (SCR).

i. The CO CEMS must, at a minimum, conform with DEQ's Continuous Monitoring Manual revised April 2015.

ii. Mass emissions of carbon monoxide must be recorded each clock hour that the gas turbine and/or recycle heater are operating using the following equation:

$$M_{CO} = C_{CO}/10^6 \times MW_{CO}/385 \times F_d \times 20.9/(20.9\text{-}\%O_2) \times HI$$

Where:

M_{CO}	=	Hourly mass of CO emissions, lb/hr
C_{CO}	=	Hourly average CO concentration, ppm (uncorrected)
$1/10^6$	=	Conversion from ppm to a fraction
MW_{CO}	=	Molecular weight of CO – 28 lb/lbmole
385	=	Dry standard cubic feet per lbmole at 14.7 psia and 68°F
F_d	=	Dry fuel factor – 8710 dscf/MMBtu for natural gas
HI	=	Hourly heat input = cubic feet of natural gas burned times the most recent heating value, MMBtu/hr

iii. The concentration of CO in parts per million, corrected to 15% oxygen, and emission rate in pounds per hour must be recorded each clock hour that the combustion turbine and/or recycle heater are operating as a hourly average and an 8-hour rolling average (at the end of each clock hour, a new eight hour average is calculated and recorded using the most recent hourly average and the previous seven hourly averages).

g. The permittee must demonstrate compliance with Condition 3.2.b. by maintaining a natural gas tariff sheet that verifies the natural gas burned in the gas turbine (EU33) contains a total sulfur content of 20 grains per 100 standard cubic feet or less, in accordance with 40 CFR 60.4365(a). A copy of the tariff sheet must be maintained on-site and be available for DEQ review upon request.

6.2. Other Control Device Monitoring Requirements

a. Unless otherwise approved in writing by DEQ, the permittee will inspect, record and maintain the following action levels:
   i. Daily baghouse (CE10) and (CE15) pressure drops between 0.1 inches w.c. and 6.0 inches w.c.;
   ii. Daily vent filters (CE11) and (CE08) pressure drops between 0.1 inches w.c. and 6.0 inches w.c.;
   iii. Weekly volume of natural gas used in the flare pilot (CE07) to ensure sufficient and good combustion practices are achieved when burning process gas; and,
   iv. Daily carbon canisters (CE13) and (CE14) operating pressure differential is maintained below the maximum 10 psi at the truck and rail product load-out.
b. The exceedance of an action level shall not be considered a violation of an emission limit in this permit but failure to take corrective action is a violation. [OAR 340-226-0120(2)(d)]

6.3. Fugitive Emissions Monitoring Requirements

At least once per week, the permittee must conduct a fugitive emissions inspection of the plant, including but not limited to the following activities:

a. Conduct a 30 minute Method 22 emissions test at the downwind fence line to verify that no visible emissions are leaving the plant boundary. If visible emissions are observed leaving the plant boundary for more than 18 seconds in a six minute period, the permittee must take immediate corrective action including but not limited to applying water to dusty areas of the plant.
b. Inspect all material transfer points and enclosures and clean up excess material.

6.4. PSEL Compliance Monitoring using Emission Factors

The permittee must calculate the emissions for each 12-consecutive calendar month period based on the following calculation for each pollutant except GHGs: [OAR 340-222-0080]

$$E = \Sigma(EF \times P) \times 1 \text{ ton}/2000 \text{ pounds}$$

Where:

E	=	pollutant emissions (tons/year);
Σ	=	symbol representing “summation of”;
EF	=	pollutant emission factor (see Condition 14.0);
P	=	process production (see Condition 15.0)

6.5. PSEL Compliance for Tank Emissions

The permittee must use the most recent version of EPA TANKs or equivalent AP-42 algorithm to calculate monthly emissions from the Jet Fuel tank (TNK01), Jet Fuel Day Tank 1 (TNK02), Jet Fuel Day Tank 2 (TNK03), Diesel Tank (TNK04), Diesel Day Tank 1 (TNK06), Naphtha Tank (TNK07), and Off-Spec Tank (TNK08).

6.6. PSEL Compliance for Equipment Leak Fugitives

The permittee must use the procedures outlined in EPA's Protocol for Equipment Emissions Estimates, Synthetic Organic Manufacturing Industry (SOCMI) – EPA document 453/R-95-017. If the Average Emissions Factor Approach is used to estimate equipment leak fugitives, then the following equation and assumptions shall be used to calculate equipment leak fugitives:

$$E_{VOC} = \sum(F_A * WF_{VOC} * N) * (1 - C_{EF})$$

Where:

E_{VOC} = Emission rate of VOC from all equipment in the stream of a given type (lb/hr);
F_A = Applicable average emission factor for the equipment type from Condition 14.0 (lb/hr/source);
WF_{VOC} = Average weight fraction of VOC in the stream;
N = Number of pieces of equipment of the applicable equipment type in the stream;
C_{EF} = LDAR control efficiency for the equipment type (0.87 for gas valves, 0.84 for light liquid valves, 0.69 for light liquid pumps, 0.93 for connectors, 0 for all other equipment).

6.7. Emission Factors

The permittee must use the default emission factors provided in Condition 14.0 for calculating pollutant emissions, unless alternative emission factors are approved in writing by DEQ. The permittee may request or DEQ may require using alternative emission factors provided they are based on actual test data or other documentation (e.g., AP-42 compilation of emission factors) that has been reviewed and approved by DEQ. [OAR 340-222-0080]

6.8. Greenhouse Gas Emissions

The permittee must calculate greenhouse gas emissions in metric tons and short tons for each 12-consecutive calendar month period to determine compliance with the GHG PSEL by using the following: [OAR 340-215-0040]

a. DEQ Fuel Combustion Greenhouse Gas Calculator
https://www.oregon.gov/deq/FilterDocs/ghgCalculatorFuelCombust.xlsx

6.9. PSEL Compliance Monitoring

The permittee must demonstrate compliance with the PSEL by totaling the emissions from all point sources calculated under Conditions 6.1, 6.5, 6.6 and 6.8. [OAR 340-222-0080]

7.0 SOURCE TESTING

7.1. Source Testing Requirements

An initial performance test must be conducted on the gas turbine recycle heater units within 60 days of achieving the maximum production rate but no later than 180 days after startup.

a. The permittee must conduct a source test of the gas turbine to demonstrate compliance with Condition 3.2.a. and 3.2.b. The recycle heater must not be operating during this compliance source test of the gas turbine. During the gas turbine source test, the following parameters must be monitored and recorded: [40 CFR 60.4400]
   i. Grain loading in gr/dscf;
   ii. Natural gas usage (MMscf/hr and MMBtu/hr);
   iii. Nitrogen Oxides emissions in ppm, lb/MWh and lb/MMBtu, corrected to 15% O_2;
   iv. Nitrogen Oxides emissions in lb/MMBtu;
   v. Electrical and thermal output;
   vi. Stack gas flow rate;
   vii. The permittee will demonstrate compliance with Condition 3.2.b. by providing a copy of the natural gas tariff sheet that verifies the natural gas burned in the gas turbine (EU33) contains a total sulfur content of 20 grains per 100 standard cubic feet or less, in accordance with 40 CFR 60.4365(a).
b. The permittee must conduct a source test of the combined recycle heater and gas turbine emissions at the SCR stack for formaldehyde and ammonia slip as well as to verify emission factors for CO, VOCs and $PM/PM_{10}/PM_{2.5}$ used in Condition 14.0 to determine compliance with the PSELS of Condition 5.1. units within 60 days of achieving the maximum production rate but no later than 180 days after startup and one year prior to the permit expiration date. The following parameters must be monitored and recorded:
   i. Visible emissions as measured by EPA Method 9 for a period of at least eighteen minutes during or within 30 minutes before or after each test run;
   ii. Grain loading in gr/dscf;
   iii. Natural gas usage (MMscf/hr);
   iv. Total heat input (MMBtu);
   v. Formaldehyde use EPA Method 323 unless an alternative test methos is approved by DEQ;
   vi. Conditional test method CTM-027 must be used for ammonia emissions, unless an alternative test method is approved by DEQ. Three 1-hour tests shall be performed under normal operating load range. During the source test the permittee shall record the following information for the unit being tested;
      (a) Electrical and thermal output;
      (b) Total heat input (MMBtu); and

(c) Ammonia injection rate (lb/hr)

vii. Ammonia emissions should be reported as follows:
(a) ppmvd;
(b) ppmvd @ 15% O_2;
(c) lb/hr; and
(d) Ammonia emissions in lb/lb NH_3 input.

viii. VOCs using EPA Method 18, 25A or 320, unless an alternative test method is approved by DEQ;

ix. Particulate matter using EPA Methods 1-5 and 202, or other test methods approved by DEQ:
(a) The total particulate (filterable & condensable) emission results for EP02 must be reported as gr/dscf corrected to 50% excess air, lbs/hr, and lbs/MMscf.
(b) Each test run must be of sufficient duration and volume to collect a representative amount of particulate matter. Refer to ODEQ Source Sampling Manual, Vol. 1, 2015, Section 2.7.

x. PM_{10} and $PM_{2.5}$ emissions must be measured using EPA Methods 1-4, 201A & 202, or other test methods approved by DEQ.
(a) The test results must be reported as lbs/hr, and lbs/MMscf heat input in accordance with EPA Method 19.
(b) The testing must be conducted concurrently with the particulate matter emissions testing, outlined in Condition 7.1.b.vii., above.
(c) Each test run must be of sufficient duration and volume to collect a representative amount of particulate matter. Refer to ODEQ Source Sampling Manual, Vol. 1, 2015, Section 2.7.

c. The relative accuracy test audit (RATA) for the NO_x and CO CEMS will be used as the annual performance test for nitrogen oxides and carbon monoxide. Ammonia slip must be measured during the RATA, utilizing test methods approved by DEQ. [40 CFR 60.4405]

d. The permittee must demonstrate compliance with vent stream flow rate requirements in:
i. Distillation Operations, 40 CFR Part 60, Subpart NNN in accordance with Conditions 3.6.b. through 3.6.d.
ii. Using Method 2, 2A, 2C or 2D as appropriate for determination of the volumetric flow rate.

e. The permittee must demonstrate compliance with vent stream flow rate requirements in:
i. Reactor Operations, 40 CFR Part 60, Subpart RRR in accordance with Conditions 3.7.b through 3.7.d.
ii. Using Method 2, 2A, 2C or 2D as appropriate for determination of the volumetric flow rate.

f. All tests must be conducted in accordance with DEQ's Source Sampling Manual and the approved source test plan. The source test plan must be submitted at least 30 days in advance and approved by the Regional Source Test Coordinator. The source test report must be submitted to the Regional Source Test Coordinator within 60 days of the test unless otherwise approved in the source test plan.

Tested Pollutant	Reference Test Method*
PM	EPA Method 5 DEQ Method 5

Tested Pollutant	Reference Test Method*
NO_X	EPA Method 7E
CO	EPA Method 10
VOC	EPA Method 18, 25A or 320
Opacity	EPA Method 9

*Substitution of alternative test methods must be pre-approved by the DEQ.

g. Only regular operating staff may adjust the combustion system or production processes and emission control parameters during the source test and within two hours prior to the source test. Any operating adjustments made during the source test, which are a result of consultation with source testing personnel, equipment vendors or consultants, may render the source test invalid.

8.0 SPECIAL CONDITIONS

8.1. Initial Startup Notice

The permittee must notify DEQ in writing of the date a newly permitted source is first brought into normal operation. The notification must be submitted no later than seven (7) days after the initial startup. [OAR 340-214-0110]

8.2. Best Management Practices Plan

The permittee must prepare and implement a site-specific best management practices plan to minimize fugitive particulate and visible emissions. The plan must be submitted to the Department prior to the facility receiving biomass. The plan is to be submitted in a loose leaf binder. Unless otherwise stated, the Department will review for completeness within 30 days of receipt. The plan must be fully implemented in accordance with this permit condition. A current copy of the plan must be maintained at the facility and made available to operation and maintenance personnel. The plan shall identify reasonable measures to prevent particulate matter from becoming airborne. Such reasonable measures must include, but are not limited to the following:

a. Monitoring and compliance with Conditions 2.3.b. and 6.3.a. of this permit;
b. Management and operation procedures for ensuring that all access doors and openings to the biomass building are kept closed when not in use;
c. Management and operation procedures for ensuring access points to the biochar handling process and conveyor system to ensure fugitive biochar emissions are minimized at all times;
d. Management and operation procedures for ensuring that the biomass and biochar conveyor systems are being, operated and maintained in a manner that minimizes fugitive emissions;
e. Routine inspections and periodic sweeping or cleaning of paved roads and other areas as necessary to prevent migration of materials offsite; and

f. Annual review and update of the best management practices plan. All updates and modifications must be retained on site and submitted to DEQ upon request.

8.3. Control of Startup, Shutdown and Upset Gases

Within 60 days of achieving the maximum production rate, but no later than 180 days after initial startup the permittee must have the capability to combust all start-up, shut down and upset process gas emissions in a flare that meets the requirements of 40 CFR 60.18.

8.4. Complaints

Permittee must provide the Regional Office of DEQ with written notification within five days of all nuisance complaints received by the permittee during the operation of the facility. Documentation must include date of contact, time of observed nuisance conditions, description of nuisance condition, location of receptor, and status of plant operation during the observed period in accordance with Condition 2.6.

9.0 RECORDKEEPING REQUIREMENTS

9.1. Operation and Maintenance

The permittee must maintain the following records related to the operation and maintenance of the facility and associated air contaminant control devices: [OAR 340-214-0114]

a. All process and production records as required in Condition 15.0;
b. Monthly calculated criteria and GHG pollutant emissions in accordance with Condition 6.8;
c. Daily baghouse and vent filter pressure drop readings;
d. Monitoring and corrective actions on fugitive emissions;
e. Control efficiency specifications of all fabric filter bag replacement orders;
f. All excursions of the parametric action levels and the corrective action taken to return the control device to highest and best practicable treatment and control;
g. Daily carbon canister pressure differential readings during product load-out;
h. Inspection and repair activities;
i. Weekly inspections and measurements of natural gas at the flare pilot ensuring good combustion practices;
j. Records of maintenance performed on air pollution control equipment;
k. The monthly hours of operation for the front-end loaders and the fire pump engine;
l. The permittee must record and maintain records of the amount of combusted natural gas:
    i. Hourly natural gas usages for the gas turbine and duct burner (EU33) and recycle heater (EU34) in accordance with Condition 6.1.a.; and
    ii. Monthly natural gas usages for the reactor charge heater (EU39), the fractionator heater (EU40) and all other natural gas combusting equipment.
m. NSPS Subpart Kb – Storage Vessel Reporting and Recordkeeping Requirements. [40 CFR 60.115b]

i. Keep a record of each inspection of the naphtha product and off spec tanks. The record must identify the storage vessel on which the inspection was performed and must contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof and fittings);

ii. If any deficiencies are detected during the annual visual inspection required in Condition 3.4.b.i., a report is to be furnished to the Department within 30 days of the inspection. Each report must identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of, and the date the repair was made;

iii. After each inspection that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other listed control equipment defects, a report is to be furnished to the Department within 30 days of the inspection. The report must identify the storage vessel and the reason it did not meet the specifications, and list each repair made;

iv. The permittee must keep readily accessible records showing the dimensions of the storage tanks and an analysis showing the capacity of the storage tanks. [40 CFR 60.116b(b)] These records must be kept for the life of the source; [40 CFR 60.116b(a)]

v. The permittee must maintain records of the volatile organic liquids stored, the period of storage, and the maximum true vapor pressure of the stored liquids during the respective storage period. These records must be kept for at least 2 years; [40 CFR 60.116b(c)]

vi. The permittee must notify the Department within 30 days when the maximum true vapor pressure of the liquid stored in the tanks exceeds 5.2 kPa (0.754 psia). These records must be kept for at least 2 years. [40 CFR 60.116b(d)]

n. NSPS Subpart VVa – Equipment Leaks of VOC

i. For each monitoring event the permittee must record the monitoring instrument identification, operator identification, equipment identification, date of monitoring, and instrument reading; [40 CFR 60.486a(a)(3)]

ii. When each leak is detected, the permittee must attach a weatherproof and readily visible identification tag to the leaking equipment. The tag must be marked with the equipment identification number. The tag on a leaking valve may be removed after it has been monitored for 2 successive months as specified in Condition 3.5.g.iv and no leak has been detected during those 2 months. The tag on a connector may be removed after it has been monitored as specified in Condition 3.5.k.vi and no leak has been detected during that monitoring. The tag on all other leaking equipment may be removed after it has been repaired; [40 CFR 60.486a(b)]

iii. When each leak is detected, the following information must be recorded in a log and kept for 2 years in a readily accessible location:

(a) Instrument and operator identification numbers and the equipment identification number, except when indications of liquid dripping from a pump are designated as a leak;

(b) The date the leak was detected and the dates of each attempt to repair the leak;

(c) Repair methods applied in each attempt to repair the leak;

(d) Maximum instrument reading at the time the leak is successfully repaired or determined to be non-repairable, except when a pump is repaired by eliminating the indications of liquid dripping;
(e) "Repair delayed" and reason for the delay if the leak is not repaired within 15 calendar days after discovery of the leak;
(f) The signature of the owner or operator whose decision it was that repair could not be effected without a process shutdown;
(g) The expected date of successful repair if the leak is not repaired within 15 days;
(h) Dates of process unit shutdowns that occur while the equipment is unrepaired; and
(i) Date of successful repair of the leak. [40 CFR 60.486a(c)]

iv. The permittee must maintain the following information pertaining to all equipment subject to Condition 3.5 in a log that is kept in a readily accessible location:
(a) A list of identification numbers for equipment subject to Condition 3.5.
(b) A list of identification numbers for equipment that are designated for no detectible emissions under 40 CFR 60.482-2a(e), 60 482-3a(i), or 60.482-7a(f). The designation must be signed by the permittee;
(c) A list of equipment identification numbers for pressure relief valves required to comply with Condition 3.5.d;
(d) The dates, background level, and maximum instrument reading of each compliance test as required in 40 CFR 60.482-2a(e), 60.482-3a(i), 60 482-4a, and 60.482-7a(f);
(e) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service;
(f) Records of monitoring instrument calibrations including date of calibration, initials of operator performing the calibration, calibration gas cylinder identification, certification date, certified concentration, instrument scale(s) used, description of any corrective action taken if the meter readout could not be adjusted to correspond with the calibration gas values, results of each calibration drift assessment, and description of procedures used if the permittee makes its own calibration gas;
(g) The connector monitoring schedule for each process unit as specified in Condition 3.5.k.vii; and
(h) Records of each release from a pressure relief valve subject to Condition 3.5.d.

v. The following information for all valves subject to 40 CFR 60.482-7a(g) and (h), all pumps subject to 40 CFR 60.482-2a(g), and all connectors subject to 40 CFR 60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:
(a) A list of identification numbers for valves, pumps and connectors that are designated as unsafe to monitor, an explanation for each valve, pump and connector stating why it is unsafe to monitor, and the plan for monitoring each valve, pump or connector;
(b) A list of identification numbers for valves that are designated as difficult to monitor, an explanation of why the valve is difficult to monitor, and the schedule for monitoring each valve.

o. For distillation operations subject to NSPS Subpart NNN - Reporting and Recordkeeping Requirements under §60.665, the permittee must keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.008 scm/min (0.3 scf/min) and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new stream flow rate. [40CFR60.665(i)]

p. For reactor processes subject to NSPS Subpart RRR - Reporting and Recordkeeping Requirements under §60.705, the permittee must keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.008 scm/min (0.3 scf/min) and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new stream flow rate. [40CFR60.705(h)]

q. For the emergency fire pump subject to NSPS Subpart IIII- The permittee must maintain records of the operation of the engine in emergency and non-emergency service by recording with a non-resettable hour meter. The permittee must record the maintenance performed on the engine is accordance with Condition 4.2.d. [40 CFR 63.6640(f)]

9.2. Excess Emissions

a. The permittee must maintain the records of excess emissions listed below and as defined in OAR 340-214-0300 through 340-214-0340, recorded on occurrence. Typically, excess emissions are caused by process upsets, startups, shutdowns or scheduled maintenance. In many cases, excess emissions are evident when visible emissions are greater than 20% opacity as a six-minute block average.
   i. The date and time of the beginning of the excess emissions event and the duration or best estimate of the time until return to normal operation;
   ii. The date and time the permittee notified DEQ of the event;
   iii. The equipment involved;
   iv. Whether the event occurred during planned startup, planned shutdown, scheduled maintenance, or as a result of a breakdown, malfunction or emergency;
   v. Steps taken to mitigate emissions and corrective action taken, including whether the approved procedures for a planned startup, shutdown or maintenance activity were followed;
   vi. The magnitude and duration of each occurrence of excess emissions during the course of an event and the increase over normal rates or concentrations as determined by continuous monitoring or best estimate (supported by operating data and calculations); and
   vii. The final resolution of the cause of the excess emissions.

b. If there is an ongoing excess emission caused by an upset or breakdown, the permittee must immediately take action to minimize emissions by reducing or ceasing operation of the equipment or facility, unless doing so could result in physical damage to the equipment or facility, or cause injury to employees. In no case may the permittee operate after the beginning of the excess emissions, unless continued operation is approved by DEQ in accordance with OAR 340-214-0330(4).

c. In the event of any excess emissions which are of a nature that could endanger public health and occur during non-business hours, weekends or holidays, the permittee must immediately notify DEQ by calling the Oregon Emergency Response System (OERS). The current number is 1-800-452-0311.

d. The permittee must maintain a log of all excess emissions in accordance with OAR 340-

214-0340(3).

9.3. Complaints

The permittee must maintain a log of all complaints received by the permittee in person, in writing, by telephone or through other means according to Condition 2.6. Documentation must include all information identified in Condition 2.6. [OAR 340-214-0114]

9.4. Retention of Records

Unless otherwise specified, the permittee must retain all records for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application and make them available to DEQ upon request. The permittee must maintain the two (2) most recent years of records onsite. [OAR 340-214-0114]

10.0 REPORTING REQUIREMENTS

10.1. Excess Emissions

a. The permittee must notify DEQ of excess emissions events if the excess emission is of a nature that could endanger public health.
b. The permittee must also submit follow-up reports summarizing records of excess emissions as required in Condition 9.2 when required by DEQ. Such notice must be provided as soon as possible, but never more than one hour after becoming aware of the problem. Notice must be made to the regional office identified in Condition 12.0 by email, telephone, facsimile or in person.

10.2. Annual Report

For each year this permit is in effect, the permittee must submit to DEQ by **February 15** two (2) paper copies and one (1) electronic copy of the following information for the previous calendar year. If February 15 falls on a weekend or Monday holiday, the permittee must submit their annual report on the next business day.

a. Monthly and annual operating parameters:
   i. Number and duration of each process gas startup, shut down and malfunction;
   ii. Hours and fuel usage (MMscf) for gas turbine operations;
   iii. Hours and fuel usage (MMscf) for recycle heater operations;
   iv. Fuel usage (MMscf) and (MMBtu/hr) for reactor heater and the fractionator heater;
   v. Facility wide natural gas usage (MMscf);
   vi. Tons of biomass received and stored;
   vii. Tons of biomass processed;

viii. Tons of biochar produced;
ix. Hours of front-end loader operations;
x. Hours of the fire pump engine operations;
xi. Jet fuel produced (Mgal);
xii. Diesel fuel produced (Mgal); and
xiii. Naphtha produced (Mgal).

b. Calculations of annual pollutant emissions determined each month in accordance with Condition 6.9.
c. Calculations of annual GHG emissions determined each month in accordance with Condition 10.3.
d. A brief summary listing the date, time and the affected device/process for each excess emission that occurred during the reporting period.
e. Summary of complaints relating to air quality received by permittee during the year in accordance with Condition 8.3.
f. List permanent changes made in facility process, production levels and pollution control equipment which affected air contaminant emissions.
g. List maintenance performed including equipment replacement, such as, baghouse bags, filter vent cartridges, carbon canisters on pollution control equipment.

10.3. Greenhouse Gas Registration and Reporting

a. If the calendar year greenhouse gas emissions (CO_2e) are ever greater than or equal to 2,756 tons (2,500 metric tons), the permittee must annually register and report its greenhouse gas emissions with DEQ in accordance with OAR 340 Division 215.
b. If the calendar year greenhouse gas emissions (CO_2e) are less than 2,756 tons (2,500 metric tons) for three consecutive years, the permittee may stop reporting greenhouse gas emissions but must retain all records used to calculate greenhouse gas emissions for the five years following the last year that they were required to report. The permittee must resume reporting its greenhouse gas emissions if the calendar year greenhouse gas emissions (CO_2e) are greater than or equal to 2,756 tons (2,500 metric tons) in any subsequent calendar year.

10.4. Other reporting requirements

a. The permittee must submit source test plans and source test reports in accordance with Condition 7.1.f.
b. The permittee must submit two copies of the semi-annual NSPS excess emissions reports to DEQ's Eastern Region. Reports must be prepared and submitted in accordance with 40 CFR 60.7(c) except that, consistent with 40 CFR 60.19(d), the submittal date for these reports has been changed so that they are due at the same time as the semi-annual compliance report required by Condition 10.2. The report must include a log of all planned and unplanned excess emissions and a monitoring system performance report in accordance with 40 CFR 60.7(c), 60.49b(i), 60.334(j)(iii) and 60.4380(b).
c. Notification of at least 60 days prior to any physical or operational change which may increase the emission rate of any air pollutant to which a standard applies in accordance with 40 CFR 60.7(a)(4).

10.5. Notice of Change of Ownership or Company Name

The permittee must notify DEQ in writing using a DEQ "Transfer Application" form within 60 days after the following:

a. Legal change of the name of the company as registered with the Corporations Division of the State of Oregon; or
b. Sale or exchange of the activity or facility.

10.6. Construction or Modification Notices

The permittee must notify DEQ in writing using a DEQ "Notice of Intent to Construct" form, or other permit application forms and obtain approval in accordance with OAR 340-210-0205 through 340-210-0250 before:

a. Constructing, installing or establishing a new stationary source that will cause an increase in any regulated pollutant emissions;
b. Making any physical change or change in operation of an existing stationary source that will cause an increase, on an hourly basis at full production, in any regulated pollutant emissions; or
c. Constructing or modifying any air pollution control equipment.

11.0 ADMINISTRATIVE REQUIREMENTS

11.1. Permit Renewal Application

The permittee must submit the completed application package for renewal of this permit **180 days prior to the expiration date**. Two (2) paper copies and one (1) electronic copy of the application must be submitted to the DEQ Permit Coordinator listed in Condition 12.2. [OAR 340-216-0040]

11.2. Permit Modifications

Application for a modification of this permit must be submitted at least 60 days prior to the source modification. When preparing an application, the applicant should also consider submitting the application 180 days prior to allow DEQ adequate time to process the application and issue a permit before it is needed. A special activity fee must be submitted with an application for the permit modification. The fees and two (2) copies of the application must be submitted to the DEQ Business Office.

11.3. Annual Compliance Fee

The permittee must pay the annual fees specified in OAR 340-216-8020, Table 2, Part 2 and 3 for a Standard ACDP by **December 1** of each year this permit is in effect. An invoice indicating the amount, as determined by DEQ regulations will be mailed prior to the above date. **Late fees in accordance with Part 5 of the table will be assessed as appropriate.**

11.4. Change of Ownership or Company Name Fee

The permittee must pay the non-technical permit modification fee specified in OAR 340-216-8020, Table 2, Part 4 with an application for changing the ownership or the name of the company.

11.5. Special Activity Fees

The permittee must pay the special activity fees specified in OAR 340-216-8020, Table 2, Part 4 with an application to modify the permit.

12.0 DEQ CONTACTS / ADDRESSES

12.1. Business Office

The permittee must submit payments for invoices, applications to modify the permit, and any other payments to DEQ's Business Office:

Oregon Dept. of Environmental Quality
Financial Services – Revenue Section
700 NE Multnomah St., Suite 600
Portland, OR 97232-4100

12.2. Permit Coordinator

The permittee must submit all notices and applications that do not include payment to the Permit Coordinator.

Oregon Dept. of Environmental Quality
Eastern Region – Bend Office
Air Quality Permit Coordinator
475 NE Bellevue Dr., Suite 110
Bend, OR 97701-7415
eraqpermits@deq.state.or.us

12.3. Report Submittals

Unless otherwise notified, the permittee must submit all reports (annual reports, source test plans and reports, etc.) to DEQ's Eastern Region. If you know the name of the Air Quality staff member responsible for your permit, please include it:

Oregon Dept. of Environmental Quality
Eastern Region
475 NE Bellevue Dr., Suite 110
Bend, OR 97701-7415

12.4. Website

Information about air quality permits and DEQ's regulations may be obtained from the DEQ web page at www.oregon.gov/deq/.

13.0 GENERAL CONDITIONS AND DISCLAIMERS

13.1. Permitted Activities

a. Until this permit expires or is modified or revoked, the permittee is allowed to discharge air contaminants from the following:
   i. Processes and activities directly related to or associated with the devices/processes listed in Condition 1.0 of this permit;
   i. Any categorically insignificant activities, as defined in OAR 340-200-0020, at the source; and
   ii. Construction or modification changes that are Type 1 or Type 2 changes under OAR 340-210-0225 that are approved by DEQ in accordance with OAR 340-210-0215 through 0250, if the permittee complies with all of the conditions of DEQ's approval to construct and all of the conditions of this permit.
b. Discharge of air contaminants from any other equipment or activity not identified herein is not authorized by this permit.

13.2. Other Regulations

In addition to the specific requirements listed in this permit, the permittee must comply with all other applicable legal requirements enforceable by DEQ.

13.3. Conflicting Conditions

In any instance in which there is an apparent conflict relative to conditions in this permit, the most stringent conditions apply. [OAR 340-200-0010]

13.4. Masking of Emissions

The permittee must not cause or permit the installation of any device or use any means designed to mask the emissions of an air contaminant that causes or is likely to cause detriment to health, safety, or welfare of any person or otherwise violate any other regulation or requirement. [OAR 340-208-0400]

13.5. DEQ Access

The permittee must allow DEQ's representatives access to the plant site and pertinent records at all reasonable times for the purposes of performing inspections, surveys, collecting samples, obtaining data, reviewing and copying air contaminant emissions discharge records and conducting all necessary functions related to this permit in accordance with ORS 468.095.

13.6. Permit Availability

The permittee must have a copy of the permit available at the facility at all times. [OAR 340-216-0020(3)]

13.7. Open Burning

The permittee may not conduct any open burning except as allowed by OAR 340, division 264.

13.8. Asbestos

The permittee must comply with the asbestos abatement requirements in OAR 340, division 248 for all activities involving asbestos-containing materials, including, but not limited to, demolition, renovation, repair, construction, and maintenance.

13.9. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations.

13.10. Permit Expiration

a. A source may not be operated after the expiration date of the permit, unless any of the following occur prior to the expiration date of the permit: [OAR 340-216-0082]
   i. A timely and complete application for renewal of this permit or for a different ACDP has been submitted; or
   ii. A timely and complete application for renewal or for an Oregon Title V Operating Permit has been submitted, or
   iii. Another type of permit (ACDP or Oregon Title V Operating Permit) has been issued authorizing operation of the source.

b. For a source operating under an ACDP or Oregon Title V Operating Permit, a requirement established in an earlier ACDP remains in effect notwithstanding expiration of the ACDP, unless the provision expires by its terms or unless the provision is modified or terminated according to the procedures used to establish the requirement initially.

13.11. Permit Termination, Revocation, or Modification

DEQ may terminate, revoke, or modify this permit pursuant to OAR chapter 340 division 216. [OAR 340-216-0082].

14.0 EMISSION FACTORS

Emissions Device or Activity	Pollutant	Emission Factor (EF)	EF Units	EF Reference
Biomass Received & Stored	PM	1.14E-02	lb/ton	Manufacturer EPA-450/1-89-003
	PM_{10}	5.85E-03	lb/ton	
	$PM_{2.5}$	5.85E-03	lb/ton	
Biomass Processed	PM	1.20E-02	lb/ton	Manufacturer, AP-42 Section 13.2.4, AP-42 Section 13.2.1, and Tier 4 – 250 Hp Engine. Specifications
	PM_{10}	4.30E-03	lb/ton	
	$PM_{2.5}$	4.30E-03	lb/ton	
Biochar Produced	PM	7.14E-05	lb/ton	Manufacturer
	PM_{10}	7.14E-05	lb/ton	
	$PM_{2.5}$	7.14E-05	lb/ton	
Facility Wide Natural Gas (NG) Combustion	PM	8.34	lb/MMscft	AP-42 Section 1.4, AP-42 Section 1.6, and AP-42 Section 3.3
	PM_{10}	8.34	lb/MMscft	
	$PM_{2.5}$	6.01	lb/MMscft	
Gasifier Flare	SO_2	10	lb/hr	AP-42 Section 1.6
	NO_x	27.2	lb/hr	AP-42 Section 13.5
	CO	124	lb/hr	
	VOC	56	lb/hr	
Gas Turbine & Recycle Heater at SCR	SO_2	0.6	lb/MMscf	AP-42 Section 1.4
	VOC	5.5	lb/MMscf	AP-42 Section 1.4
Pilot Flare	SO_2	0.6	lb/MMscf	AP-42 Section 1.4
	NO_x	100	lb/MMscf	
	CO	84	lb/MMscf	
	VOC	5.5	lb/MMscf	
Reactor Charge Heater	SO_2	0.6	lb/MMscf	AP-42 Section 1.4
	NO_x	75	lb/MMscf	Vendor Data
	CO	0.31	lb/MMBtu	AP-42 Section 13.5
	VOC	5.5	lb/MMscf	AP-42 Section 1.4
Fractionator Feed Heater	SO_2	0.6	lb/MMscf	AP-42 Section 1.4
	NO_x	75	lb/MMscf	Vendor Data
	CO	0.31	lb/MMBtu	AP-42 Section 13.5
	VOC	5.5	lb/MMscf	AP-42 Section 1.4

Emissions Device or Activity	Pollutant	Emission Factor (EF)	EF Units	EF Reference
Front End Loader #1	SO_2	1.11E-06	lb/hr	Tier 4 – 250 Hp Engine. Specifications
	NO_x	1.65E-01	lb/hr	
	CO	1.44	lb/hr	
	VOC	7.82E-02	lb/hr	
Front End Loader #2	SO_2	1.11E-06	lb/hr	Tier 4 – 250 Hp Engine. Specifications
	NO_x	1.65E-01	lb/hr	
	CO	1.44	lb/hr	
	VOC	7.82E-02	lb/hr	
Equipment Leaks NSPS Subpart VVa				
Valve – gas	VOC	0.0132	lb/hr/source	EPA-453/R-95-017 Table 2-1
Valve – light liquid		0.0089		
Pump seal – light liquid		0.044		
Compressor seals gas		0.503		
Pressure relief valves		0.229		
Connectors		0.004		
Open ended lines		0.0037		
Sampling connections		0.033		
Jet Fuel Tank	VOC	Use EPA TANKS software or AP-42 algorithm for 12-month emission calculation		
Jet Fuel Day Tank 1				
Jet Fuel Day Tank 2				
Diesel Tank				
Diesel Day Tank				
Naphtha Tank				
Off-Spec Tank				

15.0 PROCESS/PRODUCTION RECORDS

Emissions Device or Activity	Process or Production Parameter	Frequency
Biomass Received	Tons	Monthly/Annually
Biomass Processed	Tons	Monthly/Annually
Biochar Produced	Tons	Monthly/Annually
Gasifier Flare	Hours of Operation	Monthly/Annually
	Number of Startup/Shutdowns & Upsets	
Gas Turbine	Natural gas (MMscf)	Monthly/Annually
	Hours of Operation	
Recycle Heater	Natural gas (MMscf)	Monthly/Annually
	Hours of Operation	
Pilot Flare	Natural gas (MMscf)	Monthly/Annually
Reactor Charge Heater	Natural gas (MMscf) & (MMBtu)	Monthly/Annually
Fractionator Feed Heater	Natural gas (MMscf) & (MMBtu)	Monthly/Annually
Front End Loader #1	Hours of Operation	Monthly/Annually
Front End Loader #2	Hours of Operation	Monthly/Annually
Jet Fuel	Gallons Produced	Monthly/Annually
Diesel	Gallons Produced	Monthly/Annually
Naphtha	Gallons Produced	Monthly/Annually

16.0 ABBREVIATIONS, ACRONYMS AND DEFINITIONS

ACDP	Air Contaminant Discharge Permit
ASTM	American Society for Testing and Materials
AQMA	Air Quality Maintenance Area
calendar year	The 12-month period beginning January 1st and ending December 31st
CAO	Cleaner Air Oregon
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2e	Carbon Dioxide Equivalent
DEQ	Oregon Department of Environmental Quality
dscf	dry standard cubic foot
EPA	US Environmental Protection Agency
FCAA	Federal Clean Air Act
Gal	Gallon(s)
GHG	Greenhouse Gas
gr/dscf	grains per dry standard cubic foot
HAP	Hazardous Air Pollutant as defined by OAR 340-244-0040
I&M	Inspection and Maintenance
lb	Pound(s)
MMBtu	Million British thermal units
NA	Not Applicable
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
OAR	Oregon Administrative Rules
ORS	Oregon Revised Statutes
O&M	Operation and Maintenance
Pb	Lead
PCD	Pollution Control Device
PEMS	Predictive Emission Monitoring System
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns in size
$PM_{2.5}$	Particulate Matter less than 2.5 microns in size
ppm	parts per million
PSD	Prevention of Significant Deterioration
PSEL	Plant Site Emission Limit
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
scf	standard cubic foot
SER	Significant Emission Rate
SIC	Standard Industrial Code
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Special Control Area	as defined in OAR 340-204-0070
TACT	Typically Achievable Control Technology
VE	Visible Emissions
VOC	Volatile Organic Compound
year	A period consisting of any 12-consecutive calendar months

State of Oregon
Department of
Environmental
Quality

STANDARD AIR CONTAMINANT DISCHARGE PERMIT REVIEW REPORT

Red Rock Biofuels LLC
18281 Kadrmas Road
Lakeview, OR 97630

Source Information:

SIC	2869, 4911, 4961
NAICS	325194, 221112 221330

Source Categories (Table 1 Part, code)	Table 1, Part B,
Public Notice Category	III

Compliance and Emissions Monitoring Requirements:

FCE	No
Compliance schedule	No
Unassigned emissions	No
Emission credits	No
Special Conditions	Yes

Source test	60 to 180 days after Startup, annual RATA, & 1 yr prior to permit expiration
COMS	No
CEMS	Yes
PEMS	No
Ambient monitoring	No

Reporting Requirements

Annual report (due date)	Feb 15th
Semi-Annual report (due dates)	No

Monthly report (due dates)	No
Excess emissions report	Yes
Other (specify)	No

Air Programs

Synthetic Minor (SM)	No
SM -80	No
NSPS (list subparts)	A, Dc, Kb, VVa, NNN, RRR, IIII, KKKK
NESHAP (list subparts)	ZZZZ
CAO	No

NSR	No
PSD	No
GHG	Yes
RACT	No
TACT	Yes

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PERMITTING

PERMITTEE IDENTIFICATION

1. Red Rock Biofuels LLC, located at 18281 Kadrmas Road, Lakeview, OR 97630.

PERMITTING ACTION

2. The proposed permit includes a renewal and moderate technical modification of an existing Standard Air Contaminant Discharge Permit (ACDP) that was issued on 6/24/2015 and was originally scheduled to expire on 6/1/2020. The permittee is on a Standard ACDP due to the complexity of the source. The existing ACDP remains in effect until final action is been taken on the renewal application because the permittee submitted a timely and complete application for renewal. The facility has not been constructed or operated to date. An application for a moderate technical permit modification was submitted and received on 5/18/2020.

3. Red Rock Biofuels has been determined to be an existing source for the purposes of Cleaner Air Oregon in accordance with OAR 340-245-0020 because the air quality permit application was submitted and deemed complete, or construction had commenced on this facility prior to November 16, 2018. As an existing source the permittee is required to perform a risk assessment in accordance with OAR 340-245-0050, and demonstrate compliance with the Risk Action Levels for an “Existing Source” in OAR 340-245-8010 Table 1 when called in by DEQ. Red Rock Biofuels has not been called in and therefore, has not performed a risk assessment.

OTHER PERMITS

4. Other permits issued or required by the DEQ for this source includes a storm water GEN12C construction NPDES permit.

ATTAINMENT STATUS

5. Red Rock Biofuels LLC is to be located south of the Town of Lakeview which is considered an Oregon recognized maintenance area for PM_{10}. The source meets industrial requirements set forth in the maintenance plan and DEQ’s rules. Additionally, the source is located in an area that has exceeded US Environmental Protection Agency (EPA) standards for $PM_{2.5}$. However, Lakeview is not yet considered a US EPA designated nonattainment area for $PM_{2.5}$ and there are no special $PM_{2.5}$ rules at this time for new industrial sources to locate in Lakeview. In addition, the facility, as proposed, will not have significant emissions of $PM_{2.5}$. Air quality in Lakeview is considered unclassified by the US EPA for SO_2, NO_x, CO and ozone because DEQ is not monitoring for these pollutants in Lakeview. DEQ only conducts monitoring for a specific pollutant in areas that are considered to potentially have problems with air quality. DEQ is

responsible for establishing permit emissions limits that ensure air quality standards are not violated.

6. This source is not located within 10 kilometers (6.2 miles) of a Class I air quality protection area.

SOURCE DESCRIPTION

OVERVIEW

7. Red Rock Biofuels LLC (RRB), a subsidiary of Red Rock Biofuels Holdings, Inc,, was permitted on June 24, 2015 to construct a new biofuels facility and associated infrastructure to produce jet fuel, diesel fuel, and naphtha from a woody biomass feedstock consisting primarily of mill and forest residues or with natural gas as a feedstock. The facility will have the capability to use natural gas in combination with biomas or as the sole feedstock. Annually, the plant was permitted to gasify approximately 331,818 tons per year of biomass feedstock to produce approximately 7.2 million gallon (MMgal) of jet fuel, 7.2 MMgal of diesel fuel, and 3.6 MMgal of naphtha. There is no limit on the volume of natural gas that can be used as feedstock by itself or in combination with biomass. The facility will employ approximately 45 people and operate 24 hours per day. The facility will have the capability to produce the jet fuel, diesel fuel, and naphtha.

   After preparation in the biomass building, wood chips are to be conveyed to the gasification system where a steam-heated pyrolysis process is used to gasify the wood chips into a synthetic gas (syngas) product. When natural gas is used as the sole feedstock the wood handling and pyrolysis chamber, recycle loop, diesel scrubber, and biochar handling system would not be operated.

   The generated syngas product is to be processed through an amine scrubbing system to remove carbon dioxide impurities. The cleaned compressed syngas product is further processed in the Fischer-Tropsch (FT) reactor to produce FT wax and FT condensate. The produced FT wax and FT condensate is upgraded to final products in the hydro-processing and distillation processes. The hydro-treated product is separated into the final products in a fractionation column with a side stripper each for jet, diesel, and naphtha fuels. The Fischer-Tropsch reactor and pressure swing adsorption system processes are both entirely enclosed.

   The final fuel products (jet fuel, diesel fuel, and naphtha) are sent to a tank farm. Tanks for the jet fuel and diesel fuel services have fixed roof tanks for load out to either truck or railcar.

8. On February 25, 2020, DEQ issued a Type 2, Notice of Intent to Construct Approval (NC #31222) for the construction of a new 158 MMBtu/hr gas Solar SoLoNOx (Titan 130)

Turbine with duct firing and heat recovery steam generation (HRSG) and a recycle heater. The permittee modified their process to include an Air Separation Unit ("ASU") which increased the facility's electric power requirement needs beyond the local grid's availability. Thus, to meet the higher electric power requirements, RRB is installing the gas turbine with duct firing to generate steam. The steam will then be used by a steam turbine generator to produce the needed electrical power. The facility eliminated the construction the previously permitted auxiliary boiler and gasifier heater as the main source of process heat for the facility. The recycle heater will heat the pyrolysis chamber and preheat combustion air for the natural gas burners. Like the permitted auxiliary boiler and gasifier heater, the proposed gas turbine (with duct firing and HRSG) and recycle heater emissions will be combined and controlled by a Low NOx selective catalytic reduction (SCR).

9. On May 21, 2020, RRB, submitted a moderate technical permit modification to make modifications to the process in existing Standard Air Contaminant Discharge Permit for associated infrastructure to produce the jet, diesel, and naphtha fuels from a woody biomass feedstock and natural gas. Annually, the modified plant will have the potential to gasify approximately 438,000 wet tons per year of feedstock to produce approximately 13.6 MMgal of combined jet fuel and diesel fuel, as well as 3.5 MMgal naphtha. The total facility potential to emit is to remain below significant emission rates (SERs) and major source thresholds for all regulated pollutants.

Table 1: Modified Process Changes in Raw Materials Usage and Annual Fuel Production:

Materials	Current Permit	Proposed Permit	Units
Feedstock Processed	331,818	219,000	BDT/yr
Natural Gas Processed	undetermined	undetermined	MMscft/yr
Jet fuel manufactured	7.2	9.3	MMgal/yr
Diesel fuel manufactured	7.2	4.3	MMgal/yr
Naphtha manufactured	3.6	3.3	MMgal/yr

PROCESS AND CONTROL DEVICES

10. Existing and modified air contaminant processes at the facility consist of the following:

a. Raw biomass (wood chips) are to be delivered by trucks. The trucks are tipped to empty the raw biomass through the backend of the truck. Particulate emissions would be reduced by enclosing the backend of the truck with a hood that has a negative pressure system to pull dust into a baghouse as the truck is emptied. Once the truck is emptied, a lid on the receiving bin automatically closes to prevent particulate emissions from the bin. The biomass is to be conveyed by enclosed conveyors to storage. The biomass is to be chipped in preparation for further processing. The wood chips are then to be conveyed by enclosed conveyors stacker that deposits the wood chips onto an outdoor toroidal-shaped storage pile. To reduce particulate emission during stacking of the wood chips, the stacker has a telescoping neck that encloses the plume of wood chips as the wood chips are deposited. The telescoping neck extends or retracts to maintain a distance of approximately one-inch above the top of the pile. From the storage pile, wood chips are to be pushed by front-end loaders to the reclaimer and conveyed by enclosed conveyors to a shredder, which would reduce the wood chips to a size usable by the gasifier. Shredded feedstock are to be conveyed by enclosed conveyors to a surge bin which has bin vent filters to control emissions.

b. From the shredded feed surge bin, the shredded wood chips are fed into an enclosed pyrolysis reactor by enclosed screwfeeders. The conversion process begins by the recycle heater exhaust heating pyrolyzing reactor with the wood chips using hot stream of gases at 1200 °F. Pyrolysis of the wood chips produces three products: pyrolysis gas, liquids, and biochar.

c. Biochar, the solid product of pyrolysis, is removed from the pyrolysis reactor using a mechanical separation system. The biochar is transferred to a storage bin by a pneumatic system with a nitrogen flush system to cool and prevent the biochar from exposure to air and potential combustion. The storage bin would have bin vent filters and would be equipped with a hopper to allow for truck loading. The biochar is quenched with water prior to load out.

d. Pyrolysis gas and liquids (in aerosol form) leaving the pyrolysis reactor will pass through a scrubber column that uses renewable diesel to cool and condense the pyrolysis liquids. This diesel scrubber also knocks out solid particles entrained in the pyrolysis gas. A portion of the clean pyrolysis gas is then sent to the partial oxidation (POX) unit. The remaining clean pyrolysis gas is sent to the Recycle Heater where it is heated to 1200°F and sent back to the Pyrolysis Reactor to heat the incoming wood chips. The pyrolysis liquids and particles that accumulate at the bottom of the diesel scrubber are injected into the POX unit.

e. In the POX unit, oxygen is injected and reacts exothermically with the pyrolysis gas, liquids, and particles. The exothermic reaction increases the overall gas temperature, causing the long-chain hydrocarbon molecules to breakdown into synthetic gas (syngas) consisting mainly of carbon monoxide, hydrogen, and other short-chain hydrocarbon molecules. The syngas will travel from the POX unit to a sour gas shift reactor where steam is injected and reacts with the syngas to produce the correct hydrogen-to carbon monoxide ratio for the downstream Fischer-Tropsch synthesis process.

f. After the sour gas shift reactor, the hot syngas is to be cooled in a heat exchanger that creates steam for process heat. The syngas then passes through a water scrubber that removes hydrogen sulfide, particulates, and other water-soluble contaminants and further cools the syngas.

g. The clean syngas then continues to the amine CO_2 removal unit, syngas compression systems, and through a sulfur guard bed to remove any residual sulfur. During equipment start-up and periods of system upsets, syngas in the gasification system will be flared to control emissions of volatile organic compounds (VOCs).

h. The clean, compressed syngas next enters into two parallel Fischer-Tropsch (FT) synthesis trains where the syngas is converted to FT wax (long hydrocarbon chains), FT condensate (short hydrocarbon chains), water, and tail gas consisting of light hydrocarbons and unreacted feed. A portion of the tail gas is recycled to an autothermal reformer (ATR) where the light hydrocarbons are converted to syngas (CO and H2) which is then sent to the sour gas shift reactor. The remainder of the tail gas is sent to the fractionator feed heater or reactor charge heater burners as fuel or to flare.

i. Water produced by the FT reaction is sent to the water clean-up system. Both FT trains are entirely enclosed and, thus, no emissions are expected during normal operations. During equipment start-up and periods of system upsets, syngas produced in the process will be flared to control emissions of volatile organic compounds (VOCs).

j. From the FT synthesis process, the produced FT waxes and FT condensates are upgraded to the final products in the hydroprocessing phase. Wax enters the hydrocracking reactor followed by the fractionation column. Hydrogen for this process is generated by a pressure swing adsorption (PSA) process using a side stream of syngas removed prior to the FT system. The off-gas from both the PSA and hydrocracking systems is sent to and burned as fuel in either the fractionator feed heater or reactor charge heater during normal operation or to the flare under upset conditions. The hydrotreated product is separated into the final products in a fractionation column with a side stripper each for jet fuel, diesel fuel, and naphtha. This system is entirely enclosed; therefore, no emissions are expected during normal operations. RRB may blend some jet fuel into the diesel fuel to improve diesel fuel properties but blending will be determined later based on diesel fuel properties. During startup and upset conditions, emissions may be routed to the gasifier flare for control.

k. When natural gas to be used as the sole feedstock, the natural gas will be introduced into the system at the Auto Thermal Reformer (ATR) EU42 and the partial oxidation (POX) EU36 units. After being introduced at the ATR and POX, the natural gas will follow the same processes as the syngas to make product.

l. Product is sent to the tank farm containing day, off-spec, and final product tanks for the three products, for a total of seven tanks. The naphtha fuel tank and off-spec fuel tank have internal floating roofs.

m. Tanks in jet fuel and diesel fuel service are fixed roof tanks. Product meeting desired specifications is loaded out to either truck or rail car. Product load out emissions are controlled by carbon canisters to remove +99% VOC emissions. The capacity of each proposed tank is listed below.

n. The new 158 MMBtu/hr gas Solar SoLoNOx (Titan 130) turbine with a 87.8 MMBtu/hr duct burner and heat recovery steam generation (HRSG) will generate all electric power requirements for the facility operations.

o. Fugitive emissions include various emissions throughout the plant site that are uncollected and not vented. The processes include the following activities and processes font end loader and vehicle traffic on unpaved/paved roads.

Table 2: Product and Tank Capacities in the Existing Permit:

Tank ID	Product	Tank Capacity
TK01	Jet fuel day tank	30,000 gallons
TK02	Jet fuel final storage	300,000 gallons

Tank ID	Product	Tank Capacity
TK03	Jet fuel off-spec tank	30,000 gallons
TK04	Diesel fuel day tank	30,000 gallons
TK05	Diesel fuel final storage	300,000 gallons
TK06	Diesel fuel off-spec tank	30,000 gallons
TK07	Naphtha day tank	12,000 gallons
TK08	Naphtha final storage	120,000 gallons
TK09	Naphtha off-spec tank	12,000 gallons

Table 3: Product and Tank Capacities Proposed in Permit Modification:

Tank ID	Product	Tank Capacity
TK01	Jet Fuel Tank	300,000 gallons
TK02	Jet Fuel Day Tank 1	8,000 gallons
TK03	Jet Fuel Day Tank 2	8,000 gallons
TK04	Diesel Tank	300,000 gallons
TK06	Diesel Day Tank	15,000 gallons
TK07	Naphtha Tank	150,000 gallons
TK08	Off-spec Tank	50,000 gallons

Table 4: Emissions Points and Fugitive Source Emissions Included in the Proposed Permitting Action:

Unit Description	Emission Unit	Emission Point	Status	Pollution Control Devices	
				Description	PCD ID
Biomass Truck Receiving #1	EU01	EP13	Modified	Baghouse	CE10
Biomass Truck Receiving #2	EU02	EP21	Modified	Baghouse	CE15
Biomass Conveyor System	EU04	FS04	No Change	None	NA
Biomass Storage	EU05	FS05	No Change	None	NA
Biomass Handling	EU06	FS06	No Change	None	NA
Chipper Conveying	EU07	FS07	Removed	Water Spray	CE04
Biomass Chipper, Handling & Storage	EU08, EU09	EP01	Removed	Baghouse	CE05
Biomass Surge Bin	EU10	EP14	Modified	Vent Filters	CE11
Biomass Conveying and Shredder	EU03	EP14	Modified	Vent Filters	CE11
Gasifier Conveying	EU11	EP01	Removed	Baghouse	CE05
Gasifier System	EU12	None	Modified	Flare	CE07
Auxiliary Boiler	EU13	EP02	Removed	SCR	CE06
Gasifier Startup/Upset Flaring	EU14 EU15	EP03	Modified	Flare	CE07

Unit Description	Emission Unit	Emission Point	Status	Pollution Control Devices	
				Description	PCD ID
Gas Turbine W/ Duct Firing & HRSG	EU33	EP02	New	SCR	CE06
Recycle Heater	EU34	EP02	New	SCR	CE06
Diesel Scrubber	EU35	EP03	New	Flare	CE07
POX Unit	EU36	EP03	New	Flare	CE07
Water Scrubber	EU37	EP15	New	Scrubber	CE12
Sour Gas Shift	EU41	EP03	New	Flare	CE07
Oil Water Separator	EU38	None	New	None	NA
Amine CO_2 Removal	EU16	EP04	No Change	None	NA
FT Synthesis Process	EU17	EP03	New	Flare	CE07
Hydroprocessing and Distillation	EU18	EP03	Modified	Flare	CE07
Auto Thermal Reformer (ATR)	EU42	None	New	None	NA
Thermal Oil Heater	EU19	EP05	Removed	None	NA
Cooling Towers	EU20	EP06	No Change	None	NA
Emergency Engine Generator	EU21	EP07	Removed	None	NA
Emergency Fire Pump	EU22	EP08	No Change	None	NA
Reactor Charge Heater	EU39	EP17	New	None	NA
Fractionator Feed Heater	EU40	EP18	New	None	NA
Ash Separator	EU23	EP09	Removed	Baghouse	CE08
Ash Conveying to Biochar Handling and Conveying	EU24	EP03	Modified	Flare	CE07
Ash Storage changed to Biochar Silo	EU25	EP09	Modified	Vent Filter	CE08
Ash Load-out changed to Biochar Loadout	EU26	FS08	Modified	None	NA
Product Loadout - Truck	EU27	EP19	Modified	Carbon Canisters	CE13
Product Loadout - Rail	EU28	EP20	Modified		CE14
Product Load-out Flare and Pilot	EU29	EP10	Removed	Flare	CE09
Truck Traffic On-site	EU30	FS09	No Change	None	NA
Front End Loader #1	EU31	EP11	No Change	None	NA
Front End Loader #2	EU32	EP12	No Change	None	NA

CONTINUOUS MONITORING DEVICES

11. The facility has the following continuous monitoring devices:

Table 5: Emission Units with Continuous Monitoring Devices

Unit Description	Emission Unit	Emission Point	Description	Monitoring Device
Biomass Truck Receiving #1	EU01	EP13	Baghouse	Pressure Gage
Biomass Truck Receiving #2	EU02	EP21	Baghouse	Pressure Gage
Biomass Surge Bin	EU10	EP14	Vent Filters	Pressure Gage
Biomass Conveying and Shredder	EU03	EP14		
Gas Turbine W/ Duct Firing & HRSG	EU33	EP02	SCR	NO_x & CO CEMS
Recycle Heater	EU34	EP02		
Product Loadout - Truck	EU27	EP19	Carbon Canister	Pressure Gage
Product Loadout - Rail	EU28	EP20	Carbon Canister	Pressure Gage
Emergency Fire Pump	EU22	EP08	Hour meter	Non-resettable engine operation time meter

COMPLIANCE HISTORY

12. The facility will be inspected by DEQ personnel to ensure compliance with the permit conditions.

SPECIAL CONDITIONS

13. Permittee must notify DEQ in writing the date the new facility is started up as soon as practicable, but not more than seven (7) days after the facility starts operating.

14. Permittee must develop, install and maintain best management practices to minimize fugitive and visible dust emissions. Design measures include enclosed material handling processes with enclosed storage and air pollution equipment. The following best management practices are proposed at the RRB facility:

    a. The permittee must control and minimize fugitive emissions from receiving and handling raw biomass through approved work practices. If controls are not adequate and fugitive emissions occur at the facility, the permit includes a requirement for the permittee to submit a plan for controlling the fugitive emissions.

Once approved by DEQ, the plan must be implemented by the permittee. Additional measures for controlling fugitive emissions may include installing additional enclosures or partial enclosures where raw biomass materials are handled.

b. Permittee must manage all access points to the biomass buildings and enclosed conveyor systems to ensure fugitive emissions are minimized at all times.

c. The permittee must capture and control all natural gas exhaust from the recycle heater and turbine with a properly functioning selective catalytic reduction unit that reduces the nitrogen oxide emissions prior to discharging to the atmosphere.

d. Permittee must control and manage all syngas product during start-up and system upset conditions with a properly operated and functioning open flare. The flare will be equipped with a pilot flare detection system. The open flare is to fully combust all syngas product prior to being emitted to the atmosphere.

e. Permittee must manage all access points to the biochar handling process and conveyor system to ensure fugitive biochar emissions are minimized at all times. All biochar emissions originating from the conveyor system, bins and hoppers must exit though a properly functioning vent filter.

f. Permittee must control and manage all vapors generated during product load-out with properly operated and functioning carbon canisters.

15. Permittee must provide the Regional Office of DEQ with written notification within five days of all nuisance complaints received by the permittee during the operation of the facility. Documentation must include date of contact, time of observed nuisance conditions, description of nuisance condition, location of receptor, and status of plant operation during the observed period.

EMISSIONS

16. Proposed Plant Site Emissions Limits information.

Table 6. Plant Site Emission Limits (PSEL)

Pollutant	Baseline Emission Rate (tons/yr)	Netting Basis		Plant Site Emission Limits (PSEL)		
		Previous (tons/yr)	Proposed (tons/yr)	Previous PSEL (tons/yr)	Proposed PSEL (tons/yr)	PSEL Increase (tons/yr)
PM	0	0	0	24	24	0
PM_{10}	0	0	0	14	14	0
$PM_{2.5}$	NA	0	0	9	9	0
SO_2	0	0	0	39	39	0
NO_x	0	0	0	39	39	0
CO	0	0	0	99	99	0
VOC	0	0	0	39	39	0
GHG (CO_2e)	0	0	0	272,719	226,136	-46,583

a. The baseline emission rate was established in previous permitting actions and there is no new information that effects the previous determination.
b. For Standard ACDPs, the netting basis is equal to the baseline emission rate minus emission reductions required by rule plus emission increases approved in accordance with OAR 340, division 224 (NSR rules). [OAR 340-222-0046.]
c. The previous PSEL is the PSEL in the last permit.
d. The proposed PSELs for all criteria pollutants are equal to the Generic PSELs in accordance with OAR 340-222-0041(1). The basis for using generic PSELs is provided in the Emission Detail Sheets at the end of this Review Report.
e. The PSEL is a federally enforceable limit on the potential to emit.
f. The GHG baseline emission rate and Netting Basis are zero "0" since the facility did not exist and operate during the 2000-2010 GHG baseline period.

SIGNIFICANT EMISSION RATE ANALYSIS

17. For each pollutant, the proposed Plant Site Emission Limit is less than the sum of the Netting Basis and the significant emission rate, thus no further air quality analysis is required at this time.

TITLE V MAJOR SOURCE APPLICABILITY

18. A major source is a facility that has the potential to emit 100 tons/year or more of any criteria pollutant or 10 tons/year or more of any single HAP or 25 tons/year or more of combined HAPs. This facility is not a major source of emissions. The basis for this determination can be found in paragraph 16 for all criteria pollutants and paragraph 24 below for HAP emissions. The basis for the criterial pollutant and HAP emission calculations are located in the Emissions Detail Sheets of this Review Report.

19. A source that has potential to emit at the major source levels but accepts a PSEL below major source levels is called a Synthetic Minor (SM). This source does not have the potential to emit at major source levels. Therefore, this source is not a Synthetic Minor, with respect to federal new source review. The basis for this determination can be found in the emission calculations located in the Emissions Detail Sheets of this Review Report.

20. A source that has the potential to emit at or above 80% of Title V major source thresholds is called a Synthetic Minor 80 (SM-80). The source does not have the potential to emit at major source levels nor does it have actual emission of at least 80% of the major source level. The basis for this determination can be found in the emission calculations located in the Emissions Detail Sheets of this Review Report.

21. A source that has the potential to emit less than major source thresholds is called a True Minor. This source is a True Minor. The basis for this determination can be found in the Emissions Detail Sheets of this Review Report.

22. A source that has the potential to emit less than major source thresholds but is required by rule to obtain a Title V permit is called a Title V minor source. This source is not a Title V minor source based on no sources at this facility are required by rule to obtain a Title V operating permit.

CRITERIA POLLUTANTS

23. This facility is a True Minor source of criteria pollutant emissions.

HAZARDOUS AIR POLLUTANTS

24. This source is not a major source of hazardous air pollutants. The basis for this determination can be found in the Emissions Detail Sheets of this Review Report.

Table 7. Potential to Emit Hazardous Air Pollutants:

Hazardous Air Pollutants	Potential to Emit (pounds/year)	Potential to Emit (tons/year)
Benzene	1,120	5.60E-01
Ethylbenzene	1,250	6.25E-01
Formaldehyde	302	1.51E-01
Hexane	10,575	5.29
Naphthalene	663	3.32E-01
Toluene	3,627	1.81
Xylene	6,239	3.12
Sum of Highest Emitting HAPs	**23,777**	**11.89**
Sum of Other HAPs	**616**	**0.31**
Total HAP emissions	**24,393**	**12.20**

CLEANER AIR OREGON

25. The Cleaner Air Oregon Toxic Air Contaminant emissions inventory for this source has not been submitted because the facility is currently under construction and has not operated.

26. RRB has not been called in and therefore, has not performed a risk assessment.

TOXICS RELEASE INVENTORY

27. The Toxics Release Inventory (TRI) is federal program, administered by the EPA, that tracks the management of certain toxic chemicals that may pose a threat to human health

and the environment, over which DEQ has no regulatory authority. It is a resource for learning about toxic chemical releases and pollution prevention activities reported by certain industrial facilities. Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA) created the TRI Program. In general, chemicals covered by the TRI Program are those that cause:

a. Cancer or other chronic human health effects;
b. Significant adverse acute human health effects; or
c. Significant adverse environmental effects.

28. There are currently over 650 chemicals covered by the TRI Program. Facilities that manufacture, process or otherwise use these chemicals in amounts above established levels must submit annual TRI reports on each chemical.

29. RRB is not currently covered by the TRI program because the facility has not been operating or fully constructed.

ADDITIONAL REQUIREMENTS

NEW SOURCE PERFORMANCE STANDARDS APPLICABILITY

30. 40 CFR Part 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, and commenced construction after 2/18/2005, is applicable to the Solar SoLoNOx Titan 130, natural gas combustion turbine. Applicable requirements and emission standards are included in the permit. The combined cycle combustion turbine emissions will be controlled with a Low NOx selective catalytic reduction (SCR) monitored with CEMS.

Table 8: 40 CFR Part 60, Subpart KKKK New Source Performance Standards:

Turbine	40 CFR Part 60 Citation	Pollutant	Limit	Compliance Monitoring
Gas Turbine W/ Duct Firing & HRSG	40 CFR 60.4320(a)	NO_x	25 ppm @ 15% O_2 or 1.2 lb/MWh	30- day rolling average using CEMS data
	40 CFR 60.4330(a)(2)	SO_2	0.060 lb/MMBtu heat input	Pipeline quality natural gas will comply with this limit*

*If the gaseous fuel is demonstrated to meet the definition of natural gas in 60.331(u) the permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine.

31. Accidental Release Program (40 CFR Part 68): Anhydrous ammonia is stored onsite for use in the SCR system for NOx control. A risk management plan is required.

32. 40 CFR Part 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels for which construction, reconstruction or modification commenced after

7/23/84 - is applicable to the Naphtha product tank (TK07) and the Off-spec tank (TK08) because they are greater than 151 m^3 and 75 m^3, respectively, and hold liquids with a true vapor pressure greater than 3.5 kPa.

33. 40 CFR Part 60, Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for construction that commences after 11/7/2006- is applicable to all affected process equipment. Applicable requirements are included in the permit.

34. 40 CFR Part 60, Subparts NNN – Standards of Performance for VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Distillation Operations is applicable for distillation systems for which construction, reconstruction or modification commenced after 12/30/1983. Affected facilities include each distillation unit and the recovery system into which their vent streams are discharged; or each combination of two or more distillation units and the common recovery system into which their vent streams are discharged. Applicable requirements are included in the permit.

35. 40 CFR Part 60, Subpart RRR – Standards of Performance for VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Reactor Processes, Operations is applicable for reactor processes for which construction, reconstruction or modification commenced after 6/29/1990. The vent stream from an affected pyrolysis/gasifier reactor and FT reactor units are routed to a distillation unit subject to Subpart NNN and has no other release to the air except for a pressure relief valve. Therefore, the facility is exempt from all provisions of this subpart except for the reporting and recordkeeping requirements set forth in 60.705(r). The applicable requirements are included in the permit.

36. 40 CFR Part 60, Subpart IIII – Standards of Performance for Stationary Compressions Ignition Internal Combustion Engines is applicable to the Clark 345Hp, Tier 3 emission certified, Model JW6H-UFAD70 emergency fire pump engine. Applicable requirements are included in the permit.

37. 40 CFR Part 60, Subpart XX - "Standards of Performance for Bulk Gasoline Terminals," is not applicable to the proposed source because the facility will not be in the gasoline service and will therefore not function as an affected facility regulated by this federal standard.

38. 40 CFR Part 60, Subpart OOOO - "Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution," is not applicable to the proposed source because the facility will not perform crude oil and natural gas production, transmission or distribution operations, and will therefore not function as an affected facility regulated by this federal standard.

SUMMARY OF NEW SOURCE PERFORMANCE STANDARDS

39. A summary of the Subpart KKKK requirements and their applicability to the combustion turbines is provided below:

Table 9: 40 CFR Part 60, Subpart KKKK New Source Performance Standards Applicability:

Subpart KKKK Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.4305(a)	Applicability	Yes	The combustion turbine will have been constructed after February 18, 2005 making it subject to Subpart KKKK.
60.4305(b)	Subpart Db and GG exemption	Yes	
60.4315	Regulated pollutants (NO_x and SO_2)	Yes	
60.4320(a)	NO_x emission limits	Yes	The limits in Table 1 for new turbines firing natural gas, greater than 50 MMBtu/h and equal or less than 850 MMBtu/h heat input apply to this combustion turbine.
60/4320(b)	Provisions for two or more turbines serving a single generator	No	Only one turbine.
60.4325	Emission limits for multiple fuels	No	Only natural gas is burned in the turbine.
60.4330(a)(1)	SO_2 emission limit based on power output	No	The compliance limit will be based on heat input.
60.4330(a)(2)	SO_2 emission limit based on heat input	Yes	The limit is 0.060 lb SO_2/MMBtu heat input.
60.4330(b)	Limits for non-continental areas	No	The facility is not located in the specified area.
60.4333(a)	Good air pollution control practices	Yes	
60.4333(b)	Provisions for common steam header for more than one combustion turbine	No	There is only one combustion turbine.
60.4335	Compliance provisions for water or steam injection systems	No	Water or steam injection is not used to control NO_x emissions from the combustion turbine.
60.4340(a)	Performance testing for demonstrating compliance with the emissions limits	No	A CEMS will be used for monitoring compliance instead of annual performance tests.
60.4340(b)(1)	CEMS	Yes	
60.4340(b)(2)	Continuous parameter monitoring	No	A CEMS will be used for monitoring compliance instead of a continuous parameter monitoring system.
60.4345	CEMS requirements	Yes	
60.4350	CEMS excess emissions	Yes	Provisions for combined cycle are applicable. [60.4350(f)(2)]
60.4355	Parameter monitoring plan	No	A CEMS will be used for monitoring compliance instead of a continuous parameter monitoring system.
60.4360	Total fuel sulfur monitoring	No	Will comply with 60.4365(a) instead.
60.4365(a)	Tariff	Yes	
60.4365(b)	Representative fuel sampling data	No	Will use tariff.

Subpart KKKK Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.4370	Frequency of fuel sulfur content monitoring	No	Will use tariff.
60.4375(a)	Reports for parameter monitoring and annual performance tests	No	Will be monitoring compliance with a CEMS.
60.4380(a)	Excess emissions reports when using water or steam injection	No	Water or steam injection is not used to control NO_x emissions.
60.4380(b)	CEMS excess emission reports	Yes	Defines excess emissions, monitoring downtime, and clarifies that excess emissions are based on the highest emissions standard if there are multiple emissions standards (e.g., ppm and lb/MWh).
60.4380(c)	Excess emissions reports for parameter monitoring	No	Will be monitoring compliance with a CEMS.
60.4385	Excess emissions for fuel sulfur monitoring	No	Will use tariff.
60.4390	Reporting requirements for emergency or research combustion turbines	No	No applicable units on-site.
60.4395	When are reports due	Yes	Reports must be postmarked by the 30th day following the end of each 6-month period.
60.4400	Initial and annual performance test for NO_x	No	A CEMS will be used for monitoring compliance.
60.4405	Initial performance test if using a NO_x CEMS	Yes	Use RATA to satisfy requirements of 40 CFR 60.8.
60.4410	Establishing valid parameter ranges for NO_x	No	A CEMS will be used for monitoring compliance instead of a continuous parameter monitoring system.
60.4415(a)(1)	Initial and subsequent performance tests for SO_2	Yes	Collect and analyze a fuel sample annually.
60.4415(a)(2) and (3)	Stack test for SO_2	No	Will use option 1 instead of options 2 and 3.

40. A summary of the Subpart Dc requirements and their applicability to the Fractionator Feed Heater is provided below:

Table 10: 40 CFR Part 60, Subpart Dc New Source Performance Standards Applicability:

Subpart Dc Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.40c	Applicability and delegation of authority	Yes	The fractionator feed heater has a heat input greater than 10 MMBtu/h but less than 100 MMBtu/h and will commence construction after June 19, 1989.
60.41c	Definitions	Yes	These are applicable, but do not establish any specific requirements.
60.42c	Standard for sulfur dioxide	No	The fractionator feed heater burns only natural gas. It is not subject to any SO_2 standards.

Subpart Dc Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.43c	Standard for particulate matter	No	The fractionator feed heater burns only natural gas. The boiler is not subject to any PM standards..
60.44c	Compliance and performance test methods and procedures for sulfur dioxide	No	These requirements do not apply because the fractionator feed heater is not subject to any SO_2 standards.
60.45c	Compliance and performance test methods and procedures for particulate matter	Yes	The fractionator feed heater is designed to combust only natural gas; the PM emissions source testing requirements do not apply.
60.46c	Emission monitoring for sulfur dioxide	No	These requirements do not apply because the fractionator feed heater is not subject to any SO_2 standards.
60.47c	Emission monitoring for particulate matter	No	Do not apply because the fractionator feed heater is not subject to any PM standards.
60.48c	Reporting and recordkeeping requirements	Yes	The applicable requirements will be included in the permit.

41. A summary of the Subpart Kb requirements and their applicability to the Naphtha and Off-Spec Tanks are provided below:

Table 11: 40 CFR Part 60, Subpart Kb New Source Performance Standards Applicability:

Subpart Kb Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.110b	Applicability and designation	Yes	The naphtha product storage and off-spec tanks will have a storage capacity greater than 151 cubic meters, will store volatile organic liquids with a true vapor pressure of greater than or equal to 3.5 kilopascals, and be constructed after July 23, 1984. Therefore, the naphtha product storage tank and off-spec tank meet the applicability requirements of this subpart.
60.111b	Definitions	Yes	These are applicable, but do not establish any specific requirements.
60.112b	Standards for volatile organic compounds	Yes	The naphtha product storage and off-spec tanks will be required to be equipped with a control device identified in this section. These tanks will be equipped with an internal floating roof meeting the specifications outlined in this section.
60.113b	Testing and procedures	Yes	This section outlines inspection, maintenance and reporting procedures for each type of control device specified in 60.113b. The permittee will be required to comply with these

Subpart Kb Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
			procedures for the naphtha product storage and off-spec tanks.
60.114b	Alternate means of emission limitation	Yes	The requirements and methods to apply an alternate means of emissions control to storage tanks. Red Rock may choose to install and comply with alternate means of emission limitation.
60.115b	Reporting and recordkeeping requirements	Yes	Sets forth the reporting and recordkeeping requirements of this subpart. These requirements will be included in the permit for the naphtha product storage and off-spec tanks.
60.116b	Monitoring of operations	Yes	The following information shall be recorded and kept readily accessible for each subject tank: dimensions of the storage vessel; identity of the VOL stored; period of storage; and the maximum true vapor pressure of the VOL during the storage period.
60.117	Delegation of authority	Yes	This is applicable, but does not establish any specific requirements.

42. A summary of the Subpart VVa requirements and applicability for equipment leaks in the synthetic organic chemicals manufacturing is provided below.

Table 12: 40 CFR Part 60, Subpart VVa New Source Performance Standards Applicability:

Subpart VVa Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.480a	Applicability and designation of affected facility	Yes	Identifies facilities in the synthetic organic chemicals manufacturing industry; commences construction after November 7, 2006; produces any one chemical listed in 40 CFR 60.489 in quantities greater than or equal to 1,102 tons per year is subject to this subpart. The applicant meets these applicability requirements.
60.481a	Definitions	Yes	These are applicable, but do not establish any specific requirements.
60.482-1a	Standards: General	Yes	Identifies general standards, compliance methods, monitoring schedules, and other requirements for facilities subject to this subpart.
60.482-2a	Standards: Pumps in light liquid service	Yes	Identifies monitoring, maintenance and remediation methods and schedules for pumps in light liquid service. RRB may include pumps in light liquid service.

Subpart VVa Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.482-3a	Standards: Compressors	Yes	Identifies construction and operation requirements, monitoring, maintenance and remediation methods and schedules for compressors.
60.482-4a	Standards: Pressure relief devices in gas/vapor service	Yes	Identifies emission limits to indicate a leak and operating standards for pressure relief valves. RRB may include pressure relief devices in gas/vapor service.
60.482-5a	Standards: Sampling connection systems	Yes	Identifies standards for sampling connection lines. RRB may include sampling connection lines.
60.482-6a	Standards: Open-ended valves or lines	Yes	Identifies standards for open-ended valves or lines. RRB may include open ended valves or lines.
60.482-7a	Standards: Valves in gas/vapor service and light liquid or heavy liquid service	Yes	Identifies standards for valves in gas/vapor service and light liquid or heavy liquid service. RRB may include equipment in gas/vapor, light liquid and heavy liquid service.
60.482-8a	Standards: Pumps, valves and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service	Yes	Identifies standards for pumps, valves and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service. RRB may include pumps, valves and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.
60.482-9a	Standards: Delay of repair	Yes	Identifies procedures for repairing leaking equipment when repairs cannot be completed within 15 days of discovery.
60.482-10a	Standards: Closed vent systems and control devices	Yes	Identifies standards for closed vent systems and control devices. Any such equipment installed at the permitted facility will comply with this section.
60.482-11a	Standards: connectors in gas/vapor service and in light liquid service	Yes	Identifies standards for connectors in gas/vapor service and in light liquid service. RRB may include connectors in gas/vapor service and in light liquid service.
60.483-1a	Alternative standards for valves-allowable percentage of valves leaking	Yes	Identifies alternate standards for valves. RRB may choose to comply with this alternate standard.
60.483-2a	Alternative standards for valves-skip period leak detection and repair	Yes	Identifies alternate standards for valves. RRB may choose to comply with this alternate standard.
60.484a	Equivalence of means of emission limitation	Yes	Identifies requirements and methods to apply an alternate means of emissions control. RRB may choose to comply with this alternate standard.

Subpart VVa Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.485a	Test methods and procedures	Yes	Identifies performance test methods and procedures appropriate to comply with this subpart.
60.486a	Recordkeeping requirements	Yes	Identifies methods to identify leaks and general recordkeeping requirements for facilities subject to this subpart.
60.487a	Reporting requirements	Yes	Sets forth required content for semiannual reports and other reporting requirements for facilities subject to this subpart.
60.488a	Reconstruction	Yes	This is applicable but does not establish any specific requirements.
60.489a	List of chemicals produced by affected facilities	Yes	These are applicable, but do not establish any specific requirements.

43. A summary of the Subpart NNN requirements and applicability for volatile organic compound (VOC) emissions from synthetic organic chemicals manufacturing is provided below:

Table 13: 40 CFR Part 60, Subpart NNN New Source Performance Standards Applicability:

Subpart NNN Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.660	Applicability and designation of affected facility	Yes	Identifies the facility subject to this subpart as any distillation unit that produces, as a product, co-product, by-product, or intermediate, any chemical listed in 40 CFR 60.667 that commenced construction after December 30, 1983. The fractionating, side stripping, and hydrocracking columns have the potential to produce, as a byproduct, one or more of the listed chemicals. These columns will discharge into a recovery system that will be entirely enclosed and therefore will have a vent stream flow rate less than 0.008 scm/min. The exemption identified in 40 CFR 60.660(c)(6) will apply and the permittee will be exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §60.664(h) and paragraphs (i), (l)(5), and (o) of §60.665.
60.661	Definitions	Yes	These are applicable, but do not establish any specific requirements.

Subpart NNN Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.662	Standards	No	Identifies standards for emission reduction and compliance date guidelines. The system is entirely enclosed and no emissions are expected. No further action is required.
60.663	Monitoring of emissions and operations	No	Identifies monitoring, recording and operating requirements for emissions and emission control devices used to comply with this subpart. The system is entirely enclosed and no emissions are expected. No further action is required.
60.664	Test methods and procedures	Yes	The permittee will be required to comply with 60.664(h) of this subpart.
60.665	Reporting and recordkeeping requirements	Yes	Red Rock will be required to comply with paragraphs (i), (l)(5), and (o) of 40 CFR 60.665 of this subpart.
60.666	Reconstruction	Yes	This is applicable but does not establish any specific requirements.
60.667	Chemical affected by Subpart NNN	Yes	These are applicable, but do not establish any specific requirements.
60.668	Delegation of authority	Yes	This is applicable, but does not establish any specific requirements.

44. A summary of the Subpart RRR requirements and applicability for volatile organic compound (VOC) emissions from synthetic organic chemicals manufacturing industry (SOCMI) reactor process is provided below:

Table 14: 40 CFR Part 60, Subpart RRR New Source Performance Standards Applicability:

Subpart RRR Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.700	Applicability and designation of affected facility	Yes	Identifies the facility subject to this subpart as a process unit that produces, as a product, co-product, by-product, or intermediate, any chemical listed in 40 CFR 60.707 and that commences construction after June 29, 1990. The pyrolysis/gasifier reactor and FT reactor have the potential to produce, as a byproduct, one or more of the listed chemicals. Each unit will discharge into a recovery system that will be entirely enclosed and, therefore, each will have a vent stream flow rate less than 0.011 scm/min. The exemption identified in 40 CFR 60.700(c)(4) will

Subpart RRR Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
			apply and the permittee is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §60.704(g) and 60.705 (h), (l)(4), and (o).
60.701	Definitions	Yes	These are applicable, but do not establish any specific requirements.
60.702	Standards	No	Identifies standards for emission reduction and compliance date guidelines. The systems are entirely enclosed and no emissions are expected. No further action is required.
60.703	Monitoring of emissions and operations	No	Identifies monitoring, recording and operating requirements for emissions and emission control devices used to comply with this subpart. The systems are entirely enclosed and no emissions are expected. No further action is required.
60.704	Test methods and procedures	Yes	The permittee will be required to comply with 60.704(g) of this subpart.
60.705	Reporting and recordkeeping requirements	Yes	The permittee will be required to comply with paragraphs (h), (l)(4), and (o) of 60.705.
60.706	Reconstruction	Yes	This is applicable but does not establish any specific requirements.
60.707	Chemical affected by Subpart RRR	Yes	These are applicable, but do not establish any specific requirements.
60.708	Delegation of authority	Yes	This is applicable, but does not establish any specific requirements.

45. A summary of the Subpart IIII requirements and their applicability to the emergency fire pump engine is provided below:

Table 15: 40 CFR Part 60, Subpart IIII New Source Performance Standards Applicability:

Subpart IIII Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.4200	Applicability	Yes	The Clark 345 Hp, Tier 3, 9.0 liter/cylinder fire pump engine to be installed at RRB will be subject to this subpart.
60.4201 – 60.4204	Engine manufacturer and non-emergency engine requirements	No	Requirements are not applicable. No further action required.
60.4205	Emission standards for owners and operators - emission standards	Yes	Identifies emission standards for the proposed fire pump engine. Table 4 for 345 hp, 9.0 liter/cylinder fire pump engine.

Subpart IIII Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.4206	Emission standards for owners and operators - duration of emission standards	Yes	The emission standards for the fire pump engine set forth in 40 CFR 60.4205, Table 4 shall be met over the entire life of the engine.
60.4207	Fuel requirements for owners and operators	Yes	Identifies fuel requirements for proposed fire pump engine.
60.4208	Deadline for importing or installing stationary CI ICE produced in previous model used	No	This section disallows the installation of a stationary CI ICE that does not meet the applicable requirements for 2008 model year engines. The fire pump engine to be installed at the facility will meet the applicable requirements for 2008 model year engines. No further action is needed.
60.4209	Monitoring requirements	Yes	Identifies monitoring requirements for non-resettable hour meter.
60.4210	Manufacturer requirements	No	Not applicable. No further action required.
60.4211	Compliance requirements for owners	Yes	Identifies compliance requirements for the proposed fire pump engine.
60.4212	Testing requirements: Displacement less than 30 L/cylinder		Identifies the test methods and procedures for stationary CI ICE with a displacement of less than 30 liters per cylinder. The displacement of neither the proposed fire pump engine nor emergency generator is known at this time. If the displacement of either engine is less than 30 liters per cylinder, the test methods specified in this section will apply. Potentially applicable requirements are included in the permit.
60.4213	Testing requirements: Displacement greater than 30 L/cylinder		Identifies the test methods and procedures for stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder. The displacement of neither the proposed fire pump engine nor emergency generator is known at this time. If the displacement of either engine is greater than or equal to 30 liters per cylinder, the test methods specified in this section will apply. Potentially applicable requirements are included in the permit.
60.4214	Notification, reports and recordkeeping	Yes	Identifies initial notification, reports and labeling requirements.
60.4215	Requirements for Guam, America Samoa, and the common wealth of the Northern Mariana Islands	No	Not applicable. No further action required.
60.4216	Engine in Alaska	No	Not applicable. No further action required.

Subpart IIII Citation	Description	Applicable (yes/no)	Reason for Not Being Applicable
60.4217	Special fuels provisions	No	Not applicable. No further action required.
60.4218	General provisions	Yes	These are applicable, but do not establish any specific requirements.
60.4219	Definitions	Yes	These are applicable, but do not establish any specific requirements.

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS APPLICABILITY

46. 40 CFR Part 63, Subpart ZZZZ –The fire pump is also subject the National Emissions Standards for Hazardous Air Pollutant (NESHAP) for stationary reciprocating internal combustion engines. Since the facility is not a major source of hazardous air pollutants, compliance with NSPS Subpart IIII will ensure compliance with the NESHAP. [40 CFR Part 63, Subpart ZZZZ]

47. 40 CFR Part 63, Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources. The natural gas fired Fractionator Feed Heater is not subject to area source boiler MACT, Subpart JJJJJJ in accordance with 40 CFR 63.11195(e).

48. 40 CFR Part 63, Subpart HH – "National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities". The proposed facility is not subject to Subpart HH because the permittee will not be an oil and natural gas production facility.

49. 40 CFR Part 63, Subpart YYYY- "National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines". The permittee is not subject to Subpart YYYY for stationary combustion turbines because the facility is not located at a major source of hazardous air pollutants.

50. 40 CFR Part 63, Subpart VVVVVV- "National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources". The facility is not subject to Subpart VVVVVV for chemical manufacturing area sources because the permittee will not process, use or produce any of the compounds listed in Table 1 of Subpart VVVVVV.

51. The source is subject to the following updated federal standards or requirements that, at time of permit issuance, have not been adopted by the Environmental Quality Commission. For any violations of the following specific regulation, the permittee may be subject to enforcement action by EPA, but not DEQ. DEQ retains the authority to modify the permit or issue attachments as provided in Oregon Administrative Rule Chapter 340 Division 216 if the EQC adopts these regulations.

Table 16: Applicable Subpart A – General Provisions

Applicable Federal Standards Not Yet Adopted by EQC			
40 CFR Part	**Subpart**	**Federal Register Citation**	**Date of Promulgation**
60	A - General Provisions	83 FR 56720	11/14/2018
60	A - General Provisions	84 FR 47882	09/11/2019
63	A - General Provisions	83 FR 56725	11/14/2018
63	A - General Provisions	84 FR 47882	09/11/2019

GREENHOUSE GAS REPORTING APPLICABILITY

52. OAR Chapter 340 Division 215 is applicable to the source because emissions of greenhouse gases exceed 2,500 metric tons (2,756 short tons) of CO_2 equivalents per year.

REASONABLY AVAILABLE CONTROL TECHNOLOGY APPLICABILITY

53. The RACT rules are not applicable to this source because it is not in the Portland AQMA, Medford AQMA, or Salem SKATS.

TYPICALLY ACHIEVABLE CONTROL TECHNOLOGY APPLICABILIT

54. The source is likely meeting OAR 340-226-0130 Highest and Best Practicable Treatment and Control and Typically Achievable Control Technology (TACT) by:

    a. Installing and operating Baghouses (CE10) and (CE15) control devices that are required to perform the following maintenance and work practice requirements:
        i. Permittee will inspect, record and maintain daily baghouse pressure drops between 0.1 inches w.c. and 6.0 inches w.c.;
        ii. Permittee will inspect the baghouses at least once each calendar month of operation for physical degradation that could affect the performance of the baghouses; and
        iii. When replacing fabric filter bags in the baghouses, the permittee may not substitute a bag with lower efficiency specification than 99%.
    b. Installing and operating Vent Filters (CE11) and (CE08) control devices that are required to:
        i. Permittee will inspect, record and maintain daily vent filter pressure drops between 0.1 inches w.c. and 6.0 inches w.c.;
        ii. Permittee will inspect the vent filters at least once each calendar month of operation for physical degradation that could affect the performance of the vent filters; and
        iii. Permittee will replace the vent filters, as required, to ensure continued high efficiency control of particulate emissions.
    c. Installing and operating Gasifier Startup/Shutdown/Upset Flare (CE07) control device that is required to:

i. Permittee will inspect, measure, record and maintain the weekly volume of natural gas used in the flare pilot to ensure good combustion practices; and,
ii. Permittee will ensure good combustion practices are achieved when burning process gas, by using a sufficient volume of natural gas in the pilot.

d. Installing and operating Carbon Canisters (CE13) and (CE14) control devices that are required to:
i. Permittee will maintain a carbon canister pressure differential not to exceed 10 psi to ensure good capture efficiency in accordance with the manufacturer specifications;
ii. Permittee will record system operating conditions, check for corrosion, and drain condensate weekly or as needed; and,
iii. Permittee will inspect and record daily hours of product load-outs for each carbon canister.

55. Pursuant to OAR 340-226-0130(2)(a), the devices subject to NSPS Subparts Db, Dc, KKKK, Kb, VVA, NNN, RRR and IIII are exempt from applicability of the State's TACT/Highest and Best Rules.

SOURCE TESTING

PROPOSED TESTING

56. An initial performance test must be conducted on the gas turbine (EU33) within 60 days of achieving the maximum production rate but no later than 180 days after startup.as required in §60.8. Source testing is required to demonstrate compliance with the nitrogen oxide (NO_x) emission limits in §60.4320 and the permit term as shown in Table 17 below:

Table 17: NSPS Source Testing Requirements:

Source	Emission Parameter	Source Test Dates
Gas Turbine at the SCR stack	Nitrogen Oxide (NO_x)	60 to 180 days after startup

57. Unless otherwise approved in writing by DEQ, the permittee must source test within 60 days of achieving the maximum production rate but no later than 180 days after startup and one year prior to the permit expiration date, the combined gas turbine (EU33) and recycle heater (EU34) emissions at the SCR to verify the following factors:

Table 18: Emission Factor Verification Source Testing Requirements:

<table>
<tr><th>Source</th><th>Emission Parameter</th><th>Source Test Dates</th></tr>
<tr><td rowspan="4">Gas Turbine and Recycle Heater at SCR</td><td>PM, PM_{10} and $PM_{2.5}$</td><td rowspan="4">60 to 180 days after startup and one year prior to the permit expiration date</td></tr>
<tr><td>Volatile Organic Compounds (VOCs)</td></tr>
<tr><td>Formaldehyde</td></tr>
<tr><td>Ammonia Slip</td></tr>
</table>

58. The following production and control device parameters will be recorded during the tests:

a. Visible emissions as measured by EPA Method 9 for a period of at least eighteen minutes during or within 30 minutes before or after each test run;
b. Nitrogen Oxide (NO_x) emissions of the turbine after the selective catalytic reduction (SCR) unit using EPA Methods 7E and 3A, or EPA Method 20 and record the following:
   i. NO_x concentration, ppm by volume, lb/MMBtu, lb/MWh;
   ii. The gas stack gas flow rate, using EPA Methods 1 and 2;
   iii. Electrical and thermal outputs from the unit;
   iv. Barometric pressure at test, mm Hg;
   v. Ambient temperature, °K;
   vi. Humidity of ambient air, g H2O/g air;
   vii. Fuel consumption, scf/hour; and,
   viii. Natural gas usage (MMscf) for the turbine unit.
c. Particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions of the combined gas turbine recycle heater emissions must be tested at the selective catalytic reduction unit. The PM emissions must use EPA Methods 1-5 and 202, or other DEQ approved test methods. The PM_{10} and $PM_{2.5}$ emissions must be tested using EPA Methods 1-4, 201A & 202 or other DEQ approved test methods. The following must be recorded during the source test:
   i. Visible emissions as measured by EPA Method 9 for a period of at least eighteen minutes during or within 30 minutes before or after each test run;
   ii. Natural gas usage (MMscf) for each unit; and
   iii. PM, $PM_{10,}$ $PM_{2.5}$, emission concentrations are to be reported in terms of lbs/hr and lbs/MMscf.
d. Volatile Organic Compounds (VOCs) of the combined gas turbine recycle heater emissions must be tested at the selective catalytic reduction unit. The VOC emissions must be tested using EPA Method 18, 25A or 320, or other DEQ approved test methods.
e. Formaldehyde from the combined gas turbine recycle heater emissions must be tested at the selective catalytic reduction unit. Formaldehyde emissions must be tested using EPA Method 323, or other DEQ approved test methods.
f. Ammonia emissions from the combined gas turbine recycle heater emissions must be tested at the selective catalytic reduction unit. The ammonia emissions must be tested using test method CTM-027, or other DEQ approved test methods.

59. The permit requires testing at least annually to verify the accuracy of the continuous monitoring systems (CEMS) for nitrogen oxides in accordance with §60.4405 and carbon monoxides. These tests are referred to as Relative Accuracy Test Audits (RATA) that are conducted by an independent third party using approved test methods and procedures.

PUBLIC NOTICE

Pursuant to OAR 340-216-0066(4)(a)(A), issuance of Standard Air Contaminant Discharge Permits require public notice in accordance with OAR 340-209-0030(3)(c), which requires DEQ to provide notice of the proposed permit action and a minimum of 35 days for interested persons to submit written comments. **The public notice was issued on Oct. 14, 2020 and the comment period will end on Nov. 19, 2020.** In addition, a virtual public hearing has been scheduled for **Nov. 16, 2020** to allow interested persons to submit oral comments Hearing details are located in the public notice.

WW/dw:

ATTACHMENT A – EMISSION DETAIL SHEETS

The basis for the Plant Site Emission Limits provided below are calculated using the potential to emit for each pollutant using the maximum throughput and established emission factors. References for the emission factors are also provided. Actual emissions are typically below the potential to emit.

Biomass Receiving and Storage:

EP#	CE#	EU#	Unit Description	Pollutant	Air Flow (DSCFM)	Grain Loading (gr/dscft)	EF Citation	Emissions	
								lbs/hr	tpy
EP13	CE10	EU01	Biomass Truck Receiving #1	PM	191	0.005	Baghouse Manufacturer	8.20E-03	3.59E-02
EP21	CE15	EU02	Biomass Truck Receiving #2	PM	191	0.005		8.20E-03	3.59E-02
EP14	CE11	---	Surge Bin Vent Filters	PM	72	0.005	Vent Filter Manufacturer	3.11E-03	1.36E-02
EP09	CE08	EU25	Biochar Silo	PM	50	0.005		2.14E-03	9.39E-03
							Total PM	**2.16E-02**	**9.48E-02**
EP13	CE10	EU01	Biomass Truck Receiving #1	PM_{10}	191	0.005	Baghouse Manufacturer	8.20E-03	3.59E-02
EP21	CE15	EU02	Biomass Truck Receiving #2	PM_{10}	191	0.005		8.20E-03	3.59E-02
EP14	CE11	---	Surge Bin Vent Filters	PM_{10}	72	0.005	Vent Filter Manufacturer	3.11E-03	1.36E-02
EP09	CE08	EU25	Biochar Silo	PM_{10}	50	0.005		2.14E-03	9.39E-03
							Total PM_{10}	**2.16E-02**	**9.48E-02**
EP13	CE10	EU01	Biomass Truck Receiving #1	$PM_{2.5}$	191	0.005	Baghouse Manufacturer	8.20E-03	3.59E-02
EP21	CE15	EU02	Biomass Truck Receiving #2	$PM_{2.5}$	191	0.005		8.20E-03	3.59E-02
EP14	CE11	---	Surge Bin Vent Filters	$PM_{2.5}$	72	0.005	Vent Filter Manufacturer	3.11E-03	1.36E-02
EP09	CE08	EU25	Biochar Silo	$PM_{2.5}$	50	0.005		2.14E-03	9.39E-03
							Total $PM_{2.5}$	**2.16E-02**	**9.48E-02**

Cooling Tower Emissions:

EP#	CE#	EU#	Unit Description	Pollutant	Circulating Flow Rate (gpm)	Drift Loss (%)	Drift Loss Citation	Emissions	
								lbs/hr	tpy
EP06	---	EU20	Cooling Tower	PM	30,000	0.001%	Manufacturer	0.18	7.88E-01
EP06	---	EU20		PM_{10}	30,000	0.001%		0.18	7.88E-01
EP06	---	EU20		$PM_{2.5}$	30,000	0.001%		0.18	7.88E-01

Assumptions/Limitations

Total dissolved solids (TDS) concentration (ppm) 1200

Biomass Conveyor Systems and Handling:

EP#	CE#	EU#	Unit Description [1]	Pollutant	Max Throughput		Emission Factor		EF Citation	Emissions [3]	
					tph	tpy	lb/ton-hr	lb/ton-yr		lbs/hr	tpy
FS04	---	EU04	Biomass Conveyor System	PM	50	438,000	3.54E-02	4.84E-03	AP-42 Section 13.2.4	1.77	1.06
FS06	---	EU31	Biomass Handling	PM	50	438,000	8.86E-03	1.21E-03		4.43E-01	2.65E-01
Total PM										**2.21**	**1.32**
FS04	---	EU04	Biomass Conveyor System	PM_{10}	50	438,000	1.68E-02	2.29E-03	AP-42 Section 13.2.4	8.38E-01	5.01E-01
FS06	---	EU31	Biomass Handling	PM_{10}	50	438,000	4.19E-03	5.72E-04		2.09E-01	1.25E-01
Total PM_{10}										**1.05**	**6.26E-01**
FS04	---	EU04	Biomass Conveyor System	$PM_{2.5}$	50	438,000	2.54E-03	3.47E-04	AP-42 Section 13.2.4	1.27E-01	7.59E-02
FS06	---	EU31	Biomass Handling	$PM_{2.5}$	50	438,000	6.34E-04	8.66E-05		3.17E-02	1.90E-02
Total $PM_{2.5}$										**1.59E-01**	**9.49E-02**

Max (lb/hr) wind speed [2] 37 mph
Average (tpy) wind speed [2] 8 mph
Estimated moisture content of stored wood chips [4] 5%

$$E=k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Notes:
[1] Assumes 4 conveyors in system
[2] Wind speeds from www.wunderground.com/history for Lakeview, OR
[3] Assumes 100% capture efficiency and 0% control efficiency.
[4] Conservative estimate

Biomass Flat Storage – Wind Erosion Emissions:

Activity	Emissions (lb/hr)			Emissions (tons/yr)		
	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$
FS05 – Wind Erosion	0.55	0.28	0.14	2.42	1.21	6.05E-01

Source: USEPA, 1989. Air/Superfund National Technical Guidance Study Series: Volume III - Estimation of Air Emissions from Cleanup Activities at Superfund Sites, Interim final report EPA-450/1-89-003, January.

Calculation Method:
1) Emission factor PM (lb/day/acre) = [1.7 X (s/1.5) X (365-p)/235) X (f/15) lb/day/acre
2) $E_{PM10} = E_{PM2.5} = E_{PM}/2$

Factor/Description	Factors
s = Silt Content (%)	3
p = # days with at least 0.01 inch of precipitation	90
f = % Wind > 12 mph (%)	50.0
Storage Days	365
Storage pile acreage	1.0

Truck Traffic Paved Roads Emissions:

EP#	CE#	EU#	Unit Description	Pollutant	VMT		Emission Factor	EF Citation	Emissions	
					hourly	Annually	lb/VMT		lbs/hr	tpy
FS09	---	---	Biomass Receiving	PM	2.1	7,008.0	0.18	AP-42 Section 13.2.1-1	0.38	0.64
FS09	---	---	Biomass Reclaim	PM	0.1	829.5	0.18		0.02	0.08
FS09	---	---	Biochar Loadout	PM	1.3	4,204.8	0.18		0.24	0.38
FS09	---	---	Product Loadout	PM	3.4	1,599.8	0.18		0.62	0.15
Total PM									**1.25**	**1.24**
FS09	---	---	Biomass Receiving	PM_{10}	2.1	7,008.0	0.04	AP-42 Section 13.2.1-1	0.08	0.13
FS09	---	---	Biomass Reclaim	PM_{10}	0.1	829.5	0.04		0.00	0.02
FS09	---	---	Biochar Loadout	PM_{10}	1.3	4,204.8	0.04		0.05	0.08
FS09	---	---	Product Loadout	PM_{10}	3.4	1,599.8	0.04		0.12	0.03
Total PM_{10}									**0.25**	**0.25**
FS09	---	---	Biomass Receiving	$PM_{2.5}$	2.1	7,008.0	0.01	AP-42 Section 13.2.1-1	1.87E-02	3.12E-02
FS09	---	---	Biomass Reclaim	$PM_{2.5}$	0.1	829.5	0.01		8.91E-04	3.70E-03
FS09	---	---	Biochar Loadout	$PM_{2.5}$	1.3	4,204.8	0.01		1.16E-02	1.87E-02
FS09	---	---	Product Loadout	$PM_{2.5}$	3.4	1,599.8	0.01		3.03E-02	7.13E-03
Total $PM_{2.5}$									**0.06**	**6.08E-02**

Assumptions:

	/truck	/hr	/yr	miles/trip
Biomass Receiving (tons):	25	132	438,000	0.4
Biomass Reclaim (tons):	5	50	438,000	0.01
Biochar Loadout (tons):	25	84	438,000	0.4
Product Loadout (gallons):	8,000	36,000	438,000	0.75

$$\boldsymbol{E = k\,(sL)^{0.91} \times (W)^{1.02}}$$

Where:

E = particulate emission factor (lb/VMT)	PM	PM_{10}	$PM_{2.5}$
k = particle size factor	0.011	0.0022	0.00054
sL = road surface silt loading	0.5		
W = average weight (tons) of vehicles	29		

Selective Catalytic Reduction (SCR) Stack Emissions:

EP#	CE#	EU#	Unit	Pollutant	Max Throughput		Emission Factor		EF Citation	Emissions [3]	
										lbs/hr	tpy
EP02	CE06	EU33 & EU34	SCR Stack	PM	0.2567	MMscf/hr	7.60	(lb/MMscf)	AP-42 Section 1.4	1.95	8.54
				PM_{10}	0.2567	MMscf/hr	7.60	(lb/MMscf)		1.95	8.54
				$PM_{2.5}$	0.2567	MMscf/hr	5.13	(lb/MMscf)	[1]	1.32	5.77
				NOx	8760	hrs/yr	6.00	lb/hr	Manufacturer (SCR Control)[2]	6.00	26.28
				SO_2	0.2567	MMscf/hr	0.6	(lb/MMscf)	AP-42 Section 1.4	0.15	0.67
				VOC	0.2567	MMscf/hr	5.5	(lb/MMscf)		1.41	6.18
				CO	8760	hrs/yr	7.00	lb/hr	Manufacturer (SCR Control)[3]	7.00	30.66

[1] PM2.5 emission factor from England, G.C., "Development of Fine Particulate Emission Factors and Speciation Profiles for Oil and Gas-fired Combustion Systems, Final Report, 2004." Table 3.1, PM2.5 Mass Emission Factor for Gas-Fired Gas-Fired Boilers and Steam Generators.
[2] NOx emission factor from the manufacturer is listed as 6.5 parts per million (ppm) at 3% oxygen. A safety factor is added.
[3] CO emission factor from the manufacturer is listed as 10 parts per million (ppm) at 3% oxygen. A safety factor is added.

Assumptions/Limitations

Fuel Type:		Natural Gas
Capacity:	total	226 MMBtu/hr
	EU33 Gas Turbine	158 MMBtu/hr
	EU34 Recycle Heater	108.1 MMBtu/hr
Heat Content:		1.037 MMBtu/MMscf
Operating Schedule:		8,760 hours/year

Flaring – Pilot Emissions:

EP#	CE#	EU#	Unit	Pollutant	Max Throughput	Emission Factor	EF Citation	Emissions	
					MMscf/hr	(lb/MMscf)		lbs/hr	tpy
EP03	---	EU15	Flaring Pilot	PM	0.0014	7.60	AP-42 Section 1.4	0.01	4.65E-02
				PM_{10}		7.60		0.01	4.65E-02
				$PM_{2.5}$		7.60		0.01	4.65E-02
				NOx		100		0.14	6.12E-01
				SO_2		0.6		0.00	4.65E-02
				VOC		5.5		0.01	3.37E-02
				CO		84		0.12	5.14E-01

Assumptions/Limitations

Fuel Type:		Natural Gas
Capacity:	total	1.5 MMBtu/hr
		0.0014 MMscf/hr
Heat Content:		1.037 MMBtu/MMscf
Operating Schedule:		8,760 hours/year

Gasifier Flare Emissions:

EP#	CE#	EU#	Unit	Pollutant	Max Throughput	Emission Factor	EF Citation	Emissions	
					(MMBtu/hr)	(lb/MMBtu)		lbs/hr	tpy
EP03	CE07	EU14	Flare - Gasifier	PM	400	0.005	AP-42 Section 1.6[1]	1.90	9.48E-02
				PM_{10}		0.004	AP-42 Section 1.6[1]	1.74	8.68E-02
				$PM_{2.5}$		0.003	AP-42 Section 1.6[1]	1.10	5.48E-02
				NOx		0.068	AP-42 Section 13.5	27.20	1.36
				SO_2		0.03	AP-42 Section 1.6	10.0	5.48E-02
				VOC		0.14	AP-42 Section 13.5	56.0	2.80
				CO		0.31	AP-42 Section 13.5	124.0	6.20

[1] Estimated 2% of wood residue combustion emission factor as a result of gasification process and additional flare destruction of $PM/PM_{10}/PM_{2.5}$. $PM/PM_{10}/PM_{2.5}$ Emission factors are (All Fuels - 0.017 lb/MMbtu + Wet Wood Mechanical Collector lb/MMbtu)

Assumptions/Limitations

Fuel Type: Biomass (bark and wet wood)
Capacity: total 400 MMBtu/hr
Operating Schedule: 10 Startups/year
10 hours/startup

Emergency Fire Pump Engine Emissions:

EP#	CE#	EU#	Unit	Pollutant	Max Throughput	Emission Factor	EF Citation	Emissions	
					(MMBtu/hr)	(lb/MMBtu)		lbs/hr	tpy
EP08	---	EU22	Emergency Fire Pump	PM	0.88	0.31	AP-42 Section 3.3	0.27	1.36E-02
				PM_{10}		0.31		0.27	1.36E-02
				$PM_{2.5}$		0.31		0.27	1.36E-02
				NOx		4.41		3.87	1.94E-01
				SO_2		0.29		0.25	1.36E-02
				VOC		0.36		0.32	1.58E-02
				CO		0.95		0.83	4.17E-02

Front End Loader Emissions [1]:

EP#	CE #	EU#	Unit	Pollutant	Max Throughput	Emission Factor	EF Citation	Emissions	
					(MMBtu/hr)	(lb/MMBtu)		lbs/hr	tpy
EP11 & EP12	---	EU31 & EU32	Front End Loaders #1 and #2	PM	0.64 (combined maximum operating hours of 13,060 hrs/yr)	8.23E-03	Tier 4 - Existing Permit	8.23E-03	5.41E-02
				PM_{10}		8.23E-03		8.23E-03	5.41E-02
				$PM_{2.5}$		8.23E-03		8.23E-03	5.41E-02
				NOx		1.65E-01		1.65E-01	1.08
				SO_2		1.11E-06	EPA's NON-ROAD2008a model	1.11E-06	7.31E-06
				VOC		7.82E-02	Tier 4 - Existing Permit	7.82E-02	5.14E-01
				CO		1.44		1.44	9.46

[1] Emissions from the front-end loaders (EP11 & EP12) are classified as categorical insignificant and are only included in the potential to emit to determine the applicability of new source review.

Assumptions/Limitations

Fuel Type: Diesel
Capacity: 250 hp
Operating Schedule: 8,760 hours – Front End Loader #1
4,300 hours – Front End Loader #2

Reactor Charge Heater Emissions:

EP#	CE#	EU#	Unit	Pollutant	Max Throughput		Emission Factor		EF Citation	Emissions	
										lbs/hr	tpy
EP17	---	EU39	Reactor Charge Heater	PM	0.0062	MMscf/hr	7.60	lb/MMscf	AP-42 Section 1.4	4.68E-02	2.05E-01
				PM_{10}	0.0062	MMscf/hr	7.60	lb/MMscf	AP-42 Section 1.4	4.68E-02	2.05E-01
				$PM_{2.5}$	0.0062	MMscf/hr	7.60	lb/MMscf	AP-42 Section 1.4	4.68E-02	2.05E-01
				NOx	0.0062	MMscf/hr	75	lb/MMscf	Vendor Data	4.62E-01	2.02
				SO_2	0.0062	MMscf/hr	0.6	lb/MMscf	AP-42 Section 1.4	3.70E-03	1.62E-02
				VOC	0.0062	MMscf/hr	5.5	lb/MMscf	AP-42 Section 1.4	3.39E-02	1.48E-01
				CO	6.3900	MMBtu/hr	0.31	lb/MMBtu	AP-42 Section 13.5[1]	1.98	8.68

[1] lb/mmbtu CO emission factor for elevated flares used to account for combustion of process tail and off gas.

Assumptions/Limitations

Fuel Type: Natural Gas
Capacity: 6.39 MMBtu/hr
0.0062 MMscf/hr
Heat Content: 1.037 MMBtu/MMscf
Operating Schedule: 8,760 hours/year

Fractionator Feed Heater Emissions:

EP#	CE#	EU#	Unit	Pollutant	Max Throughput		Emission Factor		EF Citation	Emissions	
										lbs/hr	tpy
EP18	---	EU40	Fract. Feed Heater	PM	0.0108	MMscf/hr	7.60	lb/MMscf	AP-42 Section 1.4	8.23E-02	3.60E-01
				PM_{10}	0.0108	MMscf/hr	7.60	lb/MMscf	AP-42 Section 1.4	8.23E-02	3.60E-01
				$PM_{2.5}$	0.0108	MMscf/hr	7.60	lb/MMscf	AP-42 Section 1.4	8.23E-02	3.60E-01
				NOx	0.0108	MMscf/hr	75	lb/MMscf	Vendor Data	8.12E-01	3.56
				SO_2	0.0108	MMscf/hr	0.6	lb/MMscf	AP-42 Section 1.4	6.50E-03	2.85E-02
				VOC	0.0108	MMscf/hr	5.5	lb/MMscf	AP-42 Section 1.4	5.96E-02	2.61E-01
				CO	11.23	MMBtu/hr	0.31	lb/MMbtu	AP-42 Section 13.5[1]	3.48	15.25

[1] lb/mmbtu CO emission factor for elevated flares used to account for combustion of process tail and off gas.

Assumptions/Limitations
Fuel Type: Natural Gas
Capacity: 6.39 MMBtu/hr
0.0062 MMscf/hr
Heat Content: 1.037 MMBtu/MMscf
Operating Schedule: 8,760 hours/year

Truck Load-out Emissions:

EP#	CE#	EU#	Unit	Pollutant	Max Throughput	Emission Factor	EF Citation	Emissions	
					1000 Gal/yr	lb/1000 Gal		lbs/hr	tpy
EP19	CE13	EU27	Jet Fuel	VOC		0.0374	AP-42 Section 5.2	0.01	1.74E-03
			Diesel	VOC		0.0346		0.01	7.44E-04
			Naphtha	VOC		4.8237		1.74	2.24E-01
							Total VOCs	**1.76**	**2.27E-01**

Rail Load-out Emissions:

EP#	CE#	EU#	Unit	Pollutant	Max Throughput	Emission Factor	EF Citation	Emissions	
					1000 Gal/yr	lb/1000 Gal		lbs/hr	tpy
EP20	CE14	EU28	Jet Fuel	VOC	9,300	0.0224	AP-42 Section 5.2	0.81	4.82E-02
			Diesel	VOC	4,300	0.0208		0.75	4.46E-02
			Naphtha	VOC	3,465	2.8942		1.04	5.01E-02
							Total VOCs	**2.60**	**1.43E-01**

Assumptions/Limitations

Product:	**Jet Fuel**	**Diesel**	**Naphtha**
Molecular Weight:	162	188	89.16
Product Temperature (R):	534.7	534.7	534.7
TVP (PSIA):	0.0099	0.0070	2.3217
Limited Loading (1,000 gal/hr):	36	36	36
Limited Loading (1,000 gal/yr):	9,300	4,300	3,465

	Truck	**Rail**
Saturation Factor:	1	0.6
Loading Rate (gpm):	600	600
Carbon Canister Control Efficiency:	99%	99%

$$L = 12.46 \frac{SPM}{T}$$

Where:
L = Loading Loss, lb VOC/1000 gal of liquid loaded
S = Saturation Factor (AP-42 Table 5.2-1)
P = True Vapor Pressure of Liquid Loaded, psia
M = Molecular Weight of Vapors, lb/lb-mole
T = Temperature of Bulk Liquid Loaded, R

Equipment Leaks Emissions:

Equipment Leaks Synthesis Process:

EP#	Source	Product	Comp. Count	Emission Factor	Uncontrolled Emission Rate	Subpart Vva Control Efficiency	Controlled Emission Rate	TOC Weight	Emissions	
				(kg/comp-hr)	(lbs/yr)		(lbs/yr)		(lbs/hr)	(tpy)
FS10	Valves	G/V	150	0.00597	1.97	0.87	0.26	100%	2.56E-01	1.12
FS10	Valves	LL	0	0.00403	0	0.84	0	100%	0	0
FS10	Pumps	LL	10	0.01990	0.44	0.69	0.14	100%	1.36E-01	5.94E-01
FS10	Compressor Seals	G/V	0	0.228	0	0.75	0	100%	0	0
FS10	Pressure-Relief Valves	G/V	10	0.104	2.29	0.87	0.30	100%	2.97E-01	1.30
FS10	Sampling Connections	All	0	0.015	0	0.87	0	100%	0	0
FS10	Open-ended Lines	All	0	0.0017	0	0.84	0	100%	0	0
FS10	Flanges	All	0	0.00183	0	0.84	0	100%	0	0
Total VOCs									**6.89E-01**	**3.02**

Equipment Leaks Hydroprocessing and Distillation:

EP#	Source	Product	Comp. Count	Emission Factor	Uncontrolled Emission Rate	Subpart Vva Control Efficiency	Controlled Emission Rate	TOC Weight	Emissions	
				(kg/comp-hr)	(lbs/yr)		(lbs/yr)		(lbs/hr)	(tpy)
FS10	Valves	G/V	150	0.00597	1.97	0.87	0.26	100%	2.56E-01	1.12
FS10	Valves	LL	0	0.00403	0	0.84	0	100%	0	0
FS10	Pumps	LL	10	0.01990	0.44	0.69	0.14	100%	1.36E-01	5.94E-01
FS10	Compressor Seals	G/V	0	0.228	0	0.75	0	100%	0	0
FS10	Pressure-Relief Valves	G/V	10	0.104	2.29	0.87	0.30	100%	2.97E-01	1.30
FS10	Sampling Connections	All	0	0.015	0	0.87	0	100%	0	0
FS10	Open-ended Lines	All	0	0.0017	0	0.84	0	100%	0	0
FS10	Flanges	All	0	0.00183	0	0.84	0	100%	0	0
Total VOCs									**6.89E-01**	**3.02**

Equipment Leaks Tank Farm and Loadout:

EP#	Source	Product	Comp. Count	Emission Factor	Uncontrolled Emission Rate	Subpart Vva Control Efficiency	Controlled Emission Rate	TOC Weight	Emissions	
				(kg/comp-hr)	(lbs/yr)		(lbs/yr)		(lbs/hr)	(tpy)
FS10	Valves	G/V	100	0.00597	1.31	0.87	0.17	100%	1.71E-01	7.48E-01
FS10	Valves	LL	0	0.00403	0	0.84	0	100%	0	0
FS10	Pumps	LL	10	0.01990	0.44	0.69	0.14	100%	1.36E-01	5.94E-01
FS10	Compressor Seals	G/V	0	0.228	0	0.75	0	100%	0	0
FS10	Pressure-Relief Valves	G/V	5	0.104	1.14	0.87	0.15	100%	1.49E-01	6.51E-01
FS10	Sampling Connections	All	0	0.015	0	0.87	0	100%	0	0
FS10	Open-ended Lines	All	0	0.0017	0	0.84	0	100%	0	0
FS10	Flanges	All	0	0.00183	0	0.84	0	100%	0	0
								Total VOCs	**4.55E-01**	**1.99**

Assumptions/Limitations
Operating Schedule: 8,760 hours/year

Storage Tank Emissions:

EP#	CE#	EU#	Unit	Tank Volume Gallons	Max Throughput Gal/hr	Emission lb/yr	EF Citation	Emissions	
								lbs/hr	tpy
---	---	TK01	Jet Fuel Tank	300,000	9,300,000	255.36	Tanks 4.0.9	2.92E-02	1.28E-01
---	---	TK02	Jet Day Tank #1	8,000	5,000,000	26.85		3.07E-03	1.34E-02
---	---	TK03	Jet Day Tank #2	8,000	5,000,000	26.85		3.07E-03	1.34E-02
---	---	TK04	Diesel Tank	300,000	4,300,000	105.50		1.20E-02	5.28E-02
---	---	TK06	Diesel Day Tank	15,000	4,300,000	25.77		2.94E-03	1.29E-02
---	---	TK07	Naphtha Tank	150,000	3,465,000	1,107.39		1.26E-01	5.54E-01
---	---	TK08	Off-Spec Tank	50,000	900,000	1,088.66		1.24E-01	5.44E-01
							Total VOCs	**3.01E-01**	**1.32**

PM Emissions:

Emission Units	Process Description	Annual Throughput	EF	EF Reference	Emissions (tons/yr)
EP13	Biomass Truck Receiving #1 [(a)]	219,000 tons/yr	3.28E-04 lbs/ton	Manufacturer [1.]	3.59E-02
EP21	Biomass Truck Receiving #2 [(a)]	219,000 tons/yr	3.28E-04 lbs/ton	Manufacturer[1.]	3.59E-02
EP14	Biomass Conveying & Shredder [(b)]	438,000 tons/yr	6.21E-05 lbs/ton	Manufacturer [2.]	1.36E-02
FS04	Biomass Conveyor System [(b)]	438,000 tons/yr	4.84E-03 lbs/ton	AP-42 Section 13.2.4 [3.]	1.06
FS05	Biomass Storage Pile [(a)]	438,000 tons/yr	1.11E-02 lbs/ton	EPA-450/1-89-003	2.42
FS06	Biomass Handling [(b)]	438,000 tons/yr	1.21E-03 lbs/ton	AP-42 Section 13.2.4	2.65E-01
EP02	SCR Stack [(d)]	2,248.46 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	8.54
EP03	Gasifier Flare Exhaust Stack [(d)]	40,000 MMBtu/yr	4.74E-03 lb/MMBtu	AP-42 Section 1.6	9.48E-02
EP03	Flare Pilot [(d)]	12.25 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	4.65E-02
EP06	Cooling Tower [(d)]	8,760 hrs/yr	0.18 lb/hr	manufacturer	7.88E-01
EP08	Emergency Fire Pump [(d)]	87.8 MMBtu/yr	3.10E-01 lb/MMBtu	AP-42 Section 3.3	1.36E-02
EP17	Reactor Charge Heater [(d)]	54 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	2.05E-01
EP18	Fractionator Feed Heater [(d)]	94.9 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	3.60E-01
EP09	Biochar Silo [(c)]	262,800 tons/yr	7.1E-05 lb/ton	Manufacturer [2.]	9.39E-03
FS09	Truck Traffic (Paved Roads) [(b)]	13,642 VMT/yr	0.182 lb/VMT	AP-42 Section 13.2.1	1.24
EP11	Front End Loader #1 [(b)]	8,760 hrs/yr	8.231×10^{-03} lbs/hr	Tier 4 - 250Hp Engine. Specs	3.60E-02
EP12	Front End Loader #2 [(b)]	4,380 hrs/yr			1.80E-02
PM Total (tons/yr):					**15.19**

Footnotes are associated with aggregated emission factor grouping in the table below.

PM Emission Factors:

Aggregated Process Descriptions	PM Emissions (tons/yr)	Annual Throughput	Emissions Factor	Process Activity Grouping
Biomass Received & stored [(a)]	2.49	438,000	1.14E-02 lb/ton	Biomass Received
Biomass Processing [(b)]	2.63	438,000	1.20E-02 lb/ton	Biomass Processed
Biochar Handling [(c)]	9.39E-03	262,800	7.14E-05 lb/ton	Biochar Produced
Fuel Production [(d)]	10.05	2,410	8.34 lb/MMscft	Natural Gas Combusted

Notes:

1. Schenk Process LLC, Model 114MCF361 baghouse emission factors with 0.01 gr/dscf grain loading.
2. Bin vent filter manufacturer emission factor with 0.01 gr/dscf grain loading.
3. Max wind speed from www.wunderground.com/history for Lakeview: 37 mph, Average wind speed 8 mph with an estimated 5% moisture of stored wood chips.

#. Emissions from the front-end loaders (EP11 & EP12) are classified as categorical insignificant and are only included in the potential to emit to determine the applicability of new source review.

Particulate Matter 10 microns (PM_{10})

Emission Units	Process Description	Annual Throughput	EF	EF Reference	Emissions (tons/yr)
EP13	Biomass Truck Receiving #1 [a]	219,000 tons/yr	3.28E-04 lbs/ton	Manufacturer	3.59E-02
EP21	Biomass Truck Receiving #2 [a]	219,000 tons/yr	3.28E-04 lbs/ton	Manufacturer	3.59E-02
EP14	Biomass Conveying & Shredder [b]	438,000 tons/yr	6.21E-05 lbs/ton	Manufacturer	1.36E-02
FS04	Biomass Conveyor System [b]	438,000 tons/yr	2.29E-03 lbs/ton	AP-42 Section 13.2.4	5.01E-01
FS05	Biomass Storage Pile [a]	438,000 tons/yr	5.53E-03 lbs/ton	EPA-450/1-89-003	1.21
FS06	Biomass Handling [b]	438,000 tons/yr	5.72E-04 lbs/ton	AP-42 Section 13.2.4	1.25E-01
EP02	SCR Stack [d]	2,248.46 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	8.54
EP03	Gasifier Flare Exhaust Stack [d]	40,000 MMBtu/yr	4.34E-03 lb/MMBtu	AP-42 Section 1.6	8.68E-02
EP03	Flare Pilot [d]	12.25 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	4.65E-02
EP06	Cooling Tower [d]	8,760 hrs/yr	0.18 lb/hr	manufacturer	7.88E-01
EP08	Emergency Fire Pump [d]	87.8 MMBtu/yr	3.10E-01 lb/MMBtu	AP-42 Section 3.3	1.36E-02
EP17	Reactor Charge Heater [d]	54 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	2.05E-01
EP18	Fractionator Feed Heater [d]	94.9 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	3.60E-01
EP09	Biochar Silo [c]	262,800 tons/yr	7.1E-05 lb/ton	Manufacturer	9.39E-03
FS09	Truck Traffic (Paved Roads) [b]	13,642 VMT/yr	0.182 lb/VMT	AP-42 Section 13.2.1	0.25
EP11	Front End Loader #1 [b]	8,760 hrs/yr	8.231×10^{-03} lbs/hr	Tier 4 - 250Hp Engine. Specs	3.60E-02
EP12	Front End Loader #2 [b]	4,380 hrs/yr			1.80E-02
PM_{10} Total (tons/yr):					**12.28**

Footnotes are associated with aggregated emission factor grouping in the table below.

PM_{10} Emission Factors:

Aggregated Process Descriptions	PM_{10} Emissions (tons/yr)	Annual Throughput	Emissions Factor	Process Activity Grouping
Biomass Received & stored [a]	1.28	438,000	5.85E-03 lb/ton	Biomass Received
Biomass Processing [b]	0.94	438,000	4.30E-03 lb/ton	Biomass Processed
Biochar Handling [c]	0.01	262,800	7.14E-05 lb/ton	Biochar Produced
Fuel Production [d]	10.04	2,410	8.34 lb/MMscft	Natural Gas Combusted

Particulate Matter 2.5 microns ($PM_{2.5}$)

Emission Units	Process Description	Annual Throughput	EF	EF Reference	Emissions (tons/yr)
EP13	Biomass Truck Receiving #1 [(a)]	219,000 tons/yr	3.28E-04 lbs/ton	Manufacturer	3.59E-02
EP21	Biomass Truck Receiving #2 [(a)]	219,000 tons/yr	3.28E-04 lbs/ton	Manufacturer	3.59E-02
EP14	Biomass Conveying & Shredder [(b)]	438,000 tons/yr	6.21E-05 lbs/ton	Manufacturer	1.36E-02
FS04	Biomass Conveyor System [(b)]	438,000 tons/yr	3.47E-04 lbs/ton	AP-42 Section 13.2.4	7.59E-02
FS05	Biomass Storage Pile [(a)]	438,000 tons/yr	2.76E-03 lbs/ton	EPA-450/1-89-003	6.05E-01
FS06	Biomass Handling [(b)]	438,000 tons/yr	8.66E-05 lbs/ton	AP-42 Section 13.2.4	1.90E-02
EP02	SCR Stack [(d)]	2,248.46 MMscf/yr	5.13 lb/MMscf	Manufacturer	5.77
EP03	Gasifier Flare Exhaust Stack [(d)]	40,000 MMBtu/yr	2.74E-03 lb/MMBtu	AP-42 Section 1.6	5.48E-02
EP03	Flare Pilot [(d)]	12.25 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	4.65E-02
EP06	Cooling Tower [(d)]	8,760 hrs/yr	0.18 lb/hr	manufacturer	7.88E-01
EP08	Emergency Fire Pump [(d)]	87.8 MMBtu/yr	3.10E-01 lb/MMBtu	AP-42 Section 3.3	1.36E-02
EP17	Reactor Charge Heater [(d)]	54 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	2.05E-01
EP18	Fractionator Feed Heater [(d)]	94.9 MMscf/yr	7.6 lb/MMscf	AP-42 Section 1.4	3.60E-01
EP09	Biochar Silo [(c)]	262,800 tons/yr	7.1E-05 lb/ton	Manufacturer	9.39E-03
FS09	Truck Traffic (Paved Roads) [(b)]	13,642 VMT/yr	0.182 lb/VMT	AP-42 Section 13.2.1	6.08E-02
EP11	Front End Loader #1 [(b)]	8,760 hrs/yr	$8.231x10^{-03}$ lbs/hr	Tier 4 – 250 Hp Engine Specs	3.60E-02
EP12	Front End Loader #2 [(b)]	4,380 hrs/yr			1.80E-02
$PM_{2.5}$ Total (tons/yr):					**8.15**

Footnotes are associated with aggregated emission factor grouping in the table below.

$PM_{2.5}$ Emission Factors:

Aggregated Process Descriptions	$PM_{2.5}$ Emissions (tons/yr)	Annual Throughput	Emissions Factor	Process Activity Grouping
Biomass Received & stored [(a)]	0.68	438,000	5.85E-03 lb/ton	Biomass Received
Biomass Processing [(b)]	0.22	438,000	4.30E-03 lb/ton	Biomass Processed
Biochar Handling [(c)]	0.01	262,800	7.14E-05 lb/ton	Biochar Produced
Fuel Production [(d)]	7.24	2,410	6.01 lb/MMscft	Natural Gas Combusted

Sulfur Dioxides (SO_2)

Emission Units	Process Description	Annual Throughput	EF	EF Reference	Emissions (tons/yr)
EP02	SCR Stack (1)	2,248 MMscf/yr	0.6 lb/MMscf	AP-42 Section 1.4	6.74E-01
EP03	Gasifier Flare Exhaust Stack (2)	100 hrs/yr	10 lb/hr	AP-42 Section 1.6	5.48E-02
EP03	Flare Pilot	12.25 MMscf/yr	0.6 lbs/MMscf	AP-42 Section 1.4	4.65E-02
EP08	Emergency Fire Pump (3)	100 hrs/yr	0.29 lbs/MMBtu	AP-42 Section 3.3	1.36E-02
EP17	Reactor Charge Heater	54 MMscf/yr	0.6 lb/MMscf	AP-42 Section 1.4	1.62E-02
EP18	Fractionator Feed Heater	94.9 MMscf/yr	0.6 lb/MMscf	AP-42 Section 1.4	2.85E-02
EP11	Front End Loader #1	8,760 hrs/yr	1.11E-06 lbs/hr	EPA's NONROAD2008a model	4.87E-06
EP12	Front End Loader #2	4,380 hrs/yr			2.44E-06
SO_2 Total (tons/yr):					**1.17**

(1) SCR emissions from the recycle heater and gas turbine.
(2) Gasifier flare process gas emissions are based on 100 hours of operation per year. (10 startups per year flaring process gas for 10 hours per event)
(3) Emergency Fire Pump emissions based 100 hours per year of maintenance and readiness testing.

Nitrogen Oxides (NO_x)

Emission Units	Process Description	Annual Throughput	EF	EF Reference	Emissions (tons/yr)
EP02	SCR Stack (1)	8,760 hrs/yr	6 lb/hr	Manufacturer	26.28
EP03	Gasifier Flare Exhaust Stack (2)	100 hrs/yr	27.2 lb/hr	AP-42 Section 13.5	1.36
EP03	Flare Pilot	12.25 MMscf/yr	100 lb/MMscf	AP-42 Section 1.4	6.12E-01
EP08	Emergency Fire Pump (3)	100 hrs/yr	3.87 lb/hr	AP-42 Section 3.3	1.94E-01
EP17	Reactor Charge Heater	54 MMscf/yr	75 lb/MMscf	Vendor Data	2.02
EP18	Fractionator Feed Heater	94.9 MMscf/yr	75 lb/MMscf	Vendor Data	3.56
EP11	Front End Loader #1	8,760 hrs/yr	1.65E-01 lbs/hr	Tier 4 - 250Hp Engine. Specs	7.23E-01
EP12	Front End Loader #2	4,380 hrs/yr			3.61E-01
NOx Total (tons/yr):					**35.11**

(1) SCR emissions from the recycle heater and gas turbine.
(2) Gasifier flare process gas emissions are based on 100 hours of operation per year. (10 startups per year flaring process gas for 10 hours per event)
(3) Emergency Fire Pump emissions based 100 hours per year of maintenance and readiness testing.

Carbon Monoxides (CO)

Emission Units	Process Description	Annual Throughput	EF	EF Reference	Emissions (tons/yr)
EP02	SCR Stack (1)	8,760 hrs/yr	7 lb/hr	Manufacturer	30.66
EP03	Gasifier Flare Exhaust Stack (2)	100 hrs/yr	124 lb/hr	AP-42 Section 13.5	6.20
EP03	Flare Pilot	12.25 MMscf/yr	84 lb/MMscf	AP-42 Section 1.4	5.14E-01
EP08	Emergency Fire Pump (3)	100 hrs/yr	0.83 lb/hr	AP-42 Section 3.3	4.17E-02
EP17	Reactor Charge Heater	6.39 MMBtu/yr	0.31 lbs/MMBtu	AP-42 Section 13.5	8.68
EP18	Fractionator Feed Heater	11.23 MMBtu/yr	0.31 lbs/MMBtu	AP-42 Section 13.5	15.25
EP11	Front End Loader #1	8,760 hrs/yr	1.44 lbs/hr	Tier 4 - 250Hp Engine. Specs	6.31
EP12	Front End Loader #2	4,380 hrs/yr			3.15
CO Total (tons/yr):					**70.80**

(1) SCR emissions from the recycle heater and gas turbine.
(2) Gasifier flare process gas emissions are based on 100 hours of operation per year. (10 startups per year flaring process gas for 10 hours per event)
(3) Emergency Fire Pump emissions based 100 hours per year of maintenance and readiness testing.

Volatile Organic Compounds (VOCs)

Emission Units	Process Description	Annual Throughput	EF	EF Reference	Emissions (tons/yr)
EP02	SCR Stack (1)	2,248.46 MMscf/yr	5.5 lb/MMscf	AP-42 Section 1.4	6.18
EP03	Gasifier Flare Exhaust Stack (2)	100 hrs/yr	56 lb/hr	AP-42 Section 13.5	2.80
EP03	Flare Pilot	12.25 MMscf/yr	5.5 lb/MMscf	AP-42 Section 1.4	3.37E-02
EP08	Emergency Fire Pump (3)	100 hrs/yr	0.83 lb/hr	AP-42 Section 3.3	1.58E-02
EP17	Reactor Charge Heater	53.98 MMscf/yr	5.5 lb/MMscf	AP-42 Section 1.4	1.48E-01
EP18	Fractionator Feed Heater	94.86 MMscf/yr	5.5 lb/MMscf	AP-42 Section 1.4	2.61E-01
EP11	Front End Loader #1	8,760 hrs/yr	7.82E-02 lbs/hr	Tier 4 - 250Hp Engine. Specs	5.14E-01
EP12	Front End Loader #2	4,380 hrs/yr			3.72E-04
EP19	Truck Load-out Jet Fuel	9,300 Mgal/yr	3.74E-02 lb/Mgal	AP-42 Section 5.2	1.74E-03
EP19	Truck Load-out Diesel Fuel	4,300 Mgal/yr	3.46E-02 lb/Mgal	AP-42 Section 5.2	7.44E-04
EP19	Truck Load-out Naphtha	3,465 MMgal/yr	4.8237 lb/MMgal	AP-42 Section 5.2	8.36E-02
EP20	Train Load-out Jet Fuel	9,300 MMgal/yr	2.24E-02 lb/MMgal	AP-42 Section 5.2	1.04E-03
EP20	Train Load-out Diesel Fuel	4,300 MMgal/yr	2.08E-02 lb/MMgal	AP-42 Section 5.2	4.46E-04
EP20	Train Load-out Naphtha	3,465 MMgal/yr	2.894 lb/MMgal	AP-42 Section 5.2	5.01E-02
FS10	Equipment Leaks	Mass Balance (NSPS Subpart Vva)			8.03
TK01	Jet Fuel Tank	Tanks 4.0.9			1.51E-01
TK02	Jet Fuel Day Tank 1				1.84E-02
TK03	Jet Fuel Day Tank 2				1.84E-02
TK04	Diesel Tank				1.14E-01
TK06	Diesel Day Tank				2.55E-02
TK07	Naphtha Tank				5.54E-01
TK08	Off-Spec Tank				5.44E-01
VOCs Total (tons/yr):					**19.--**

(1) SCR emissions from the recycle heater and gas turbine.
(2) Gasifier flare process gas emissions are based on 100 hours of operation per year. (10 startups per year flaring process gas for 10 hours per event)
(3) Emergency Fire Pump emissions based 100 hours per year of maintenance and readiness testing.

Operational Data

Processes			Annual Throughputs			
Emission Point ID	Emission Unit ID	Units				
EP02	EU33, EU34	SCR Stack	2,248	MMscft/yr	8,760	hrs/yr
EP03	EU14	Flare Pilot	12	MMscft/yr	8,760	hrs/yr
EP03	EU15	Gasifier Flare Exhaust Stack	40,000	MMBtu/hr	100	hrs/yr
EP16	EU38	Oil Water Separator	508,080	gal/yr	8,760	hrs/yr
EP08	EU22	Emergency Fire Pump	87.8	MMBtu/yr	100	hrs/yr
EP17	EU39	Reactor Charge Heater	53.98	MMscft/yr	55,976.4	MMBtu/yr
EP18	EU40	Fractionator Feed Heater	94.86	MMscft/yr	98,374.8	MMBtu/yr
EP11	EU31	Front End Loader #1	8,760	hrs/yr	113,880	gal/yr
EP12	EU32	Front End Loader #2	4,380	hrs/yr	56,940	gal/yr
EP19	EU27	Product Load-out - Truck				
		Jet Fuel	9.3	MMgal/yr	36	Mgal/hr
		Diesel	4.3	MMgal/yr	36	Mgal/hr
		Naphtha	3.465	MMgal/yr	36	Mgal/hr
EP20	EU28	Product Load-out - Rail				
		Jet Fuel	9.3	MMgal/yr	36	Mgal/hr
		Diesel	4.3	MMgal/yr	36	Mgal/hr
		Naphtha	3.465	MMgal/yr	36	Mgal/hr
FS10	FS10	Equipment VOC Leaks			8,760	hrs/yr
NA	TK01	Jet Fuel Tank	9,300,000	Gallons/yr	8,760	hrs/yr
	TK02	Jet Fuel Day Tank 1	5,000,000	Gallons/yr	8,760	hrs/yr
	TK03	Jet Fuel Day Tank 2	5,000,000	Gallons/yr	8,760	hrs/yr
	TK04	Diesel Tank	4,300,000	Gallons/yr	8,760	hrs/yr
	TK06	Diesel Day Tank	4,300,000	Gallons/yr	8,760	hrs/yr
	TK07	Naphtha Tank	3,465,000	Gallons/yr	8,760	hrs/yr
	TK08	Off-Spec Tank	900,000	Gallons/yr	8,760	hrs/yr

Green House Gas Emissions:

SCR Stack GHG Emissions:
..Recycle Heater (EU34) Capacity: 108.10 MMBtu/hr Natural Gas Usage: 913.17 MMscf/yr
Turbine (EU33) Capacity: 158.07 MMBtu/hr Natural Gas Usage 1,335.29 MMscf/yr

Emission Point	Pollutant	Max Throughput	Emission Factor	GWP (1)	Citation	Potential to Emit	
		(MMBtu/hr)	(lb/MMBtu)			(lbs/hr)	(tpy)
SCR Stack	CO_2	266.17	116.997	1	40CFR98	31,141	136,398
SCR Stack	CH_4	266.17	0.0022	25	40CFR98	15	64.120
SCR Stack	N_2O	266.17	0.00022	298	40CFR98	17	76.431
Total	**CO_2e**					**31,173**	**136,539**

(1) Global Warming Potentials Included (CO_2 = 1, NH_4 = 25, N_2O = 298)

Flare Pilot GHG Emissions:
Flare Pilot (EU15) Capacity: 1.5 MMBtu/hr Natural Gas Usage 12.25 MMscf/yr

Emission Point	Pollutant	Max Throughput	Emission Factor	GWP (1)	Citation	Potential to Emit	
		(MMBtu/hr)	(lb/MMBtu)			(lbs/hr)	(tpy)
Flare - Pilot	CO_2	1.45	116.997	1	40CFR98	170	743
Flare - Pilot	CH_4	1.45	0.0022	25	40CFR98	0.080	0.349
Flare - Pilot	N_2O	1.45	0.00022	298	40CFR98	0.095	0.416
Total	**CO_2e**					**170**	**744**

(1) Global Warming Potentials Included (CO_2 = 1, NH_4 = 25, N_2O = 298)

Gasifier Flare Process Gas GHG Emissions:
Flare Gasifier (EU13) Capacity 400 MMBtu/hr

Emission Point	Pollutant	Max Throughput	Emission Factor	GWP (1)	Citation	Potential to Emit	
		(MMBtu/hr)	(lb/MMBtu)			(lbs/hr)	(tpy)
Flare - Gasifier	CO_2	400	114.79	1	40CFR98	45,916	2,296
Flare - Gasifier	CH_4	400	0.007	25	40CFR98	70.000	3.500
Flare - Gasifier	N_2O	400	0.0014	298	40CFR98	166.880	8.344
Total	**CO_2e**					**46,153**	**2,308**

(1) Global Warming Potentials Included (CO_2 = 1, NH_4 = 25, N_2O = 298)

Emergency Fire Pump Engine GHG Emissions
Emergency Fire Pump (EU22) Capacity 0.88 MMBtu/hr

Emission Point	Pollutant	Max Throughput	Emission Factor	GWP (1)	Citation	Potential to Emit	
		(MMBtu/hr)	(lb/MMBtu)			(lbs/hr)	(tpy)
Emergency Fire Pump	CO_2	0.88	163.05	1	40CFR98	143	7.16
Emergency Fire Pump	CH_4	0.88	0.0066	25	40CFR98	0.145	0.01
Emergency Fire Pump	N_2O	0.88	0.00132	298	40CFR98	0.345	0.02
Total	**CO_2e**					**144**	**7.18**

(1) Global Warming Potentials Included (CO_2 = 1, NH_4 = 25, N_2O = 298)

Reactor Charge Heater GHG Emissions

Reactor Charge Heater (EU39) Capacity 6.39 MMBtu/hr Natural Gas Usage 53.98 MMscf/yr

Emission Point	Pollutant	Max Throughput (MMBtu/hr)	Emission Factor (lb/MMBtu)	GWP (1)	Citation	Potential to Emit (lbs/hr)	Potential to Emit (tpy)
Reactor Charge Heater	CO_2	6.39	116.997	1	40CFR98	748	3,275
Reactor Charge Heater	CH_4	6.39	0.0022	25	40CFR98	0.35	1.54
Reactor Charge Heater	N_2O	6.39	0.00022	298	40CFR98	0.42	1.83
Total	**CO_2e**					**748**	**3,278**

(1) Global Warming Potentials Included (CO_2 = 1, NH_4 = 25, N_2O = 298)

Fractionator Feed Heater GHG Emissions

Fractionator Feed Heater (EU40) Capacity 11.23 MMBtu/hr Natural Gas Usage 94.86 MMscf/yr

Emission Point	Pollutant	Max Throughput (MMBtu/hr)	Emission Factor (lb/MMBtu)	GWP (1)	Citation	Potential to Emit (lbs/hr)	Potential to Emit (tpy)
Fractionator Feed Heater	CO_2	11.23	116.997	1	40CFR98	1,314	5,755
Fractionator Feed Heater	CH_4	11.23	0.0022	25	40CFR98	0.62	2.71
Fractionator Feed Heater	N_2O	11.23	0.00022	298	40CFR98	0.74	3.22
Total	**CO_2e**					**1,315**	**5,761**

(1) Global Warming Potentials Included (CO_2 = 1, NH_4 = 25, N_2O = 298)

Front End Loaders GHG Emissions

Front End Loader #1 (EU31) Capacity 0.64MMBtu/hr, 13 gallons/hr
Front End Loader #2 (EU32) Capacity 0.64 MMBtu/hr, 13 gallons/hr

Emission Point	Pollutant	Emission Factor Gram/gal	Emission Factor (lb/gal)	Citation	Potential to Emit (lbs/hr)	Potential to Emit (tpy)
Front End Loader #1	CO_2	10,210	22.51	EPA 430-R-15-003	292.62	1281.67
Front End Loader #2	CO_2	10,210	22.51	EPA 430-R-15-003	292.62	640.84
Front End Loader #1	CH_4	410	9.04E-01	EPA 430-R-15-003	11.75	51.47
Front End Loader #2	CH_4	410	9.04E-01	EPA 430-R-15-003	11.75	25.73
Front End Loader #1	N_2O	80	1.76E-01	EPA 430-R-15-003	2.29	10.04
Front End Loader #2	N_2O	80	1.76E-01	EPA 430-R-15-003	2.29	5.02
Front End Loader #1	CO_2e	---			307	1,343
Front End Loader #2	CO_2e	---			307	672
Total	**CO_2e**	**---**			**613**	**2,015**

Amine CO_2 Removal GHG Emissions

Amine CO_2 Removal (EU16)

Unit Description	Pollutant	Max Throughput	Emission Factor	Citation	Potential to Emit	
		(dscfm)	(ppm)		(lbs/hr)	(tpy)
Amine CO_2 Removal	Biogenic CO_2	2,668	942,600	Engineering Estimate	17,234	75,485
Amine CO_2 Removal	CO_2e	---	---	40CFR98 (1)	17,234	75,485

(1) Global Warming Potentials (CO_2 = 1)

Greenhouse Gas (CO_{2e}) Emissions Summary:

Process/Emission Unit	GHG CO_2e
	Tons/year
SCR Stack	136,539
Flare - Pilot	744
Flare - Gasifier	2,308
Emergency Fire Pump	7.18
Reactor Charge Heater	3,278
Fractionator Feed Heater	5,761
Front End Loader #1	1,343.18
Front End Loader #2	671.59
Amine CO2 Removal	75,485
Total GHG CO_2e	**226,136**

Facility Wide Potential to Emit:

Summary of Facility Wide PTE								
	Pollutant							
Source	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**CO**	**NO_x**	**VOC**	**GHG CO_2e**
	(tons/year)							
Biomass Truck Receiving #1	3.59E-02	3.59E-02	3.59E-02	---	---	---	---	---
Biomass Truck Receiving #2	3.59E-02	3.59E-02	3.59E-02	---	---	---	---	---
Biomass Conveying & Shredder	1.36E-02	1.36E-02	1.36E-02	---	---	---	---	---
Biomass Conveyor System	1.06	5.01E-01	7.59E-02	---	---	---	---	---
Biomass Storage Pile	2.42	1.21	6.05E-01	---	---	---	---	---
Biomass Handling	2.65E-01	1.25E-01	1.90E-02	---	---	---	---	---
SCR Stack	8.54	8.54	5.77	6.75E-01	30.66	26.28	6.18	136,539
Gasifier Flare Exhaust Stack	1.41E-01	1.33E-01	1.01E-01	5.04E-01	6.71	1.97	2.83	3,051
Oil Water Separator	---	---	---	---	---	---	3.89E-02	---
Amine CO_2 Removal	---	---	---	---	---	---	---	75,485
Cooling Tower	7.88E-01	7.88E-01	7.88E-01	---	---	---	---	---
Emergency Fire Pump	1.36E-02	1.36E-02	1.36E-02	1.27E-02	4.17E-02	1.94E-01	1.58E-02	7
Reactor Charge Heater	2.05E-01	2.05E-01	2.05E-01	1.62E-02	8.68	2.02E	1.48E-01	3,278
Fractionator Feed Heater	3.60E-01	3.60E-01	3.60E-01	2.85E-02	15.25	3.56E	2.61E-01	5,761
Biochar Silo	9.39E-03	9.39E-03	9.39E-03	---	---	---	---	---
Product Loadout - Truck	---	---	---	---	---	---	8.61E-02	---
Product Loadout - Rail	---	---	---	---	---	---	5.16E-02	---
Truck Traffic	1.24	0.25	6.08E-02	---	---	---	---	---
Front End Loader #1	3.60E-02	3.60E-02	3.60E-02	4.87E-06	6.31	7.23E-01	3.43E-01	1,343
Front End Loader #2	1.80E-02	1.80E-02	1.80E-02	2.44E-06	3.15	3.61E-01	1.71E-01	672
Equipment Leaks	---	---	---	---	---	---	8.03	---
Jet Fuel Tank	---	---	---	---	---	---	1.28E-01	---
Jet Fuel Day Tank 1	---	---	---	---	---	---	1.34E-02	---
Jet Fuel Day Tank 2	---	---	---	---	---	---	1.34E-02	---
Diesel Tank	---	---	---	---	---	---	5.28E-02	---
Diesel Day Tank	---	---	---	---	---	---	1.29E-02	---
Naphtha Tank	---	---	---	---	---	---	5.54E-01	---
Off-Spec Tank	---	---	---	---	---	---	5.44E-01	---
Total PTE (tons/yr)	**15.19**	**12.28**	**8.15**	**1.24**	**70.80**	**35.11**	**19.48**	**226,136**
Proposed PSELs	**24**	**14**	**9**	**39**	**99**	**39**	**39**	**226,136**

HAZARDOUS AIR POLLUTANTS AND TOXIC AIR CONTAMINANTS

The Hazardous Air Pollutants (HAPs) emission inventory are provided in the tables below. The HAP emissions are calculated using the potential to emit for each pollutant using the maximum throughput and established emission factors. The list of potential Toxic Air Contaminants (TAC) pollutant was reported by the permittee in 2016. Since the facility had not yet been constructed or operated, no TAC emissions had been reported. References for the HAP emission factors are also provided.

Natural Gas Combustion from the Turbine (EU33) and the Recycle Heater (EU34) at the SCR

Hazardous Air Pollutant	Max Throughput	Emission Factor	Citation	Potential to Emit SCR Stack	
	(MMscf/hr)	(lb/MMscf)		(lbs/hr)	(tpy)
2-Methylnaphthalene	0.2567	2.40E-05	AP-42 Section 1.4	6.16E-06	2.70E-05
3-Methylchloranthrene	0.2567	1.80E-06	AP-42 Section 1.4	4.62E-07	2.02E-06
7, 12-Dimethylbenz(a)anthracene	0.2567	1.60E-05	AP-42 Section 1.4	4.11E-06	1.80E-05
Acenapthene	0.2567	1.80E-06	AP-42 Section 1.4	4.62E-07	2.02E-06
Acenapthylene	0.2567	1.80E-06	AP-42 Section 1.4	4.62E-07	2.02E-06
Anthracene	0.2567	2.40E-06	AP-42 Section 1.4	6.16E-07	2.70E-06
Arsenic	0.2567	2.00E-04	AP-42 Section 1.4	5.13E-05	2.25E-04
Benz(a)anthracene	0.2567	1.80E-06	AP-42 Section 1.4	4.62E-07	2.02E-06
Benzene	0.2567	2.10E-03	AP-42 Section 1.4	5.39E-04	2.36E-03
Benzo(a)pyrene	0.2567	1.20E-06	AP-42 Section 1.4	3.08E-07	1.35E-06
Benzo(b)fluoranthene	0.2567	1.80E-06	AP-42 Section 1.4	4.62E-07	2.02E-06
Benzo(g,h,i)perylene	0.2567	1.20E-06	AP-42 Section 1.4	3.08E-07	1.35E-06
Benzo(k)fluoranthene	0.2567	1.80E-06	AP-42 Section 1.4	4.62E-07	2.02E-06
Beryllium	0.2567	1.20E-05	AP-42 Section 1.4	3.08E-06	1.35E-05
Cadmium	0.2567	1.10E-03	AP-42 Section 1.4	2.82E-04	1.24E-03
Chromium	0.2567	1.40E-03	AP-42 Section 1.4	3.59E-04	1.57E-03
Chrysene	0.2567	1.80E-06	AP-42 Section 1.4	4.62E-07	2.02E-06
Cobalt	0.2567	8.40E-05	AP-42 Section 1.4	2.16E-05	9.44E-05
Dibenzo(a,h)anthracene	0.2567	1.20E-06	AP-42 Section 1.4	3.08E-07	1.35E-06
Dichlorobenzene	0.2567	1.20E-03	AP-42 Section 1.4	3.08E-04	1.35E-03
Fluoranthene	0.2567	3.00E-06	AP-42 Section 1.4	7.70E-07	3.37E-06
Fluorene	0.2567	2.80E-06	AP-42 Section 1.4	7.19E-07	3.15E-06
Formaldehyde	0.2567	7.50E-02	AP-42 Section 1.4	1.93E-02	8.43E-02
Hexane	0.2567	1.80E+00	AP-42 Section 1.4	4.62E-01	2.02
Indeno(1,2,3-cd)pyrene	0.2567	1.80E-06	AP-42 Section 1.4	4.62E-07	2.02E-06
Lead	0.2567	5.00E-04	AP-42 Section 1.4	1.28E-04	5.62E-04
Manganese	0.2567	3.80E-04	AP-42 Section 1.4	9.75E-05	4.27E-04
Mercury	0.2567	2.60E-04	AP-42 Section 1.4	6.67E-05	2.92E-04
Naphthalene	0.2567	6.10E-04	AP-42 Section 1.4	1.57E-04	6.86E-04
Nickel	0.2567	2.10E-03	AP-42 Section 1.4	5.39E-04	2.36E-03
Phenanathrene	0.2567	1.70E-05	AP-42 Section 1.4	4.36E-06	1.91E-05
Pyrene	0.2567	5.00E-06	AP-42 Section 1.4	1.28E-06	5.62E-06
Selenium	0.2567	2.40E-05	AP-42 Section 1.4	6.16E-06	2.70E-05
Toluene	0.2567	3.40E-03	AP-42 Section 1.4	8.73E-04	3.82E-03
			Total HAPs (tons/yr)	**4.85E-01**	**2.12**

Natural Gas Combustion from the Gasifier Pilot Flare Stack (EU15)

Hazardous Air Pollutant	Max Throughput	Emission Factor	Citation	Potential to Emit	
				Gasifier Flare Pilot	
	(MMscf/hr)	(lb/MMscf)		(lbs/hr)	(tpy)
2-Methylnaphthalene	0.0014	2.40E-05	AP-42 Section 1.4	3.36E-08	1.47E-07
3-Methylchloranthrene	0.0014	1.80E-06	AP-42 Section 1.4	2.52E-09	1.10E-08
7, 12-Dimethylbenz(a)anthracene	0.0014	1.60E-05	AP-42 Section 1.4	2.24E-08	9.80E-08
Acenapthene	0.0014	1.80E-06	AP-42 Section 1.4	2.52E-09	1.10E-08
Acenapthylene	0.0014	1.80E-06	AP-42 Section 1.4	2.52E-09	1.10E-08
Anthracene	0.0014	2.40E-06	AP-42 Section 1.4	3.36E-09	1.47E-08
Arsenic	0.0014	2.00E-04	AP-42 Section 1.4	2.80E-07	1.22E-06
Benz(a)anthracene	0.0014	1.80E-06	AP-42 Section 1.4	2.52E-09	1.10E-08
Benzene	0.0014	2.10E-03	AP-42 Section 1.4	2.94E-06	1.29E-05
Benzo(a)pyrene	0.0014	1.20E-06	AP-42 Section 1.4	1.68E-09	7.35E-09
Benzo(b)fluoranthene	0.0014	1.80E-06	AP-42 Section 1.4	2.52E-09	1.10E-08
Benzo(g,h,i)perylene	0.0014	1.20E-06	AP-42 Section 1.4	1.68E-09	7.35E-09
Benzo(k)fluoranthene	0.0014	1.80E-06	AP-42 Section 1.4	2.52E-09	1.10E-08
Beryllium	0.0014	1.20E-05	AP-42 Section 1.4	1.68E-08	7.35E-08
Cadmium	0.0014	1.10E-03	AP-42 Section 1.4	1.54E-06	6.74E-06
Chromium	0.0014	1.40E-03	AP-42 Section 1.4	1.96E-06	8.57E-06
Chrysene	0.0014	1.80E-06	AP-42 Section 1.4	2.52E-09	1.10E-08
Cobalt	0.0014	8.40E-05	AP-42 Section 1.4	1.17E-07	5.14E-07
Dibenzo(a,h)anthracene	0.0014	1.20E-06	AP-42 Section 1.4	1.68E-09	7.35E-09
Dichlorobenzene	0.0014	1.20E-03	AP-42 Section 1.4	1.68E-06	7.35E-06
Fluoranthene	0.0014	3.00E-06	AP-42 Section 1.4	4.19E-09	1.84E-08
Fluorene	0.0014	2.80E-06	AP-42 Section 1.4	3.92E-09	1.71E-08
Formaldehyde	0.0014	7.50E-02	AP-42 Section 1.4	1.05E-04	4.59E-04
Hexane	0.0014	1.80E+00	AP-42 Section 1.4	2.52E-03	1.10E-02
Indeno(1,2,3-cd)pyrene	0.0014	1.80E-06	AP-42 Section 1.4	2.52E-09	1.10E-08
Lead	0.0014	5.00E-04	AP-42 Section 1.4	6.99E-07	3.06E-06
Manganese	0.0014	3.80E-04	AP-42 Section 1.4	5.31E-07	2.33E-06
Mercury	0.0014	2.60E-04	AP-42 Section 1.4	3.64E-07	1.59E-06
Naphthalene	0.0014	6.10E-04	AP-42 Section 1.4	8.53E-07	3.74E-06
Nickel	0.0014	2.10E-03	AP-42 Section 1.4	2.94E-06	1.29E-05
Phenanathrene	0.0014	1.70E-05	AP-42 Section 1.4	2.38E-08	1.04E-07
Pyrene	0.0014	5.00E-06	AP-42 Section 1.4	6.99E-09	3.06E-08
Selenium	0.0014	2.40E-05	AP-42 Section 1.4	3.36E-08	1.47E-07
Toluene	0.0014	3.40E-03	AP-42 Section 1.4	4.75E-06	2.08E-05
			Total HAPs (tons/yr)	**2.64E-03**	**1.16E-02**

Process Gas Combustion from start-ups and upsets at the Gasifier Flare Stack (EU14)

Hazardous Air Pollutant	Max Throughput	Emission Factor	Citation	Potential to Emit Gasifier Process Gas Flare	
	(MMBtu/hr)	(lb/MMBtu)		(lbs/hr)	(tpy)
Acetaldehyde	400	8.30E-04	AP-42 Section 1.6	3.32E-01	1.66E-02
Acetophtnone	400	3.20E-09	AP-42 Section 1.6	1.28E-06	6.40E-08
Acrolein	400	4.00E-03	AP-42 Section 1.6	1.60E+00	8.00E-02
Benzene	400	4.20E-03	AP-42 Section 1.6	1.68E+00	8.40E-02
Bis(2-Ethylhexyl)phthalate	400	4.70E-08	AP-42 Section 1.6	1.88E-05	9.40E-07
Carbon Tetrachloride	400	4.50E-05	AP-42 Section 1.6	1.80E-02	9.00E-04
Chlorine	400	7.90E-04	AP-42 Section 1.6	3.16E-01	1.58E-02
Chlorobenzene	400	3.30E-05	AP-42 Section 1.6	1.32E-02	6.60E-04
Chloroform	400	2.80E-05	AP-42 Section 1.6	1.12E-02	5.60E-04
2,4-Dinitrophenol	400	1.80E-07	AP-42 Section 1.6	7.20E-05	3.60E-06
Ethylbenzene	400	3.10E-05	AP-42 Section 1.6	1.24E-02	6.20E-04
Naphthalene	400	9.70E-05	AP-42 Section 1.6	3.88E-02	1.94E-03
Styrene	400	1.90E-03	AP-42 Section 1.6	7.60E-01	3.80E-02
2,3,7,8-Tetrachlorodibenzo-p-dioxins	400	8.60E-12	AP-42 Section 1.6	3.44E-09	1.72E-10
Toluene	400	9.20E-04	AP-42 Section 1.6	3.68E-01	1.84E-02
Vinyl Chloride	400	1.80E-05	AP-42 Section 1.6	7.20E-03	3.60E-04
Xylene	400	2.50E-05	AP-42 Section 1.6	1.00E-02	5.00E-04
Antimony	400	7.90E-06	AP-42 Section 1.6	3.16E-03	1.58E-04
Beryllium	400	1.10E-06	AP-42 Section 1.6	4.40E-04	2.20E-05
Cadmium	400	4.10E-06	AP-42 Section 1.6	1.64E-03	8.20E-05
Chromium	400	2.10E-05	AP-42 Section 1.6	8.40E-03	4.20E-04
Cobalt	400	6.60E-06	AP-42 Section 1.6	2.64E-03	1.32E-04
Lead	400	4.80E-05	AP-42 Section 1.6	1.92E-02	9.60E-04
Manganese	400	1.60E-03	AP-42 Section 1.6	6.40E-01	3.20E-02
Mercury	400	3.50E-06	AP-42 Section 1.6	1.40E-03	7.00E-05
Nickel	400	3.30E-05	AP-42 Section 1.6	1.32E-02	6.60E-04
Selenium	400	2.80E-06	AP-42 Section 1.6	1.12E-03	5.60E-05
			Total HAPs (tons/yr)	**5.86**	**0.29**

Diesel Gas Combustion from the Emergency Fire Pump (EU22)

Hazardous Air Pollutant	Max Throughput	Emission Factor	Citation	Potential to Emit Emergency Fire Pump	
	(MMBtu/hr)	(lb/MMBtu)		(lbs/hr)	(tpy)
Benzene	0.88	9.33E-04	AP-42 Section 3.3	8.19E-04	4.10E-05
Toluene	0.88	4.09E-04	AP-42 Section 3.3	3.59E-04	1.80E-05
Xylenes	0.88	2.85E-04	AP-42 Section 3.3	2.50E-04	1.25E-05
1,3-Butadiene	0.88	3.91E-05	AP-42 Section 3.3	3.43E-05	1.72E-06
Formaldehdye	0.88	1.18E-03	AP-42 Section 3.3	1.04E-03	5.18E-05
Acetaldehyde	0.88	7.67E-04	AP-42 Section 3.3	6.73E-04	3.37E-05
Acrolein	0.88	9.25E-03	AP-42 Section 3.3	8.12E-03	4.06E-04
Naphthalene	0.88	8.48E-05	AP-42 Section 3.3	7.45E-05	3.72E-06
			Total HAPs (tons/yr)	**1.14E-02**	**5.68E-04**

Natural Gas Combustion from the Reactor Charge Heater (EU39)

Hazardous Air Pollutant	Max Throughput	Emission Factor	Citation	Potential to Emit	
				Reactor Charge Heater	
	(MMscf/hr)	(lb/MMscf)		(lbs/hr)	(tpy)
2-Methylnaphthalene	0.0062	2.40E-05	AP-42 Section 1.4	1.48E-07	6.48E-07
3-Methylchloranthrene	0.0062	1.80E-06	AP-42 Section 1.4	1.11E-08	4.86E-08
7, 12-Dimethylbenz(a)anthracene	0.0062	1.60E-05	AP-42 Section 1.4	9.86E-08	4.32E-07
Acenapthene	0.0062	1.80E-06	AP-42 Section 1.4	1.11E-08	4.86E-08
Acenapthylene	0.0062	1.80E-06	AP-42 Section 1.4	1.11E-08	4.86E-08
Anthracene	0.0062	2.40E-06	AP-42 Section 1.4	1.48E-08	6.48E-08
Arsenic	0.0062	2.00E-04	AP-42 Section 1.4	1.23E-06	5.40E-06
Benz(a)anthracene	0.0062	1.80E-06	AP-42 Section 1.4	1.11E-08	4.86E-08
Benzene	0.0062	2.10E-03	AP-42 Section 1.4	1.29E-05	5.67E-05
Benzo(a)pyrene	0.0062	1.20E-06	AP-42 Section 1.4	7.39E-09	3.24E-08
Benzo(b)fluoranthene	0.0062	1.80E-06	AP-42 Section 1.4	1.11E-08	4.86E-08
Benzo(g,h,i)perylene	0.0062	1.20E-06	AP-42 Section 1.4	7.39E-09	3.24E-08
Benzo(k)fluoranthene	0.0062	1.80E-06	AP-42 Section 1.4	1.11E-08	4.86E-08
Beryllium	0.0062	1.20E-05	AP-42 Section 1.4	7.39E-08	3.24E-07
Cadmium	0.0062	1.10E-03	AP-42 Section 1.4	6.78E-06	2.97E-05
Chromium	0.0062	1.40E-03	AP-42 Section 1.4	8.63E-06	3.78E-05
Chrysene	0.0062	1.80E-06	AP-42 Section 1.4	1.11E-08	4.86E-08
Cobalt	0.0062	8.40E-05	AP-42 Section 1.4	5.18E-07	2.27E-06
Dibenzo(a,h)anthracene	0.0062	1.20E-06	AP-42 Section 1.4	7.39E-09	3.24E-08
Dichlorobenzene	0.0062	1.20E-03	AP-42 Section 1.4	7.39E-06	3.24E-05
Fluoranthene	0.0062	3.00E-06	AP-42 Section 1.4	1.85E-08	8.10E-08
Fluorene	0.0062	2.80E-06	AP-42 Section 1.4	1.73E-08	7.56E-08
Formaldehyde	0.0062	7.50E-02	AP-42 Section 1.4	4.62E-04	2.02E-03
Hexane	0.0062	1.80E+00	AP-42 Section 1.4	1.11E-02	4.86E-02
Indeno(1,2,3-cd)pyrene	0.0062	1.80E-06	AP-42 Section 1.4	1.11E-08	4.86E-08
Lead	0.0062	5.00E-04	AP-42 Section 1.4	3.08E-06	1.35E-05
Manganese	0.0062	3.80E-04	AP-42 Section 1.4	2.34E-06	1.03E-05
Mercury	0.0062	2.60E-04	AP-42 Section 1.4	1.60E-06	7.02E-06
Naphthalene	0.0062	6.10E-04	AP-42 Section 1.4	3.76E-06	1.65E-05
Nickel	0.0062	2.10E-03	AP-42 Section 1.4	1.29E-05	5.67E-05
Phenanathrene	0.0062	1.70E-05	AP-42 Section 1.4	1.05E-07	4.59E-07
Pyrene	0.0062	5.00E-06	AP-42 Section 1.4	3.08E-08	1.35E-07
Selenium	0.0062	2.40E-05	AP-42 Section 1.4	1.48E-07	6.48E-07
Toluene	0.0062	3.40E-03	AP-42 Section 1.4	2.10E-05	9.18E-05
			Total HAPs (tons/yr)	**1.16E-02**	**0.05**

Natural Gas Combustion from the Fractionator Feed Heater (EU40)

Hazardous Air Pollutant	Max Throughput	Emission Factor	Citation	Potential to Emit	
				Reactor Charge Heater	
	(MMscf/hr)	(lb/MMscf)		(lbs/hr)	(tpy)
2-Methylnaphthalene	0.0108	2.40E-05	AP-42 Section 1.4	2.60E-07	1.14E-06
3-Methylchloranthrene	0.0108	1.80E-06	AP-42 Section 1.4	1.95E-08	8.54E-08
7, 12-Dimethylbenz(a)anthracene	0.0108	1.60E-05	AP-42 Section 1.4	1.73E-07	7.59E-07
Acenapthene	0.0108	1.80E-06	AP-42 Section 1.4	1.95E-08	8.54E-08
Acenapthylene	0.0108	1.80E-06	AP-42 Section 1.4	1.95E-08	8.54E-08
Anthracene	0.0108	2.40E-06	AP-42 Section 1.4	2.60E-08	1.14E-07
Arsenic	0.0108	2.00E-04	AP-42 Section 1.4	2.17E-06	9.49E-06
Benz(a)anthracene	0.0108	1.80E-06	AP-42 Section 1.4	1.95E-08	8.54E-08
Benzene	0.0108	2.10E-03	AP-42 Section 1.4	2.27E-05	9.96E-05
Benzo(a)pyrene	0.0108	1.20E-06	AP-42 Section 1.4	1.30E-08	5.69E-08
Benzo(b)fluoranthene	0.0108	1.80E-06	AP-42 Section 1.4	1.95E-08	8.54E-08
Benzo(g,h,i)perylene	0.0108	1.20E-06	AP-42 Section 1.4	1.30E-08	5.69E-08
Benzo(k)fluoranthene	0.0108	1.80E-06	AP-42 Section 1.4	1.95E-08	8.54E-08
Beryllium	0.0108	1.20E-05	AP-42 Section 1.4	1.30E-07	5.69E-07
Cadmium	0.0108	1.10E-03	AP-42 Section 1.4	1.19E-05	5.22E-05
Chromium	0.0108	1.40E-03	AP-42 Section 1.4	1.52E-05	6.64E-05
Chrysene	0.0108	1.80E-06	AP-42 Section 1.4	1.95E-08	8.54E-08
Cobalt	0.0108	8.40E-05	AP-42 Section 1.4	9.10E-07	3.98E-06
Dibenzo(a,h)anthracene	0.0108	1.20E-06	AP-42 Section 1.4	1.30E-08	5.69E-08
Dichlorobenzene	0.0108	1.20E-03	AP-42 Section 1.4	1.30E-05	5.69E-05
Fluoranthene	0.0108	3.00E-06	AP-42 Section 1.4	3.25E-08	1.42E-07
Fluorene	0.0108	2.80E-06	AP-42 Section 1.4	3.03E-08	1.33E-07
Formaldehyde	0.0108	7.50E-02	AP-42 Section 1.4	8.12E-04	3.56E-03
Hexane	0.0108	1.80E+00	AP-42 Section 1.4	1.95E-02	8.54E-02
Indeno(1,2,3-cd)pyrene	0.0108	1.80E-06	AP-42 Section 1.4	1.95E-08	8.54E-08
Lead	0.0108	5.00E-04	AP-42 Section 1.4	5.41E-06	2.37E-05
Manganese	0.0108	3.80E-04	AP-42 Section 1.4	4.12E-06	1.80E-05
Mercury	0.0108	2.60E-04	AP-42 Section 1.4	2.82E-06	1.23E-05
Naphthalene	0.0108	6.10E-04	AP-42 Section 1.4	6.61E-06	2.89E-05
Nickel	0.0108	2.10E-03	AP-42 Section 1.4	2.27E-05	9.96E-05
Phenanathrene	0.0108	1.70E-05	AP-42 Section 1.4	1.84E-07	8.06E-07
Pyrene	0.0108	5.00E-06	AP-42 Section 1.4	5.41E-08	2.37E-07
Selenium	0.0108	2.40E-05	AP-42 Section 1.4	2.60E-07	1.14E-06
Toluene	0.0108	3.40E-03	AP-42 Section 1.4	3.68E-05	1.61E-04
Total HAPs (tons/yr)				**2.05E-02**	**0.09**

Diesel Gas Combustion from the Front End Loader #1 (EU31)

Hazardous Air Pollutant	Max Throughput	Emission Factor	Citation	Potential to Emit	
				Front End Loader #1	
	(MMBtu/hr)	(lb/MMBtu)		(lbs/hr)	(tpy)
Acetaldehyde	0.64	5.30E-02	Fraction VOC	4.14E-03	1.82E-02
Acrolein	0.64	3.00E-03	Fraction VOC	2.35E-04	1.03E-03
Benzene	0.64	2.00E-02	Fraction VOC	1.56E-03	6.85E-03
1,3-Butadiene	0.64	2.00E-03	Fraction VOC	1.56E-04	6.85E-04
Formaldehdye	0.64	1.18E-01	Fraction VOC	9.23E-03	4.04E-02
			Total HAPs (tons/yr)	**1.53E-02**	**6.71E-02**

Diesel Gas Combustion from the Front End Loader #2 (EU32)

Hazardous Air Pollutant	Max Throughput	Emission Factor	Citation	Potential to Emit	
				Front End Loader #2	
	(MMBtu/hr)	(lb/MMBtu)		(lbs/hr)	(tpy)
Acetaldehyde	0.64	5.30E-02	Fraction VOC	4.14E-03	9.08E-03
Acrolein	0.64	3.00E-03	Fraction VOC	2.35E-04	5.14E-04
Benzene	0.64	2.00E-02	Fraction VOC	1.56E-03	3.43E-03
1,3-Butadiene	0.64	2.00E-03	Fraction VOC	1.56E-04	3.43E-04
Formaldehdye	0.64	1.18E-01	Fraction VOC	9.23E-03	2.02E-02
			Total HAPs (tons/yr)	**1.53E-02**	**3.36E-02**

Hazardous Air Pollutant emissions from the carbon canister at the Truck Product Load-Out (EU27)

Hazardous Air Pollutant	Max Throughput		Emission Factor	Citation	Potential to Emit	
	VOC (lbs/hr)	VOC (tons/yr)	% of VOC		Truck Load-out	
					(lbs/hr)	(tpy)
Jet Fuel						
Naphthalene	1.35E-02	1.74E-03	≤4% of VOC	AP-42 Section 5.2	5.38E-04	6.95E-05
Diesel Fuel						
Naphthalene	1.25E-02	7.44E-04	≤2% of VOC	AP-42 Section 5.2	2.49E-04	1.49E-05
Cumene	1.25E-02	7.44E-04	≤1% of VOC	AP-42 Section 5.2	1.25E-04	7.44E-06
Ethylbenzene	1.25E-02	7.44E-04	≤1% of VOC	AP-42 Section 5.2	1.25E-04	7.44E-06
Naphtha						
Hexane	1.74	8.36E-02	25% of VOC	AP-42 Section 5.2	4.34E-01	2.09E-02
Xylene	1.74	8.36E-02	25% of VOC	AP-42 Section 5.2	4.34E-01	2.09E-02
Toluene	1.74	8.36E-02	15% of VOC	AP-42 Section 5.2	2.60E-01	1.25E-02
Ethylbenzene	1.74	8.36E-02	5% of VOC	AP-42 Section 5.2	8.68E-02	4.18E-03
Benzene	1.74	8.36E-02	5% of VOC	AP-42 Section 5.2	8.68E-02	4.18E-03
				Total HAPs (tons/yr)	**3.07**	**6.28E-02**

Hazardous Air Pollutant emissions from the carbon canister at the Rail Product Load-Out (EU28)

Hazardous Air Pollutant	Max Throughput		Emission Factor	Citation	Potential to Emit	
	VOC	VOC			Rail Load-out	
	(lbs/hr)	(tons/yr)	% of VOC		(lbs/hr)	(tpy)
Jet Fuel						
Naphthalene	8.07E-03	1.04E-03	≤4% of VOC	AP-42 Section 5.2	3.23E-04	4.17E-05
Diesel Fuel						
Naphthalene	7.48E-03	4.46E-04	≤2% of VOC	AP-42 Section 5.2	1.50E-04	8.93E-06
Cumene	7.48E-03	4.46E-04	≤1% of VOC	AP-42 Section 5.2	7.48E-05	4.46E-06
Ethylbenzene	7.48E-03	4.46E-04	≤1% of VOC	AP-42 Section 5.2	7.48E-05	4.46E-06
Naphtha						
Hexane	1.04	5.01E-02	25% of VOC	AP-42 Section 5.2	2.60E-01	1.25E-02
Xylene	1.04	5.01E-02	25% of VOC	AP-42 Section 5.2	2.60E-01	1.25E-02
Toluene	1.04	5.01E-02	15% of VOC	AP-42 Section 5.2	1.56E-01	7.52E-03
Ethylbenzene	1.04	5.01E-02	5% of VOC	AP-42 Section 5.2	5.21E-02	2.51E-03
Benzene	1.04	5.01E-02	5% of VOC	AP-42 Section 5.2	5.21E-02	2.51E-03
				Total HAPs (tons/yr)	**1.84**	**3.77E-02**

Hazardous Air Pollutant emissions calculated from the equipment leaks (FS10)

Hazardous Air Pollutant	Max Throughput		Emission Factor	Citation	Potential to Emit	
	VOC	VOC			Equipment Leaks	
	(lbs/hr)	(tons/yr)	% of VOC		(lbs/hr)	(tpy)
Naphthalene	1.83	8.03	4% of VOC	NSPS Subpart Vva	7.33E-02	3.21E-01
Ethylbenzene	1.83	8.03	7% of VOC	NSPS Subpart Vva	1.28E-01	5.62E-01
Cumene	1.83	8.03	1% of VOC	NSPS Subpart Vva	1.83E-02	8.03E-02
Hexane	1.83	8.03	35% of VOC	NSPS Subpart Vva	6.42E-01	2.81
Xylene	1.83	8.03	35% of VOC	NSPS Subpart Vva	6.42E-01	2.81
Toluene	1.83	8.03	20% of VOC	NSPS Subpart Vva	3.67E-01	1.61
Benzene	1.83	8.03	5% of VOC	NSPS Subpart Vva	9.17E-02	4.02E-01
				Total HAPs (tons/yr)	**1.96**	**8.59**

Hazardous Air Pollutant emissions calculated from the storage tanks (TK01 – TK08)

Hazardous Air Pollutant	Max Throughput		Emission Factor	Citation	Potential to Emit	
	VOC	VOC			Rail Load-out	
	(lbs/hr)	(tons/yr)	% of VOC		(lbs/hr)	(tpy)
TK01 – Jet Fuel Tank						
Naphthalene	2.92E-02	1.28E-01	≤4% of VOC	Tanks 4.0.9	1.38E-03	6.02E-03
TK02 – Jet Fuel Day Tank 1						
Naphthalene	3.07E-03	1.34E-02	≤4% of VOC	Tanks 4.0.9	1.68E-04	7.34E-04
TK03 – Jet Fuel Day Tank 2						
Naphthalene	3.07E-03	1.34E-02	≤4% of VOC	Tanks 4.0.9	1.68E-04	7.34E-04
TK04 – Diesel Tank						
Naphthalene	1.20E-02	5.28E-02	≤2% of VOC	Tanks 4.0.9	5.23E-04	2.29E-03
Cumene	1.20E-02	5.28E-02	≤1% of VOC	Tanks 4.0.9	2.61E-04	1.14E-03
Ethylbenzene	1.20E-02	5.28E-02	≤1% of VOC	Tanks 4.0.9	2.61E-04	1.14E-03
TK06 – Diesel Day Tank						
Naphthalene	2.94E-03	1.29E-02	≤2% of VOC	Tanks 4.0.9	1.17E-04	5.10E-04
Cumene	2.94E-03	1.29E-02	≤1% of VOC	Tanks 4.0.9	5.83E-05	2.55E-04
Ethylbenzene	2.94E-03	1.29E-02	≤1% of VOC	Tanks 4.0.9	5.83E-05	2.55E-04
TK07 – Naphtha Tank						
Hexane	1.26E-01	5.54E-01	25% of VOC	Tanks 4.0.9	1.26E-01	5.54E-01
Xylene	1.26E-01	5.54E-01	25% of VOC	Tanks 4.0.9	3.16E-02	1.38E-01
Toluene	1.26E-01	5.54E-01	15% of VOC	Tanks 4.0.9	3.16E-02	1.38E-01
Ethylbenzene	1.26E-01	5.54E-01	5% of VOC	Tanks 4.0.9	1.90E-02	8.31E-02
Benzene	1.26E-01	5.54E-01	5% of VOC	Tanks 4.0.9	6.32E-03	2.77E-02
TK08 – Off-Spec Tank						
Hexane	1.24E-01	5.44E-01	25% of VOC	Tanks 4.0.9	1.24E-01	5.44E-01
Xylene	1.24E-01	5.44E-01	25% of VOC	Tanks 4.0.9	3.11E-02	1.36E-01
Toluene	1.24E-01	5.44E-01	15% of VOC	Tanks 4.0.9	3.11E-02	1.36E-01
Ethylbenzene	1.24E-01	5.44E-01	5% of VOC	Tanks 4.0.9	1.86E-02	8.16E-02
Benzene	1.24E-01	5.44E-01	5% of VOC	Tanks 4.0.9	6.21E-03	2.72E-02
				Total HAPs (tons/yr)	**1.91E-01**	**8.37E-01**

Summary of potential to emit for Hazardous Air Pollutants

Hazardous Air Pollutants	(lbs/yr)	(tons/yr)
Benzene	1120	5.60E-01
Ethylbenzene	1250	6.26E-01
Formaldehyde	302	1.51E-01
Hexane	10575	5.29
Naphthalene	663	3.35E-01
Toluene	3627	1.81
Xylene	6239	3.12
Sum of Highest HAPs (tons/yr)	**23777**	**11.89**
Sum of Other HAPs (tons/yr)	**616**	**0.31**
TOTAL HAPs (tons/yr)	**24393**	**12.20**